NUEVO ENERGY CO
Form 10-Q
November 08, 2002

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

FORM 10-Q

(Mark One)
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2002

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE TRANSITION PERIOD FROM ______________________ TO ________________________

COMMISSION FILE NUMBER 1-10537

NUEVO ENERGY COMPANY
(Exact Name of Registrant as Specified in Its Charter)

DELAWARE	76-0304436
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1021 MAIN, SUITE 2100, HOUSTON, TEXAS	77002
(Address of principal executive offices)	(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 [X] 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 6, 2002: 19,179,544.

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PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

NUEVO ENERGY COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(IN THOUSANDS, EXCEPT PER SHARE DATA)
(UNAUDITED)

	Quarter Ended September 30,	
	2002	2001
Revenues		
Crude oil and liquids....	$ 78,676	$ 71,263
Natural gas....	9,444	9,759

Other	3,515	98
	91,635	81,120
Costs and Expenses		
Lease operating expenses	39,524	39,797
Exploration costs	2,318	5,825
Depletion, depreciation and amortization	19,277	18,250
Impairment of oil and gas properties	--	134
General and administrative	6,525	9,502
Other	186	323
Loss (gain) on disposition of properties	(620)	(78)
	67,210	73,753
Income From Operations	24,425	7,367
Derivative gain (loss)	(3,371)	115
Interest income	53	268
Interest expense	(9,528)	(10,635)
Dividends on TECONS	(1,653)	(1,653)
Income (Loss) from Continuing Operations Before Income Tax	9,926	(4,538)
Income tax expense (benefit)		
Current	1,025	(76)
Deferred	2,996	(1,679)
	4,021	(1,755)
Net Income (Loss) From Continuing Operations	5,905	(2,783)
Income from discontinued operations, including loss on disposition, net of income taxes	250	400
Net Income (Loss)	$ 6,155	$ (2,383)
Earnings Per Share		
Basic		
Net income (loss) from continuing operations	$ 0.34	$ (0.16)
Net income from discontinued operations	0.01	0.02
Net income (loss)	$ 0.35	$ (0.14)
Diluted		
Net income (loss) from continuing operations	$ 0.34	$ (0.16)
Net income from discontinued operations	0.01	0.02
Net income (loss)	$ 0.35	$ (0.14)
Weighted Average Shares Outstanding		
Basic	17,399	16,877
Diluted	17,502	16,877

See accompanying notes.

NUEVO ENERGY COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
(IN THOUSANDS, EXCEPT SHARE AMOUNTS)

	Sep

	(U
ASSETS	
Current assets	
Cash and cash equivalents..	$
Accounts receivable, net	
Inventory..	
Assets held for sale	
Assets from price risk management activities.......................................	
Prepaid expenses and other...	
	-
Total current assets...	
	-
Property and equipment, at cost	
Oil and gas properties (successful efforts method).................................	1
Land...	
Gas plant facilities...	
Other property...	
	-
	1
Accumulated depletion, depreciation and amortization...............................	
	-
Total property and equipment, net..	
	-
Deferred tax assets, net...	
Goodwill...	
Other assets...	
	-
Total assets...	$
	=
LIABILITIES AND STOCKHOLDERS' EQUITY	
Current liabilities	
Accounts payable...	$
Accrued interest...	
Other accrued liabilities..	
	-
Total current liabilities..	
	-
Long-term debt	
9 3/8% Senior Subordinated Notes due 2010..	
9 1/2% Senior Subordinated Notes due 2008..	
9 1/2% Senior Subordinated Notes due 2006..	
Bank Line of Credit..	
Interest rate swaps..	
	-
Total long-term debt...	
	-
Other long-term liabilities..	
TECONS...	
Stockholders' equity	

Preferred stock, 7% Cumulative Convertible, $1.00 par value; 10,000,000 shares authorized; none issued and outstanding in 2002 and 2001.......................
Common stock, $0.01 par value, 50,000,000 shares authorized; issued 23,029,541 in 2002 and 20,905,796 in 2001..
Additional paid-in capital..
Treasury stock (at cost) 3,871,149 shares in 2002 and 3,902,721 shares in 2001.....
Stock held by benefit trust, 67,137 shares in 2002 and 122,995 shares in 2001...
Deferred stock compensation...
Accumulated other comprehensive income (loss)...................................
Accumulated deficit...

Total stockholders' equity..

Total liabilities and stockholders' equity...............................

See accompanying notes.

NUEVO ENERGY COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(IN THOUSANDS)
(UNAUDITED)

	Quarter Ended September 30,	
	2002	2001
Cash flows from operating activities		
Net income (loss).......................................	$ 6,155	$ (2,383)
Adjustments to reconcile net income to net cash provided by operating activities		
Depletion, depreciation and amortization..............	19,277	18,250
Dry hole costs..	--	4,506
Impairment of oil and gas properties..................	--	134
Amortization of debt financing costs..................	633	602
Loss (gain) on disposition of properties..............	(620)	(78)
Deferred income taxes.................................	2,996	(1,679)
Derivative (gain) loss................................	3,371	(115)
Non-cash effect of discontinued operations............	(144)	795
Other...	1,981	67
	33,649	20,099
Working capital and other changes, net of non-cash transactions		
Accounts receivable...................................	1,971	9,633
Accounts payable......................................	7,669	(14,740)
Other...	(4,789)	20,286
Net cash provided by operating activities..........	38,500	35,278

Cash flows from investing activities			
Additions to oil and gas properties	(9,302)	(34,188)	
Acquisition of Athanor Resources, Inc	(61,312)	--	
Acquisitions of oil and gas properties	--	(64)	
Additions to gas plants and other facilities	(1,318)	(1,173)	
Proceeds from sale of properties	2,112	--	
Net cash used in investing activities	(69,820)	(35,425)	
Cash flows from financing activities			
Debt issuance and modification costs	--	--	
Payments of long-term debt	--	(125)	
Net borrowings of credit facility	35,200	--	
Proceeds from exercise of stock options	--	68	
Purchase of treasury shares	--	--	
Other proceeds	--	--	
Net cash provided by(used in) financing activities	35,200	(57)	
Increase (decrease) in cash and cash equivalents	3,880	(204)	
Cash and cash equivalents			
Beginning of period	245	3,092	
End of period	$ 4,125	$ 2,888	$

See accompanying notes.

NUEVO ENERGY COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(IN THOUSANDS)
(UNAUDITED)

	Quarter Ended September 30,		
	2002	2001	
Net income (loss)	$ 6,155	$ (2,383)	$
Other comprehensive income, net of tax:			
Cumulative-effect transition adjustment	--	--	
Reclassification adjustment for settled contracts	3,586	6,072	
Net change in fair value of derivative instruments	(11,591)	4,070	
Other comprehensive income (loss)	(8,005)	10,142	

Comprehensive income (loss)..........................	$ (1,850)	$ 7,759	$

See accompanying notes.

