NUEVO ENERGY CO
Form 10-Q
May 06, 2004

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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 March 31, 2004

OR

o **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 þ No o

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).
Yes þ No o

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 April 30, 2004: 20,407,599

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Computation of Earnings to Fixed Charges
Certification of CEO pursuant to Section 302
Certification of CFO pursuant to Section 302
Certification of CEO pursuant to Section 906
Certification of CFO pursuant to Section 906

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)

	Quarter Ended March 31,	
	2004	2003
Revenues		
Crude oil and liquids	$ 90,145	$ 82,802
Natural gas	13,647	15,310
Other	(944)	138
	102,848	98,250
Costs and Expenses		
Lease operating expenses	44,793	39,330
Exploration costs	366	1,072
Depletion, depreciation, amortization and accretion	18,678	17,389
General and administrative expenses	7,768	6,717
Other	910	795
	72,515	65,303
Operating Income	30,333	32,947
Derivative gain (loss)	(7,014)	(943)
Interest income	437	79
Interest expense	(4,219)	(9,322)
Interest on long-term liability to unconsolidated affiliate	(1,704)	
Loss on early extinguishment of debt	(3,004)	
Dividends on TECONS		(1,653)
Income From Continuing Operations Before Income Tax	14,829	21,108
Income Tax Expense		
Current	1,571	1,504
Deferred	6,080	6,941

	7,651	8,445
Income From Continuing Operations	7,178	12,663
Income from discontinued operations, including gain/loss on disposal, net of income tax	(37)	4,554
Cumulative effect of a change in accounting principle, net of income tax		8,496
Net Income	$ 7,141	$ 25,713
Earnings Per Share:		
Basic		
Income from continuing operations	$ 0.35	$ 0.66
Income from discontinued operations, net of income tax		0.24
Cumulative effect of a change in accounting principle, net of income tax		0.44
Net income	$ 0.35	$ 1.34
Diluted		
Income from continuing operations	$ 0.35	$ 0.65
Income from discontinued operations, net of income tax		0.24
Cumulative effect of a change in accounting principle, net of income tax		0.44
Net income	$ 0.35	$ 1.33
Weighted Average Shares Outstanding:		
Basic	20,246	19,199
Diluted	20,662	19,305

See accompanying notes.

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NUEVO ENERGY COMPANY

CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except share amounts)

	March 31, 2004	December 31, 2003
	(Unaudited)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 4,192	$ 6,276
Accounts receivable, net	53,333	39,729
Inventory	4,604	5,741
Assets held for sale	39,747	38,290
Deferred income taxes	20,822	11,906
Prepaid expenses and other	2,416	4,489
Total current assets	125,114	106,431
Property and equipment, at cost		
Land	5,224	5,224
Oil and gas properties (successful efforts method)	1,079,704	1,031,202
Other property	15,224	15,126
	1,100,152	1,051,552
Accumulated depreciation, depletion and amortization	(371,316)	(355,311)
Total property and equipment, net	728,836	696,241
Investment in affiliate	1,414	
Deferred income taxes	17,643	17,404
Goodwill	17,121	17,121
Other assets	8,420	7,779
Total assets	$ 898,548	$ 844,976
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Accounts payable	$ 66,807	$ 38,707
Accrued interest	6,343	3,663

Accrued drilling costs	5,251	5,568
Accrued lease operating costs	18,449	13,558
Price risk management activities	61,594	35,005
Other accrued liabilities	58,837	42,447
Total current liabilities	217,281	138,948
Long-term debt		
Senior subordinated notes	150,000	225,000
Bank credit facility	53,300	15,000
Long-term liability to unconsolidated affiliate	115,000	115,000
Total debt	318,300	355,000
Interest rate swaps fair value adjustment	2,276	(153)
Interest rate swaps termination gain	12,032	14,364
Long-term debt	332,608	369,211
Asset retirement obligation	105,111	102,921
Price risk management activities	19,327	10,512
Other long-term liabilities	72	1,555
Commitments and contingencies (Note 8)		
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, 23,189,228 and 23,151,781 shares issued and 20,385,227 and 19,682,494 shares outstanding, respectively	232	232
Additional paid-in capital	400,922	397,628
Treasury stock, at cost, 2,804,001 and 3,469,287 shares, respectively	(55,006)	(68,048)
Deferred stock compensation and other	(5,343)	(6,512)
Accumulated other comprehensive income (loss)	(43,862)	(24,614)
Accumulated deficit	(72,794)	(76,857)
Total stockholders equity	224,149	221,829
Total liabilities and stockholders equity	$ 898,548	$ 844,976

See accompanying notes.

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NUEVO ENERGY COMPANY

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)
(Unaudited)

	Quarter Ended March 31, 2004	Quarter Ended March 31, 2003
Cash flows from operating activities		
Net income	$ 7,141	$ 25,713
Adjustments to reconcile net income to net cash provided by operating activities		
Depletion, depreciation, amortization and accretion	18,678	17,389
Dry hole costs	7	571
Amortization of debt financing costs	270	633
Loss on early extinguishment of debt	3,004	
Deferred income taxes	6,080	6,941
Non-cash effect of discontinued operations	(18)	33
Cumulative effect of a change in accounting principle		(8,496)
Other	7,652	1,560
Working capital changes, net of non-cash transactions		
Accounts receivable	(13,510)	(18,896)
Accounts payable	(11,597)	(2,071)
Accrued liabilities	(1,574)	20,893
Other	(205)	2,864
Net cash provided by operating activities	15,928	47,134
Cash flows from investing activities		
Additions to oil and gas properties	(11,091)	(16,213)
Additions to other properties	(345)	(672)
Proceeds from sale of properties	24,502	65,406
Other investing activities		1,841
Net cash provided by investing activities	13,066	50,362
Cash flows from financing activities		
Payments of long-term debt	(75,000)	
Premium paid for redemption of notes	(3,563)	
Net borrowings (repayments) of credit facility	38,300	(28,700)

Proceeds from exercise of stock options	9,185	
Net cash used in financing activities	(31,078)	(28,700)
Increase (decrease) in cash and cash equivalents	(2,084)	68,796
Cash and cash equivalents		
Beginning of period	6,276	5,047
End of period	$ 4,192	$ 73,843

See accompanying notes.

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NUEVO ENERGY COMPANY

CONDENSED CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY
(In thousands)
(Unaudited)

	Quarter Ended March 31, 2004	
	Shares	**Amount**
Common Stock		
Balance, beginning of period	19,682	$ 232
Issuances and purchases of common stock		
Employee stock compensation and plans	703	
Balance, end of period	20,385	$ 232
Additional Paid-In Capital		
Balance, beginning of period		$397,628
Exercise of stock options		2,804
Employee stock compensation and plans		490
Balance, end of period		$400,922
Accumulated Deficit		
Balance, beginning of period		$ (76,857)
Loss on issue of treasury shares		(3,078)
Net income (loss)		7,141
Balance, end of period		$ (72,794)
Accumulated Other Comprehensive Income		
Balance, beginning of period		$ (24,614)
Other comprehensive income		(19,248)
Balance, end of period		$ (43,862)
Treasury Stock		
Balance, beginning of period		$ (68,048)

Issuance related to employee stock compensation and plans	13,042
Balance, end of period	$ (55,006)
Deferred Compensation and Other	
Balance, beginning of period	$ (6,512)
Deferred compensation	1,777
Stock acquired by benefit trust	(608)
Balance, end of period	$ (5,343)
Total Stockholders Equity	$224,149

See accompanying notes.

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NUEVO ENERGY COMPANY

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(In thousands)
(Unaudited)

	Quarter Ended March 31,	
	2004	**2003**
Net income	$ 7,141	$ 25,713
Unrealized gains (losses) from cash flow hedging activity:		
Reclassification adjustment for settled contracts	9,955	9,280
Changes in fair value of derivative instruments during the period	(29,203)	(12,936)
Other comprehensive income (loss)	(19,248)	(3,656)
Comprehensive income (loss)	$(12,107)	$ 22,057

See accompanying notes.

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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 United States 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 2003 Annual Report on Form 10-K, which includes a summary of our significant accounting policies and other disclosures. The financial statements as of March 31, 2004, and for the quarters ended March 31, 2004 and 2003, are unaudited. The balance sheet as of December 31, 2003, 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.