NUEVO ENERGY COMPANY
NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION

Our 2001 Annual Report on Form 10-K includes a summary of our significant accounting policies and other disclosures. You should read it in conjunction with this Quarterly Report on Form 10-Q. The financial statements as of September 30, 2002, and for the quarters and nine months ended September 30, 2002 and 2001, are unaudited. The balance sheet as of December 31, 2001, is derived from the audited balance sheet filed in the Form 10-K. These financial statements have been prepared pursuant to the rules and regulations of the U.S. Securities and Exchange Commission and do not include all disclosures required by accounting principles generally accepted in the United States. We have made adjustments, all of which are of a normal, recurring nature, to fairly present our interim period results. Information for interim periods may not indicate the results of operations for the entire year due to the seasonal nature of our business. The prior period information also includes reclassifications which were made to conform to the current period presentation. These reclassifications have no effect on our reported net income, cash flows or stockholders' equity.

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 the Impairment or Disposal of Long-Lived Assets.

In October 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. This Statement requires that long-lived assets that are to be disposed of by sale be measured at the lower of book value or fair value less cost to sell. The standard also expanded the scope of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. We adopted the provisions of this statement effective January 1, 2002 and have presented certain property dispositions as discontinued operations in accordance with SFAS No. 144. (See Note 3).

Goodwill and Other Intangible Assets.

In June 2001, the FASB issued SFAS No. 142, Goodwill and Other Intangible Assets. This Statement requires discontinuing amortization of goodwill after 2001 and requires that goodwill be tested for impairment. The impairment test requires allocating goodwill and all other assets and liabilities to business levels referred to as reporting units. The fair value of each reporting unit that has goodwill is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value (including goodwill), then a second test is performed to determine the amount of the impairment.

If the second test is necessary, 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 book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the amount of the impairment.

The goodwill impairment test is performed annually, and also at interim dates upon the occurrence of significant events. Significant events include: a significant adverse change in legal factors or business climate; an adverse action or assessment by a regulator; a more-likely-than-not expectation that a reporting unit or significant portion of a reporting unit will be sold; significant adverse trends in current and future oil and gas prices; nationalization of any of the Company's oil and gas properties; or, significant increases in a reporting unit's carrying value relative to its fair value. We adopted the provisions of this statement January 1, 2002. We did not have or record goodwill until the third quarter of 2002. During the third quarter 2002, we recorded $21.7 million of goodwill in connection with our acquisition of Athanor Resources, Inc. (See Note 2).

Accounting for Asset Retirement Obligations.

In August 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. This Statement requires companies to record a liability relating to the retirement and removal of assets used in their 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 are currently evaluating the effects of this pronouncement and will complete our evaluation during the fourth quarter of 2002. We will adopt this standard on January 1, 2003.

Accounting for Gains and Losses from Extinguishment of Debt.

In April 2002, the FASB issued SFAS No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections. This Statement rescinds SFAS No. 4, Reporting Gains and Losses from Extinguishment of Debt, which required all gains and losses from the extinguishment of debt to be aggregated and, if material, classified as an extraordinary item, net of income taxes. As a result, the criteria in Accounting Principles Board Opinion ("APB") 30 will now be used to classify those gains and losses. Any gain or loss on the extinguishment of debt that was classified as an extraordinary item in prior periods presented that does not meet the criteria in APB 30 for classification as an extraordinary item shall be reclassified. The provisions of this statement are effective for fiscal years beginning after January 1, 2003.

Accounting for Costs Associated with Exit or Disposal Activities.

In July 2002, the FASB issued SFAS No. 146, Accounting for Costs Associated with Exit or Disposal Activities. This Statement requires the recognition of costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. The provisions of this Statement are effective for exit or disposal activities initiated after December 31, 2002.

2. MERGER WITH ATHANOR RESOURCES, INC.

Effective September 18, 2002, pursuant to an Agreement and Plan of Merger, a wholly owned subsidiary of Nuevo Energy Company was merged with and into Athanor Resources, Inc. ("Athanor"), a Delaware corporation, and Athanor became the surviving wholly owned subsidiary of Nuevo Energy Company. In connection with the merger, Nuevo issued approximately 2.0 million shares of common stock for all of the common and preferred stock of Athanor. The results of Athanor's operations have been included in our consolidated financial statements effective September 18, 2002.

The merger was accounted for using the purchase method of accounting. The purchase price totaling approximately $101.4 million included a combination of $61.3 million of available cash and additional borrowings, the issuance of approximately $20.1 million of our common stock (approximately 2.0 million shares) to Athanor stockholders, and the fair value of the net liabilities assumed of approximately $20.0 million. The following table summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition. We are in the process of finalizing the fair value of the assets and liabilities assumed, thus, the allocation is subject to refinement.

	(In thousands)
Current assets	$ 2,008
Property, plant and equipment	101,737
Goodwill	21,745
Total assets acquired	125,490
Current liabilities	4,599
Long-term debt	20,000
Deferred tax liability	19,494
Total liabilities assumed	44,093
Net assets acquired	$ 81,397

The allocation of the purchase price resulted in approximately $21.7 million allocated to goodwill which is not expected to be deductible for tax purposes. This goodwill is attributable to a premium paid for Athanor because the acquisition gives Nuevo a new core area with increasing growth opportunities, diversifies our asset base with higher margin properties and was financed with a component of equity. Other accrued merger costs of $1.6 million include capitalizable third party transaction costs.

The merger included certain non-cash investing and financing activities not reflected in the Statement of Cash Flows as follows:

	(In thousands)
Common stock issued...	$ 20,086
Long-term debt assumed...	20,000

Subsequent to the acquisition, the long-term debt assumed of $20.0 million was paid off.

The following unaudited pro forma condensed income statement information has been prepared to give effect to the merger as if such transaction had occurred at the beginning of the periods presented. The historical results of operations have been adjusted to reflect the difference between Athanor's historical depletion, depreciation and amortization and such expense calculated based on the value allocated to the assets acquired in the merger. The information presented is not necessarily indicative of the results of future operations of the merged companies.

	Quarter Ended September 30,		Ni
	2002	2001	200
Revenues...	$ 97,127	$ 87,637	$ 26
Income (Loss) from Continuing Operations.............	6,764	(1,927)	2
Net Income (Loss)....................................	7,014	(1,534)	2
Earnings Per Share			
Basic			
Income (Loss) from Continuing Operations.......	0.35	(0.10)	
Net Income (Loss).............................	0.36	(0.08)	
Diluted			
Income (Loss) from Continuing Operations.......	0.35	(0.10)	
Net Income (Loss).............................	0.36	(0.08)	
NYMEX prices			
Crude oil.......................................	$ 28.27	$ 26.76	$
Natural gas.....................................	3.22	2.79	

3. DISCONTINUED OPERATIONS

In 2002, we sold a majority of our oil and gas properties located in Texas, Alabama and Louisiana (Eastern properties) for approximately $9.0 million. We recognized a $0.2 million gain on the sale of these properties. Historical results of operations from these properties and the gain on sale are classified as discontinued operations in our statements of income.