We have entered into a definitive agreement to be merged with Plains Exploration & Production Company (Plains) in a stock transaction valued at approximately $1 billion, based on Plains closing price on March 31, 2004. If completed, Plains will issue up to 37.5 million shares to our stockholders and assume $234 million of net debt (as of December 31, 2003) and $115 million of Trust Convertible Preferred Securities. Under the terms of the transaction, our stockholders will receive 1.765 shares of Plains common stock for each share of our common stock.

The transaction is expected to qualify as a tax free reorganization under Section 368(a) and is expected to be tax free to Plains stockholders and tax free for the stock consideration received by our stockholders. The Boards of Directors of both companies have approved the merger agreement and each has recommended it to their respective stockholders for approval. Consummation of the transaction is subject to shareholder approval from both companies at meeting on May 14, 2004, and other customary conditions.

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. No stock options were granted in the first quarter of 2004. As permitted by Statement of Financial Accounting Standards (SFAS) No. 123, *Accounting for Stock-Based Compensation*, we have continued to apply APB No. 25 for purposes of determining net income. In December 2002, the Financial Accounting Standards Board (FASB) issued SFAS No. 148, *Accounting for Stock-Based Compensation - Transition and Disclosure - an amendment of FASB Statement No. 123* to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. Additionally, the statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. 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:

	Quarter Ended March 31,	
	2004	**2003**
	(In thousands, except per share data)	
Net income as reported	$ 7,141	$ 25,713
Add:		
Stock based employee compensation expense included in reported net income, net of related income tax	570	178
Deduct:		
Total stock based employee compensation expense determined under fair value based method for all awards, net of related income tax	(710)	(225)
Pro forma net income	$ 7,001	$ 25,666
Earnings per share:		
Basic as reported	$ 0.35	$ 1.34
Basic pro forma	0.35	1.34
Diluted as reported	$ 0.35	$ 1.33
Diluted pro forma	0.34	1.33

Accounting for Costs Associated with Mineral Rights.

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 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.

The Emerging Issues Task Force has added the treatment of oil and gas mineral rights to an upcoming agenda which may result in a change in how we are currently classifying these costs. 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 at March 31, 2004 and $95 million at December 31, 2003, 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. Accounting for Asset Retirement Obligations.

SFAS No. 143, *Accounting for Asset Retirement Obligations* 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. 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.

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The following table rolls forward our asset retirement obligation in accordance with the provisions of SFAS No. 143:

	Quarter Ended March 31, 2004
	(In thousands)
Beginning asset retirement obligation	$ 102,921
Liabilities settled during period	(309)
Accretion expense	2,499
Ending asset retirement obligation	$ 105,111

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 ended March 31, 2004, we had 0.2 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 ended March 31, 2004, due to their anti-dilutive effect. The reconciliation is as follows:

	Quarter Ended March 31,			
	2004		2003	
	Net Income	Shares	Net Income	Shares
	(In thousands)			
Earnings - Basic	$7,141	20,246	$25,173	19,199
Effect of dilutive securities Stock options and restricted stock		416		106
Earnings - Diluted	$7,141	20,662	$25,713	19,305

4. Discontinued Operations

We 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:

	Quarter Ended March 31,	
	2004	**2003**
	(In thousands)	
Brea-Olinda		
Revenue	$	$ 3,245
Pre-tax (loss) income	(1)	2,598
Union Island		
Revenue		1,504
Gain/(loss) on disposition		7,725
Pre-tax income		1,325
Orcutt Hill		
Revenue		2,738
Gain/(loss) on disposition	(2)	(5,350)
Pre-tax (loss) income	(60)	1,288

On April 8, 2004, we entered into definitive agreements with Lankan Inc. and Perenco S.A. for the sale of the stock of our subsidiaries that hold our oil and gas interests in the Republic of Congo for $62.0 million, subject to working capital and other purchase price adjustments. These assets include a non-operating 50% working interest (37.5% revenue interest) in the Yombo field, a 50% interest in floating production, storage and off loading vessel, and a 50% interest in the Masseko field. The sale was approved by our Board of Directors and is subject to certain third party and governmental releases and consents. Closing of this sale is expected to be in the second or third quarter of 2004. These assets are included in continuing operations of our financial statements as the criteria for discontinued operations was reached subsequent to March 31, 2004.