4. RESTRUCTURING AND SEVERANCE CHARGES

We terminated our California field operations and human resources outsourcing agreements effective March 15, 2002. We brought the human resources function in-house and we now employ the field employees working on our California properties. Our exploration and production operations were reorganized to create a smaller, more focused exploitation program and we eliminated our California exploration program along with approximately 20 technical positions in late 2001. The following table details the amounts related to our restructuring:

	Liability at December 31, 2001	Payments in 2002	
		(In thousands)	
Severance, benefits and other....	$ 1,675	$ 1,675	$
Contract termination	2,681	2,681	
	$ 4,356	$ 4,356	$

5. 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. The reconciliation is as follows:

	Quarter Ended September 30,		
	2002		2
	Net Income	Shares	Net Income
		(in thousands)	
Basic Earnings Per Share			
Income (loss) from continuing operations..................	$5,905	17,399	$(2,783
Income (loss) from discontinued operations.................	250		400
Earnings Basic.......................	6,155		$(2,383
Effect of Diluted Securities			
Stock options and restricted stock.......................		38	
Shares held by benefit trust....		65	
Earnings - Diluted..................	$6,155	17,502	$(2,383

	Year to Date Ended September 30,		
	2002		2
	Net Income	Shares	Net Income
		(in thousands)	
Basic Earnings Per Share			
Income (loss) from continuing operations.................	$23,483	17,161	$7,183
Income (loss) from discontinued operations.................	700		2,696
Earnings Basic.......................	24,183		9,879
Effect of Diluted Securities			
Stock options and restricted stock......................		86	
Shares held by benefit trust....	(8)	61	(194)
Earnings - Diluted..................	$24,175	17,308	$9,685

6. LONG-TERM DEBT

Our long-term debt consisted of the following:

	September 30, 2002	
	(In thousan	
9 3/8% Senior Subordinated Notes due 2010	$ 150,000	$
9 1/2% Senior Subordinated Notes due 2008	257,210	
9 1/2% Senior Subordinated Notes due 2006	2,367	
Bank credit facility (4.75% on September 30, 2002 and 3.71% on December 31, 2001)..	44,000	
Total debt...	453,577	
Interest rate swaps - fair value adjustment (Note 7)...............	990	
Interest rate swap - termination gain............................	11,956	
Long-term debt...	$ 466,523	$

7. FINANCIAL INSTRUMENTS

We have entered into commodity swaps, put options and interest rate swaps. The commodity swaps and put options are designated as cash flow hedges and the interest rate swaps are designated as fair value hedges in accordance with SFAS 133. Quantities covered by the commodity swaps and put options are based on West Texas Intermediate ("WTI") barrels. The average price realized per barrel from our production is expected to average 73% of the WTI price per barrel, therefore, each WTI barrel hedges approximately 1.38 barrels of our production.

Derivative Instruments Designated as Cash Flow Hedges.

At September 30, 2002, we had entered into the following cash flow hedges:

	WTI Crude Oil		Natur	
	Barrels Per Day	Average Price / Bbl	MMBTU Per Day	Ave Pr MM
Swaps (Selling at Fixed Price)				
Fourth quarter 2002	20,000	$ 24.87	12,000	$
First quarter 2003	17,500	24.32	--	
Second quarter 2003	14,500	23.85	--	
Third quarter 2003	13,500	23.62	--	
Fourth quarter 2003..................	11,500	23.50	--	
First quarter 2004...................	11,500	23.31	--	
Second quarter 2004..................	4,500	22.82	--	
Third quarter 2004...................	4,500	22.82	--	
Fourth quarter 2004..................	4,500	22.82	--	
First quarter 2005...................	4,500	22.14	--	
Second quarter 2005..................	4,500	22.14	--	
Third quarter 2005...................	4,500	22.14	--	
Fourth quarter 2005..................	4,500	22.14	--	
Put Options (Option Purchased)				
Fourth quarter 2002	9,000	$ 22.00		
WTI Crude Collars (Floor Purchased, Ceiling Sold)				
First quarter 2003...................	10,000	$ 22.00 - 28.91		
Second quarter 2003..................	10,000	22.00 - 28.91		
Third quarter 2003...................	10,000	22.00 - 28.91		
Fourth quarter 2003..................	10,000	22.00 - 28.91		

Natur	
MMBTU Per Day	Ave Pr MM

Swaps (Selling at Fixed Price)		
First quarter 2004..................	8,000	$
Second quarter 2004.................	8,000	
Third quarter 2004..................	8,000	
Fourth quarter 2004.................	8,000	
First quarter 2005..................	8,000	
Second quarter 2005.................	8,000	
Third quarter 2005..................	8,000	
Fourth quarter 2005.................	8,000	

Subsequent to September 30, 2002, we entered into the following cash flow hedges:

Natural Gas Collars (Floor Purchased, Ceiling Sold)		
First quarter 2003	6,000	$3.70 -
Second quarter 2003	6,000	3.70 -
Third quarter 2003	6,000	3.70 -
Fourth quarter 2003................	6,000	3.70 -

We recorded in oil and gas revenues a loss of $6.0 million related to our settled swaps in the third quarter of 2002. During the quarter ended September 30, 2002, our put options on 9,000 WTI Bbls/day expired and we recorded a loss of $1.1 million which is reflected in our statements of income as a reduction of revenue.

Derivative Instruments Designated as Fair Value Hedges.

We entered into three interest rate swap agreements with notional amounts totaling $200 million, to hedge a portion of the fair value of our 9 1/2% Notes due 2008 and our 9 3/8% Notes due 2010. During the nine months ended September 30, 2002, we recognized $4.9 million as a reduction of interest expense under these hedges. Under the terms of the agreements for the 9 3/8% Notes, the counterparty paid us a weighted average fixed annual rate of 9 3/8% on total notional amounts of $150 million, and we paid the counterparty a variable annual rate equal to the six-month and three-month LIBOR rate plus a weighted average rate of 3.49%. Under the terms of the agreement for the 9 1/2% Notes, the counterparty paid us a weighted average fixed annual rate of 9 1/2% on total notional amounts of $50 million, and we paid the counterparty a variable annual rate equal to the six-month LIBOR rate plus a weighted average rate of 3.92%.

On August 30, 2002, we terminated our swap transaction relating to the 9 3/8% Notes. As a result of this termination, we received accrued interest of $2.2 million and the present value of the swap option of $9.6 million. The gain of $9.6 million will be amortized as a reduction to interest expense over the life of the 9 3/8% Notes.

On September 6, 2002, we terminated the swap transaction on the 9 1/2% Notes and received $0.5 million in accrued interest and the present value of the swap option of $2.5 million. The gain of $2.5 million will be amortized as a reduction to interest expense over the life of the 9 1/2% Notes.

On August 30, 2002, we entered into a new interest rate swap agreement with a notional amount of $50 million, to hedge a portion of the fair value of our 9 3/8% Notes due 2010. This swap is designated as a fair value hedge and is reflected as an increase of long-term debt of $1.0 million as of September 30, 2002, with a corresponding increase in other long-term assets. In September 2002, we recorded $0.1 million as a reduction of interest expense. Under the terms of this agreement, the counterparty pays us a weighted average fixed annual rate of 9 3/8% on the total notional amount of $50 million and we pay the counterparty a variable annual rate equal to the six-month LIBOR rate plus a weighted average rate of 4.71%.

Derivative Instruments Not Designated as Hedges.

In December 2001, Enron Corp. ("Enron") and certain of its affiliates filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code. Once a deterioration in creditworthiness creates uncertainty as to whether the future cash flows from the hedging instrument will be highly effective in offsetting the hedged risk, the derivative instrument is no longer considered highly effective and no longer qualifies for hedge accounting treatment. At such time, the fair value of the derivative asset or liability is adjusted to its new fair value, with the change in value being charged to current earnings. The net gain or loss of the derivative instruments previously reported in other comprehensive income remains in accumulated other comprehensive income and is reclassified into earnings during the period in which the originally designated hedged items affect earnings. During the third quarter, $1.3 million was reclassified into revenue and at September 30, 2002, a deferred gain of $0.7 million remains in accumulated other comprehensive income and $0.4 million remains in deferred taxes related to the outstanding Enron options, which will be reclassified into earnings when the hedged production occurs during the remainder of 2002. In June 2002, we sold our Enron bankruptcy claim relating to these derivatives for $1.3 million, and due to the buyer's recourse under the terms of the agreement, it is reflected in long-term liabilities.

In 2001 and 2000, we entered into call spreads that terminate in December 2003, with the anticipation of using the proceeds to offset a contingent payment obligation to Unocal. Subsequent to entering into the call spreads, the market fell and as a result, offsetting call spreads were purchased to economically nullify the trade. All of our existing call spreads had been offset through the purchase of a mirror spread, however, the mirror call spread had been entered into with Enron and was cancelled in December 2001. The remaining mirror call spread is not designated as a hedging instrument and is marked-to-market with changes in fair value recognized currently in earnings. The fair value of the call spread decreased during the quarter ended September 30, 2002, and we recorded a loss of $0.5 million. At September 30, 2002, $2.4 million is reflected in other long-term liabilities.

With the acquisition of Athanor, we assumed two natural gas hedge positions. A swap of 20,000 MMBTU per month for the fourth quarter 2002 with a fixed NYMEX price of $2.52/MMBTU and a NYMEX to Permian basis swap at an average price spread of $0.18/MMBTU.

Included in derivative gain/loss in the third quarter is a $2.9 million derivative loss related to oil swap transactions that did not qualify for hedge accounting treatment. The swap transactions going forward will qualify for hedge accounting and will be accounted for as cash flow hedges.

8. SEGMENTS

Our operations are the exploration for and production of crude oil and natural gas. For segment reporting purposes, domestic producing areas have been aggregated as one reportable segment due to similarities in their operations as permitted by SFAS No. 131, Disclosures About Segments of an Enterprise and Related Information. Financial information by reportable segment is presented below:

	For the Quarter Ended September 30		
	Oil and Gas Domestic	Oil and Gas International	Other (1)
Revenues from external customers.............	$ 77,266	$ 10,854	$ 3,515
Operating income (loss) before income tax....	28,895	2,984	(21,953

	For the Quarter Ended September 30		
	Oil and Gas Domestic	Oil and Gas International	Other (1)
Revenues from external customers.............	$ 68,600	$ 12,422	$ 98
Operating income (loss) before income tax....	16,985	(24)	(21,499

	For the Nine Months Ended September		
	Oil and Gas Domestic	Oil and Gas International	Other (1)
Revenues from external customers.............	$ 222,288	$ 26,522	$ 3,56
Operating income (loss) before income tax....	88,980	9,128	(58,63

	For the Nine Months Ended September		
	Oil and Gas Domestic	Oil and Gas International	Other (1)
Revenues from external customers.............	$ 266,465	$ 26,148	$ 2
Operating income (loss) before income tax....	71,955	4,169	(63,9

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(1) Includes unallocated corporate expenses.

9. CONTINGENCIES AND OTHER MATTERS

On September 22, 2000, we were named as a defendant in the lawsuit Thomas Wachtell et al. versus Nuevo Energy Company in the Superior Court of Los Angeles County, California. We successfully removed this lawsuit to the United States District Court for the Central District of California. The plaintiffs, who own interests in the Point Pedernales properties, asserted numerous causes of action including breach of contract, fraud and conspiracy in connection with the plaintiffs' allegation that: (i) royalties had not been properly paid to them for production from the Point Pedernales field, (ii) payments had not been made to them related to production from the Pescado and Sacate fields and (iii) we had failed to recognize the plaintiffs interests in the Tranquillon Ridge project. We settled this lawsuit in June 2002 for, among other matters, making a payment to plaintiffs of $3.4 million, and receiving from plaintiffs certain interests in properties and extinguishing certain contract rights of plaintiffs. We established a reserve for this contingency in 2001 and the settlement payment did not have a material impact on our results of operations or financial position.

On April 5, 2000, we filed a lawsuit against ExxonMobil Corporation in the United States District Court for the Central District of California, Western Division. We and ExxonMobil each owned a 50% interest in the Sacate field, offshore Santa Barbara County, California. We believe that we had been denied a reasonable opportunity to exercise our rights under the unit operating agreement. We alleged that ExxonMobil's actions breached the unit operating agreement and the covenant of good faith and fair dealing. We settled this lawsuit in June 2002. Under the terms of the settlement agreement, we received $16.5 million from ExxonMobil and 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.

On September 14, 2001, during an annual inspection, we discovered fractures in the heat affected zone of certain flanges on our pipeline that connects the Point Pedernales field with onshore processing facilities. We voluntarily elected to shut-in production in the field while repairs were being made. The daily net production from this field was approximately 5,000 barrels of crude oil and 1.2 MMcf of natural gas, representing approximately 11% of our daily production. We replaced the damaged flanges, as well as others which had not shown signs of damage. We resumed production in January 2002. During the third quarter 2002 we reached a final agreement with our underwriters with respect to our business interruption claim. Accordingly, we recognized $3.0 million of business interruption recoveries during the third quarter 2002. Such amount is classified in other revenue and we expect to receive payment on this claim by the end of December 2002. Certain costs related to repair and business interruption are expected to be covered by insurance based on a tentative agreement we have with our underwriters. We expect payment with respect to the repair claims in the next twelve months once the claims are fully adjusted.

On June 15, 2001, we experienced a failure of a carbon dioxide treatment vessel at the Rincon Onshore Separation Facility ("ROSF") located in Ventura County, California. There were no injuries associated with this event. Crude oil and natural gas produced from three fields offshore California are transported onshore by pipeline to the ROSF plant where crude oil and water are separated and treated, and carbon dioxide is removed from the natural gas stream. The daily net production associated with these fields is 3,000 barrels of crude oil and 2.4 MMcf of natural gas, representing approximately 6% of our daily production. Crude oil production resumed in early July and full gas sales resumed by mid August. The cost of repair, less a $50,000 deductible, is expected to be covered by insurance. We expect to settle the insurance claims within the next nine months.