5. Long-Term Debt

Our long-term debt consists of the following:

	March 31, 2004	December 31, 2003
	(In thousands)	
9 3/8% Senior Subordinated Notes due 2010	$150,000	$150,000
9½% Senior Subordinated Notes due 2008 [(1)].		75,000
Long-term liability to unconsolidated affiliate	115,000	115,000
Bank credit facility (2.16% at March 31, 2004, 2.02% at December 31, 2003)	53,300	15,000
Total debt	318,300	355,000
Interest rate swaps fair value adjustment	2,276	(153)
Interest rate swaps termination gain	12,032	14,364
Total long-term debt	332,608	$369,211

(1) Redeemed February 27, 2004

In February 2004, we redeemed the remaining $75.0 million of our 9½% Senior Subordinated Notes due 2008 for 104.75% of the principal amount plus accrued and unpaid interest. We recorded a $3.0 million loss on early extinguishment of debt consisting of a $3.6 million call premium, a $1.4 million write-off of deferred financing costs net of $2.0 million deferred gain relating to interest rate swaps.

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 82% of WTI, as reported on NYMEX, therefore, each WTI barrel hedges 1.22 barrels of our production. We have also entered into 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 March 31, 2004, we had recorded $43.7 million (net of related tax expense of $28.3 million) of hedging losses in other comprehensive income, of which $32.3 million (based on March 31, 2004 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 $17.0 million and $15.6 million in the first three months of 2004 and 2003, respectively, and lease operating expense was reduced by $0.9 million in the first three months of 2004. There was no hedging ineffectiveness for the first three months of 2004.

At March 31, 2004, we had entered into the following cash flow hedges:

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	Crude Oil				Natural Gas		
	Bbls / day	$ / Bbl		Index	MMbtu/day	$/MMbtu	Index
Swaps for Sales							
2004							
2nd Qtr	19,500	25.71		WTI	14,500	4.65	Waha & Socal
3rd Qtr	19,800	25.71		WTI	10,500	4.50	Waha & Socal
4th Qtr	21,000	25.98		WTI	14,500	4.64	Waha & Socal
2005							
1st Qtr	17,500	24.88		WTI	13,000	4.75	Waha & Socal
2nd Qtr	14,500	24.67		WTI	9,500	4.66	Waha
3rd Qtr	4,500	22.14		WTI	9,500	4.40	Waha
4th Qtr	4,500	22.14		WTI	9,500	4.40	Waha
Collars							
2005							
1st Qtr	4,300	$ 31.75	27.00	WTI			
2nd Qtr	6,800	30.40	27.00	WTI			
3rd Qtr	14,400	30.03	26.00	WTI			
4th Qtr	14,000	29.33	26.00	WTI			
Swaps for Purchases							
2004							
2nd Qtr – 4th Qtr					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 9½% Notes due 2008 and our 9 3/8% 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 3/8% Notes and $0.5 million in accrued interest and the present value of the swap option totaling $2.5 million on our 9½% Notes. The gain of $9.6 million on our 9 3/8% Notes and $2.5 million on our 9½% 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 March 31, 2004, we amortized $0.3 million as a reduction of interest expense, and $2.0 million as a reduction of loss on early extinguishment of debt on the 9½% Notes called February 2004.

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 3/8% 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 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 remaining gain of $4.1 million continues to be reflected as an increase of long-term debt and is being amortized as a reduction in interest expense over the life of the Notes. During the three months ended March 31, 2004, we amortized $0.1 million as a reduction of interest expense.

In late October 2003, we entered into an interest rate swap agreement with a notional amount of $100.0 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 in long-term debt of $2.3 million as of March 31, 2004, with a corresponding

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increase in long-term assets. Under the terms of the agreement, the counterparty pays us a weighted average fixed annual rate of 9 3/8% on total notional amount of $100.0 million, and we pay the counterparty a variable annual rate equal to the six-month LIBOR rate plus a weighted average rate of 5.02%.

Other Derivatives Not Designated as Hedging Instruments.

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 March 31, 2004, we recorded a $7.0 million derivative loss consisting of $3.0 million of settled contracts and $4.0 million of changes in fair value. The fair value of the derivative loss at March 31, 2004, totaling $8.1 million is recorded as a liability.