We have been named as a defendant in certain other lawsuits incidental to our business. These actions and claims in the aggregate seek damages against us and are subject to the inherent uncertainties in any litigation. We are defending ourselves vigorously in all such matters. We have reserved an amount that we deem adequate to cover any potential losses related to these matters to the extent the losses are deemed probable and estimable. This amount is reviewed periodically and changes may be made, as appropriate. Any additional costs related to these potential losses are not expected to be material to our operating results, financial condition or liquidity.

In September 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. The volume of the spill was estimated to be 163 Bbls of oil. Repairs were completed by the end of 1997, and production recommenced in December 1997. The costs of the clean up and the cost to repair the pipeline either have been or are expected to be covered by our insurance, less a deductible of $0.1 million. As of September 30, 2002, we had received insurance reimbursements of $4.2 million, with a remaining insurance receivable of $0.5 million. Costs related to the settlement of claims for natural resource damage asserted by certain federal and state agencies are also expected to be covered by insurance.

Our international investments involve risks typically associated with investments in emerging markets such as an uncertain political, economic, legal and tax environment and expropriation and nationalization of assets. In addition, if a dispute arises in our foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of the United States. We attempt to conduct our business and financial affairs to protect against political and economic risks applicable to operations in the various countries where we operate, but there can be no assurance that we will be successful in so protecting ourselves. A portion of our investment in the Congo is insured through political risk insurance provided by Overseas Private Investment Company ("OPIC"). The political risk insurance through OPIC covers up to $25.0 million relating to expropriation and political violence, which is the maximum coverage available through OPIC. We have no deductible for this insurance.

In connection with our February 1995 acquisitions of two subsidiaries owning interests in the Yombo field offshore Congo, we and a wholly-owned subsidiary of CMS NOMECO Oil & Gas Co. ("CMS") agreed with the seller of the subsidiaries not to claim certain tax losses ("dual consolidated losses") incurred by such subsidiaries prior to the acquisitions. Under the tax law in the Congo, as it existed when this acquisition took place, if an entity is acquired in its entirety and that entity has certain tax attributes, for example tax loss carryforwards from operations in the Republic of Congo, the subsequent owners of that entity can continue to utilize those losses without restriction. Pursuant to the agreement, we and CMS may be liable to the seller for the recapture of dual consolidated losses (net operating losses of any domestic corporation that are subject to an

income tax of a foreign country without regard to the source of its income or on a residence basis) utilized by the seller in years prior to the acquisitions if certain triggering events occur, including:

- a disposition by either us or CMS of its respective Congo subsidiary,

- either Congo subsidiary's sale of its interest in the Yombo field,
- the acquisition of us or CMS by another consolidated group or
- the failure of CMS's Congo subsidiary or us to continue as a member of its respective consolidated group.

A triggering event will not occur, however, if a subsequent purchaser enters into certain agreements specified in the consolidated return regulations intended to ensure that such dual consolidated losses will not be claimed. The only time limit associated with the occurrence of a triggering event relates to the utilization of a dual consolidated loss in a foreign jurisdiction. A dual consolidated loss that is utilized to offset income in a foreign jurisdiction is only subject to recapture for 15 years following the year in which the dual consolidated loss was incurred for U.S. income tax purposes. We and CMS have agreed among ourselves that the party responsible for the triggering event shall indemnify the other for any liability to the seller as a result of such triggering event. Our potential direct liability could be as much as $38.5 million if a triggering event with respect to us occurs. Additionally, we believe that CMS's liability (for which we would be jointly liable with an indemnification right against CMS) could be as much as $56.2 million. During the second quarter of 2002, we were notified by CMS that they have entered into an agreement to sell their interest in the Yombo field offshore Congo and that the transaction will be structured to avoid a triggering event. CMS closed the sale during the second quarter 2002 but is awaiting approval of the transaction from the government of Congo.

During 1997, a new government was established in the Congo. Although the political situation in the Congo has not to date had a material adverse effect on our operations in the Congo, no assurances can be made that continued political unrest in West Africa will not have a material adverse effect on us or our operations in the Congo in the future.

In 1996, the Congo government requested that the convention governing the Marine I Exploitation Permit be converted to a Production Sharing Agreement ("PSA"). We are under no obligation to convert to a PSA, and our existing convention is valid and protected by law. Our position is that any conversion to a PSA would have no detrimental impact to us, otherwise, we will not agree to any such conversion. Discussions with the government have been ongoing intermittently since early 1997. To date, no final agreement has been reached concerning conversion to a PSA.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS MERGER WITH ATHANOR RESOURCES, INC.

Effective September 18, 2002, pursuant to an Agreement and Plan of Merger, a wholly owned subsidiary of Nuevo Energy Company was merged with and into Athanor Resources, Inc. ("Athanor"), a Delaware corporation, and Athanor became the surviving wholly owned subsidiary of Nuevo Energy Company. In connection with the merger, Nuevo issued approximately 2.0 million shares of common stock for all of the common and preferred stock of Athanor. The results of Athanor's operations have been included in the consolidated financial statements effective September 18, 2002.

The merger was accounted for using the purchase method of accounting. The purchase price totaling approximately $101.4 million included a combination of $61.3 million of available cash and additional borrowings, the issuance of approximately $20.1 million of our common stock (approximately 2.0 million shares) to Athanor stockholders, and the assumption of net liabilities with a fair value of approximately $20.0 million.

The allocation of the purchase price resulted in approximately $21.7 million allocated to goodwill which is not expected to be deductible for tax purposes. This goodwill is attributable to a premium paid for Athanor because the acquisition gives Nuevo a new core area with increasing growth opportunities, diversifies our asset base with higher margin properties and was completed with a component of equity. Other accrued merger costs of $1.6 million include those capitalizable costs incurred to consummate the transaction, consisting primarily of professional fees. The allocation of the purchase price to specific assets and liabilities is based on certain estimates of fair values and costs which will be adjusted to actual amounts as determined.

RESULTS OF OPERATIONS

Our results of operations are significantly affected by fluctuations in oil and gas prices. Success in acquiring oil and gas properties and our ability to maintain or increase production through exploitation activities have also significantly affected our operating results. We sold our properties located in Texas, Louisiana and Alabama (Eastern properties) during the second and third quarters of 2002 and reflected the Eastern properties as discontinued operations in our financial statements. The following table reflects our production and average prices for oil and natural gas excluding the Eastern properties for all periods presented:

	Quarter Ended September 30,		Nine Month Septembe
	2002	2001	2002
Crude Oil and Liquids			
Sales Volumes (MBbls/d)			
Domestic................	38.5	38.3	39.6
International	4.9	6.2	5.1
Total	43.4	44.5	44.7
Sales Prices ($/Bbl)			
Unhedged	$21.15	$19.88	$18.66
Hedged	19.69	17.39	18.39
Revenues ($/thousands)			
Domestic	$73,900	$69,289	$202,090
International	12,198	12,754	29,563
Congo Earnout	(1,352)	(335)	(3,048)
Marketing Fees	(221)	(268)	(667)
Hedging	(5,849)	(10,177)	(3,326)
Total	$78,676	$71,263	224,612

	Quarter Ended September 30, 2002	Quarter Ended September 30, 2001	Nine Months September 2002
Natural Gas			
Sales Volumes (MMcf/d)			
Domestic	33.5	29.7	32.3
Sales Prices ($/Mcf)			
Unhedged	$3.07	$3.56	$2.74
Revenues ($/thousands)			
Domestic	$9,499	$9,909	$24,490
Marketing Fees	(55)	(150)	(292)
Total	$9,444	$9,759	$24,198

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 of crude oil or other liquid hydrocarbons
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
MMBTU	=	million British thermal units

QUARTER ENDED SEPTEMBER 30, 2002 COMPARED TO QUARTER ENDED SEPTEMBER 30, 2001

We had net income of $6.2 million, or $0.35 per diluted share for the quarter ended September 30, 2002 as compared to a net loss of $2.4 million, or $0.14 per diluted share in the same period of 2001.

Revenues

Oil and Gas Revenues. Oil and gas revenues of $88.1 million for the quarter ended September 30, 2002 increased 9% from $81.0 million in the same period of 2001 principally due to higher crude oil prices and lower hedging losses which was partially offset by lower oil production and lower natural gas prices. The realized oil price in the third quarter of 2002 was $19.69 per Bbl, an increase of $2.30 per Bbl from the same period in 2001. Crude oil production averaged 43.4 MBbls/day in the third quarter 2002, a decrease of 2% from the same period in 2001. The decreased production was due to lower production at Cymric and Congo due to downtime which was partially offset by higher production at Midway Sunset and Belridge which have responded to re-steaming. We had a hedging loss of $5.8 million in the third quarter of 2002 compared to a hedging loss of $10.2 million in same period of 2001. Natural gas production averaged 33.5 MMcf per day in the third quarter of 2002, an increase of 13% from the 2001 period of 29.7 MMcf per day primarily due to increased production onshore California. The realized natural gas price in the third quarter 2002 was $3.07 per Mcf, which decreased 14% from $3.56 per Mcf in the prior year period.

Other Revenue. During the third quarter of 2002 we reached a final agreement with our underwriters with respect to our business interruption claim (see Contingencies and Other Matters). Accordingly, we recognized $3.0 million of business interruption recoveries during the third quarter 2002. Such amount is classified in other revenue and we expect to receive payment on this claim by the end of December 2002.

Costs and Expenses

Costs and Expenses. Lease operating expenses ("LOE") for the quarter ended September 30, 2002 was $39.5 million, a slight decrease from the prior year period. Excluding the steam component, LOE decreased 10% in the third quarter of 2002 compared to the same period of 2001. Exploration costs were $2.3 million in the quarter ended September 30, 2002 compared to $5.8 million in the same period of 2001. The 2002 exploration costs included a $2.3 million write off of our Anaguid permit in Tunisia while the 2001 costs included $4.6 of dry hole costs. Depreciation, depletion and amortization ("DD&A") was $19.3 million in the third quarter of 2002 compared to $18.3 million in the prior year period. The DD&A rate was $4.27 per BOE in the 2002 period compared to $4.01 per BOE in 2001. General and administrative expense of $6.5 million in 2002 was $3.0 million lower than the comparable period in 2001 due to lower outsourcing costs, lower legal fees and lower project costs.

Derivative Gain (Loss). Our derivative loss of $3.4 million for the quarter ended September 30, 2002 is comprised of losses on our mark-to-market derivatives which are not accounted for as hedges.

Interest Expense. Interest expense of $9.5 million in the quarter ended September 30, 2002 decreased 10% compared to interest expense of $10.6 million in the same period of 2001. The decrease is primarily due to the benefit of our interest rate swaps in 2002 of $1.3 million.

Dividends. Dividends on the TECONS were $1.7 million in both quarters ended September 30, 2002 and 2001. The TECONS pay dividends at a rate of 5.75% and were issued in December 1996.

Income Tax. We had income tax expense of $4.0 million, including $1.0 million of current tax, in the quarter ended September 30, 2002 compared to a benefit of $1.8 million in the prior year period. Our effective income tax rate was 40.5% in 2002 and 40.3% in 2001.

YEAR TO DATE SEPTEMBER 30, 2002 COMPARED TO YEAR TO DATE SEPTEMBER 30, 2001

We had net income of $24.2 million, or $1.40 per diluted share for nine months ended September 30, 2002 as compared to net income of $9.9 million, or $0.57 per diluted share in the same period of 2001. Our net income for the nine months ended September 30, 2002 includes an after-tax gain of approximately $8.7 million related to the litigation settlement with ExxonMobil. Excluding this gain, our net income was $15.4 million, or $0.90 per diluted share.

Revenues

Oil and Gas Revenues. Oil and gas revenues decreased 15% to $248.8 million for the nine months ended September 30, 2002 from $292.6 million in the same period of 2001 due to significantly lower realized natural gas prices and lower oil production which was partially offset by lower hedging losses in 2002. Crude oil production averaged 44.7 MBbls/day for the nine months ended September 30, 2002 compared to 45.7 MBbls/day in the same period of 2001 primarily due to lower production offshore California due to mechanical downtime. The realized oil price for the nine months ended September 30, 2002 was $18.39 per Bbl, an increase of $2.20 per Bbl from the same period in 2001. We had hedging losses of $3.3 million in the nine months ended September 30, 2002 compared to hedging losses of $51.0 million in same period of 2001. Natural gas production averaged 32.3 MMcf per day for the nine months ended September 30, 2002 compared to 32.1 MMcf per day for the same period of 2001. The increase was primarily due to production from the Pakenham field which was acquired in September 2002. The realized natural gas price for the nine months ended September 30, 2002 was $2.74 per Mcf, which decreased 74% from $10.36 per Mcf in the comparable period in 2001.

Other Revenue. During the third quarter of 2002 we reached a final agreement with our underwriters with respect to our business interruption claim (see Contingencies and Other Matters). Accordingly, we recognized $3.0 million of business interruption recoveries during the third quarter 2002. Such amount is classified in other revenue and we expect to receive payment on this claim by the end of December 2002.

Costs and Expenses

Costs and Expenses. LOE for the nine months ended September 30, 2002 totaled $112.2 million, as compared to $145.4 million for the 2001 period. The 23% decrease in LOE is principally due to lower steam and workover costs in our California operations. Exploration costs were $3.8 million in the nine months ended September 30, 2002, a decrease from $13.0 million in the same period of 2001. Exploration costs in 2002 included a $2.3 million write off of our Anaguid permit in Tunisia while the 2001 costs included $6.5 million of dry hole costs and $5.0 million in seismic acquisitions. DD&A decreased to $56.3 million for the nine months ended September 30, 2002 primarily due to lower oil production. The DD&A rate was $4.11 per BOE in the 2002 period compared to $4.10 per BOE in 2001. General and administrative expense of $19.8 million in 2002 was $6.2 million lower than the comparable period in 2001 due to a $1.7 million severance payment in 2001 and lower legal fees, consulting fees and project costs. 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, 2002 is comprised of losses on our mark-to-market derivatives which are not accounted for as hedges of $4.1 million and $0.2 million of ineffectiveness on our hedges.