Three-Way Collars [1]	Bbls / day	Index	Weighted Average Price
2004			
(Apr Dec)	8,000	WTI	$19.28-24.00-31.00

(1) 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

Our operations consist of the acquisition, exploitation, exploration, development and production of crude oil and natural gas. We have four operating segments, Onshore California, Offshore California, West Texas and Congo because, in accordance with SFAS No. 131, these are the segments that (1) engage in business activities from which revenues are earned and expenses are incurred, (2) whose operating results are regularly reviewed by our chief operating decision maker to make decisions about resources to be allocated to the segment and assess its performance and (3) for which discrete financial information is available.

We have aggregated Onshore California, Offshore California and West Texas into our domestic segment, which is a reportable segment. We have aggregated these three operating segments because we believe these operating segments have similar economic characteristics in the following areas as outlined in SFAS No. 131: (1) the nature of the products and services, (2) the nature of the production process, (3) the type of class of customer for the products and services, (4) the methods used to distribute their products or provide their services and (5) the nature of the regulatory environment.

Our reportable segments are domestic, foreign and other. Financial information by reportable segment is presented below:

	Quarter Ended March 31, 2004			
	Domestic	Foreign[1]	Other[2]	Total
	(In thousands)			
Revenues	$92,882	$10,910	$ (944)	$102,848
	34,500	5,884	(25,555)	14,829

Income (loss) from continuing operations before income tax

	Quarter Ended March 31, 2003			
	Domestic	**Foreign[1]**	**Other[2]**	**Total**
	(In thousands)			
Revenues	$86,631	$11,481	$ 138	$98,250
Income (loss) from continuing operations before income tax	35,164	5,650	(19,706)	21,108

(1) We entered into a definitive agreement on April 8, 2004 to sell our Congo subsidiaries.

(2) Other includes corporate income and expenses.

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8. 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 believed were 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. We filed a 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 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 future deduction methodology and attorneys fees. On April 27, 2004, we entered into a formal settlement agreement with Unocal. We agreed to pay Unocal approximately $40.0 million to settle all past claims, buy out all future payments and to terminate the contingent payment obligation in its entirety. At March 31, 2004, the settlement is reported in accounts payable with a corresponding increase in oil and gas properties.

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.

Contingencies.

On April 8, 2004, we entered into definitive agreements with Lankan Inc. and Perenco S.A. for the sale of the stock of our subsidiaries that hold our oil and gas interests in the Republic of Congo for an estimated $62.0 million effective January 1, 2004, subject to working capital and other purchase price adjustments. The subsidiaries own assets that include a non-operating 50% working interest (37.5% revenue interest) in the Yombo field, a 50% interest in a floating production, storage and off loading vessel, and a 50% interest in the Masseko field. The Yombo field is located in the Marine 1 Permit 27 miles offshore the Republic of Congo in approximately 370 feet of water. Estimated net proved reserves of the Yombo field as of December 31, 2003 were 14.1 MMbl, and production during 2003 averaged 4.8 MBOE/day. The floating production storage and off loading vessel is a converted super tanker with storage capacity of over one million barrels, and our production is converted to No. 6 fuel oil with less than 0.3% sulfur content. The sale was approved by Nuevo s Board of Directors and is subject to certain third party and governmental releases and consents. Closing of this sale is expected to be in the second or third quarter of 2004.

Our acquisition agreement to purchase the two subsidiaries owning interests in the Yombo field offshore Congo contains a provision for a 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 estimate that we could reach payout as early as 2005. Upon consummation of the sale to Lankan Inc. and Perenco S.A., this obligation will be transferred to the purchasers.

By letter of March 23, 2004, the Republic of Congo has claimed it is entitled to reimbursement of certain sums deducted by the operator to offset Maritime taxes. Nuevo believes the claim is without merit and it is not expected to have a material impact on our results of operations, financial condition or liquidity.

In December 2003, we sold our Tonner Hills residential development property for approximately $47.0 million. We received $16.0 million of the purchase price on the date of the sale and received an additional $24.5 million in the first quarter of this year. We will receive another $6.5 million upon completion of certain habitat restoration activities. The $16.0 million and the $24.5 million are currently reported in other accrued liabilities, as these amounts are accounted for as deposits until the completion of the habitat restoration activities.