Interest Expense. Interest expense of $27.7 million for the nine months ended September 30, 2002 decreased 14% compared to interest expense of $32.2

million in the same period of 2001. The decrease is primarily due to the benefit of our interest rate swaps in 2002 of $5.0 million.

Dividends. Dividends on the TECONS were $5.0 million in both the nine months ended September 30, 2002 and 2001. The TECONS pay dividends at a rate of 5.75% and were issued in December 1996.

Income Tax. We had income tax expense of $16.0 million, including $1.0 million of current tax, for the nine months ended September 30, 2002 compared to an expense of $5.0 million in the prior year period. Our effective income tax rate was 40.5% in 2002 and 40.3% in 2001.

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CAPITAL RESOURCES AND LIQUIDITY

We have grown and diversified our operations through acquisitions of oil and gas properties and the subsequent exploitation and development of these properties. We have historically funded our operations and acquisitions with operating cash flows, bank financing, private and public placements of debt and equity securities, property divestitures and joint ventures with industry participants.

Net cash provided by operating activities was $67.5 million for the nine months ended September 30, 2002. In 2002, we invested $61.3 million for Athanor Resources, Inc., $37.6 million in oil and gas properties and $3.5 million on gas plant and other facilities. We also received $27.0 million in proceeds from the sale of properties in the nine months ended September 30, 2002.

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 2002. We have a $135 million borrowing base under our Credit Agreement. Under the most restrictive covenant, $135 million was available at September 30, 2002 of which we had drawn $44.0 million under the agreement. In August 2002, we issued a $0.8 million letter of credit under our Credit Agreement. We have an interest rate swap totaling $50 million on our 9 3/8 % Notes.

CONTINGENCIES AND OTHER MATTERS

On September 14, 2001, during an annual inspection, we discovered fractures in the heat affected zone of certain flanges on our pipeline that connects the Point Pedernales field with onshore processing facilities. We voluntarily elected to shut-in production in the field while repairs were being made. The daily net production from this field was approximately 5,000 barrels of crude oil and 1.2 MMcf of natural gas, representing approximately 11% of our daily production. We replaced the damaged flanges, as well as others which had not shown signs of damage. We resumed production in January 2002. During the third quarter of 2002 we reached a final agreement with our underwriters with respect to our business interruption claim. Accordingly, we recognized $3.0 million of business interruption recoveries during the third quarter of 2002. Such amount is classified in other revenue and we expect to receive payment on this claim by the end of December 2002. Certain costs related to repair and business interruption are expected to be covered by insurance based on a final agreement reached with our underwriters. We expect payment with respect to the repair claim in the next nine months once the claim is fully adjusted.

On June 15, 2001, we experienced a failure of a carbon dioxide treatment vessel at the Rincon Onshore Separation Facility ("ROSF") located in

Ventura County, California. There were no injuries associated with this event. Crude oil and natural gas produced from three fields offshore California are transported onshore by pipeline to the ROSF plant where crude oil and water are separated and treated, and carbon dioxide is removed from the natural gas stream. The daily net production associated with these fields is 3,000 barrels of crude oil and 2.4 MMcf of natural gas, representing approximately 6% of our daily production. Crude oil production resumed in early July and full gas sales resumed by mid August. The cost of repair, less a $50,000 deductible, is expected to be covered by insurance. We expect to settle the insurance claims within the next nine months.

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actions breached the unit operating agreement and the covenant of good faith and fair dealing. We settled this lawsuit in June 2002. Under the terms of the agreement, we received $16.5 million from ExxonMobil and 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 pre-tax gain related to the sale of this unproved property.

We have been named as a defendant in certain other lawsuits incidental to our business. Management does not believe that the outcome of such litigation will have a material adverse impact on our operating results, financial condition or liquidity above the amounts we have reserved to cover any potential losses. However, these actions and claims in the aggregate seek damages against us and are subject to the inherent uncertainties in any litigation. We are defending ourselves vigorously in all such matters.

In September 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. The volume of the spill was estimated to be 163 Bbls of oil. Repairs were completed by the end of 1997 and production recommenced in December 1997. The costs of the clean-up and the cost to repair the pipeline either have been or are expected to be covered by our insurance, less a deductible of $0.1 million. As of September 30, 2002, we had received insurance reimbursements of $4.2 million, with a remaining insurance receivable of $0.5 million. Costs related to the settlement of claims for natural resource damage asserted by certain federal and state agencies are also expected to be covered by insurance. We expect to settle the insurance claims within the next twelve months.

Our international investments involve risks typically associated with investments in emerging markets such as an uncertain political, economic, legal and tax environment and expropriation and nationalization of assets. In addition, if a dispute arises in our foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of the United States. We attempt to conduct our business and financial affairs so as to protect against political and economic risks applicable to operations in the various countries where we operate, but there can be no assurance that we will be successful in so protecting ourselves. A portion of our investment in the Congo is insured through political risk insurance provided by the Overseas Private Investment Corporation ("OPIC"). The political risk insurance through OPIC covers up to $25.0 million relating to expropriation and political violence, which is the maximum coverage available through OPIC. We have no deductible for this insurance.

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- a disposition by either us or CMS of its respective Congo subsidiary,
- either Congo subsidiary's sale of its interest in the Yombo field,
- the acquisition of us or CMS by another consolidated group or
- the failure of CMS's Congo subsidiary or us to continue as a member of its respective consolidated group.

A triggering event will not occur, however, if a subsequent purchaser enters into certain agreements specified in the consolidated return regulations intended to ensure that such dual consolidated losses will not be claimed. The only time limit associated with the occurrence of a triggering event relates to the utilization of a dual consolidated loss in a foreign jurisdiction. A dual consolidated loss that is utilized to offset income in a foreign jurisdiction is only subject to recapture for 15 years following the year in which the dual consolidated loss was incurred for U.S. income tax purposes. We and CMS have agreed among ourselves that the party responsible for the triggering event shall indemnify the other for any liability to the seller as a result of such triggering event. Our potential direct liability could be as much as $38.5 million if a triggering event with respect to us occurs. Additionally, we believe that CMS's liability (for which we would be jointly liable with an indemnification right against CMS) could be as much as $56.2 million. During the second quarter 2002, we were notified by CMS that they have entered into an agreement to sell their interest in the Yombo field offshore Congo and the transaction

will be structured to avoid a triggering event. CMS closed the sale during the second quarter 2002 but is awaiting approval of the transaction from the government of Congo.

During 1997, a new government was established in the Congo. Although the political situation in the Congo has not to date had a material adverse effect on our operations in the Congo, no assurances can be made that continued political unrest in West Africa will not have a material adverse effect on us or our operations in the Congo in the future.

In 1996, the Congo government requested that the convention governing the Marine 1 Exploitation Permit be converted to a Production Sharing Agreement ("PSA"). We are under no obligation to convert to a PSA, and our existing convention is valid and protected by law. Our position is that any conversion to a PSA would have no detrimental impact to us, otherwise, we will not agree to any such conversion. Discussions with the government have been ongoing intermittently since early 1997. To date, no final agreement has been reached concerning conversion to a PSA.

ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Accounting for Asset Retirement Obligations.

In August 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. This Statement requires companies to record a liability relating to the retirement and removal of assets used in their 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 are currently evaluating the effects of this pronouncement.

Accounting for Gains and Losses from Extinguishment of Debt.

In April 2002, the FASB issued SFAS No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections. This Statement rescinds SFAS No. 4, Reporting Gains and Losses from Extinguishment of Debt, which required all gains and losses from extinguishment of debt to be aggregated and, if material, classified as an extraordinary item, net of income taxes. As a result, the criteria in Accounting Principles Board Opinion (APB) 30 will now be used to classify those gains and losses. Any gain or loss on the extinguishment of debt that was classified as an extraordinary item in prior periods presented that does not meet the criteria in APB 30 for classification as an extraordinary item shall be reclassified. The provisions of this Statement are effective for fiscal years beginning after January 1, 2003.

Accounting for Costs Associated with Exit or Disposal Activities.

In July 2002, the FASB issued SFAS No. 146, Accounting for Costs Associated with Exit or Disposal Activities. This Statement requires the recognition of costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. The provisions of this Statement are effective for exit or disposal activities initiated after December 31, 2002.

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 are included throughout 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, 2001.

At September 30, 2002, we had entered into the following cash flow hedges:

	WTI Crude Oil		Natur	
	Barrels Per Day	Average Price / Bbl	MMBTU Per Day	Ave Pr MM
Swaps (Selling at Fixed Price)				
Fourth quarter 2002	20,000	$ 24.87	12,000	$
First quarter 2003	17,500	24.32	--	
Second quarter 2003	14,500	23.85	--	
Third quarter 2003	13,500	23.62	--	
Fourth quarter 2003.................	11,500	23.50	--	
First quarter 2004..................	11,500	23.31	--	
Second quarter 2004.................	4,500	22.82	--	
Third quarter 2004..................	4,500	22.82	--	
Fourth quarter 2004.................	4,500	22.82	--	
First quarter 2005..................	4,500	22.14	--	
Second quarter 2005.................	4,500	22.14	--	
Third quarter 2005..................	4,500	22.14	--	
Fourth quarter 2005.................	4,500	22.14	--	
Put Options (Option Purchased)				
Fourth quarter 2002	9,000	$ 22.00		
WTI Crude Collars (Floor Purchased, Ceiling Sold)				
First quarter 2003..................	10,000	$ 22.00 - 28.91		
Second quarter 2003.................	10,000	22.00 - 28.91		

Third quarter 2003..................	10,000	22.00 - 28.91		
Fourth quarter 2003.................	10,000	22.00 - 28.91		
Swaps (Selling at Fixed Price)				
First quarter 2004..................			8,000	$
Second quarter 2004.................			8,000	
Third quarter 2004..................			8,000	
Fourth quarter 2004.................			8,000	
First quarter 2005..................			8,000	
Second quarter 2005.................			8,000	
Third quarter 2005..................			8,000	
Fourth quarter 2005.................			8,000	

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Subsequent to September 30, 2002, we entered into the following cash flow hedges:

	Natur	
		A
	MMBTU Per Day	
Natural Gas Collars (Floor Purchased, Ceiling Sold)		
First quarter 2003	6,000	$3.7
Second quarter 2003	6,000	3.7
Third quarter 2003	6,000	3.7
Fourth quarter 2003.................	6,000	3.7

ITEM 4. DISCLOSURE CONTROLS AND PROCEDURES

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

The term "disclosure controls and procedures" is defined in Rule 13a-14(c) 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 under the Exchange Act is recorded, processed, summarized and reported within required time periods. Our Chief Executive Officer and our Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures as of a date within 90 days before the filing of the quarterly report, and they have concluded that as of that date, our disclosure controls and procedures were effective at ensuring that required information will be disclosed on a timely basis in our reports filed under the Exchange Act.

CHANGE IN INTERNAL CONTROLS

We maintain a system of internal controls that are designed to provide reasonable assurance that our books and records accurately reflect our transactions and that our established policies and procedures are followed. There were no significant changes to our internal controls or in other factors that could significantly affect our internal controls subsequent to the date of their evaluation by our Chief Executive Officer and our Chief Financial Officer, including any corrective actions with regard to significant deficiencies and material weaknesses.

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

- 2.1 Agreement and Plan of Merger dated September 18, 2002 by and among Athanor Resources, Inc., Athanor B.V., Nuevo Energy Company, Nuevo Texas Inc., Yorktown Energy Partners III, L.P., Yorktown Energy IV, L.P., Yorktown Partners LLC, SAFIC S.A., Charles de Mestral, J. Ross Craft, Montana Oil and Gas, Ltd., David A. Badley, James S. Scott, Glenn Reed, Doug Allison and Mohamed Yaich (Exhibit 2.1 to our Form 8-K dated September 19, 2002).

- 10.1 Registration Rights Agreement dated September 18, 2002 by and among Nuevo Energy Company, Yorktown Energy Partners III, L.P., Yorktown Energy IV, L.P., Yorktown Partners LLC, SAFIC S.A., Charles de Mestral, J. Ross Craft, Montana Oil and Gas, Ltd., David A. Badley, James S. Scott, Glenn Reed, Doug Allison and Mohamed Yaich (Exhibit 10.1 to our Form 8-K dated September 19, 2002).

- 10.2 Amendment to the 2001 Stock Incentive Plan (Exhibit 99.1 to our Form S-8 dated November 1, 2002).

(B) REPORTS ON FORM 8-K:

- We filed a current report on Form 8-K/A on September 24, 2002 amending the September 19, 2002 Form 8-K.

- We filed a current report on Form 8-K on September 19, 2002 announcing the acquisition of Athanor Resources, Inc.

- We filed a current report on Form 8-K on August 16, 2002 announcing the resignation of our Board member, David H. Batchelder.

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 8, 2002	By:	/s/ James L. Payne
			James L. Payne Chairman, President and Chief Executive Officer
Date:	November 8, 2002	By:	/s/ Janet F. Clark
			Janet F. Clark Senior Vice President and Chief Financial Officer

CERTIFICATION

I, James L. Payne, being the Chief Executive Officer, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Nuevo Energy Company;

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

(a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

(b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

(c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: November 8, 2002 By: /s/ James L. Payne

James L. Payne
Chairman, President and
Chief Executive Officer

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I, Janet F. Clark, being the Chief Financial Officer, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Nuevo Energy Company;

2. Based on my knowledge, this quarterly report does not contain any

untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

(a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

(b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

(c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: November 8, 2002 By: /s/ Janet F. Clark

Janet F. Clark
Senior Vice President and
Chief Financial Officer

EXHIBIT INDEX

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