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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 March 31, 2004, we had surety bonds of $39.7 million and letters of credit of $1.9 million.

We have guaranteed the payment of the Nuevo Financing I TECONS issued December 1996. The TECONS are supported by our 5 3/4% Convertible Debentures, which are included in our balance sheet as long-term liability to unconsolidated affiliate.

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.

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

Proposed Merger with Plains Exploration & Production Company

On February 12, 2004, we entered into an agreement and plan of merger under the terms of which it is anticipated that we will be merged with Plains Exploration & Production Company (Plains) or alternatively become a wholly-owned subsidiary of Plains. Under the terms of the agreement, our stockholders will receive 1.765 shares of Plains common stock in exchange for each Nuevo common share. Following the merger, it is expected that our stockholders will own 48% of the combined company. The proposed merger is subject to approval by the stockholders of both companies at meetings on May 14, 2004, as well as other customary closing conditions.

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 consider an accounting estimate to be critical if (1) it requires assumptions to be made that were uncertain at the time the estimate was made; and (2) changes in the estimate or different estimates that could have been selected could have a material impact on our results of operations or financial condition. We believe the following critical accounting policies reflect our significant estimates and judgments used in the preparation of our financial statements:

Property, Plant and Equipment. 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 on a field basis. 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.

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.

Our rate of recording depreciation, depletion and amortization expense (DD&A) and our tests of impairment of proved properties are impacted by our estimation of proved reserves. There are numerous uncertainties in estimating crude oil and natural gas reserve quantities, projecting future production rates and projecting the timing of future development expenditures. Oil and gas reserve engineering must be recognized as a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way and estimates of other engineers might differ materially from those of Ryder Scott. The accuracy of any reserve estimate is a function of the quantity of available data and of engineering and geological interpretation and judgment. Accordingly, these estimates are subject to change as additional information becomes available.

We review our proved properties at the field level 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 impairment expense 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. 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.

Reduction in reserve estimates may result in increased DD&A expense and increased impairment of proved properties. Additionally, availability under our credit facility is determined in part by the present value of our oil and gas reserves based on our bankers assumptions regarding future prices, production, costs, risk factors and discount rates. If amounts outstanding under the credit facility exceed the borrowing base, we would be required to repay such excess over a period of time, which would affect our financial condition.

Goodwill. We recorded goodwill in connection with the purchase of Athanor. Goodwill was attributed to a premium paid for Athanor because the acquisition added a new core area with increasing growth opportunities, diversified our asset base with higher margin natural gas properties and was financed with a component of equity. SFAS No. 142 requires that goodwill of a reporting unit be tested for impairment annually at a reporting unit level. The reporting unit used to evaluate and measure goodwill for impairment is determined primarily from the manner in which the business is managed. A reporting unit is an operating segment or a component which is one level below an operating segment. A component is a reporting unit if the component constitutes a business for which discrete financial information is available and segment management regularly reviews the operating results of that component. However, two or more components of an operating segment shall be aggregated and deemed a single reporting unit if the components have similar economic characteristics. An operating segment is deemed to be a reporting unit if all of its components are economically similar.

We have identified four operating segments, Onshore California, Offshore California, West Texas and Congo. Components within these operating segments are oil and gas producing fields. We have determined that the oil and gas producing fields do not constitute individual businesses as they share exploration and production field personnel within their geographic area. Additionally, we believe that the components within each of our operating segments, the oil and gas producing fields, are economically similar as (1) the nature of the products and services, (2) the nature of the production process, (3) the type of class of customer for the products and services, (4) the methods used to distribute their products or provide their services and (5) the nature of the regulatory environment are similar. As a result, the goodwill has been assigned to the West Texas operating segment, which we consider to be a reporting unit. If the company were to reorganize or revise its manner of managing the assets, the reporting unit could change, and if the reporting unit were determined to be at a lower level, recognition of goodwill impairment may result that did not occur with the reporting unit at a higher level.

The fair value of each reporting unit that has goodwill is determined and compared to the carrying amount of the reporting unit. We determined the fair value of the reporting unit by comparing it to recent sales prices of similar oil and gas reserves. The selection of a valuation methodology and inputs to determine the fair value of the reporting unit require judgment, since we rely on oil and gas reserve reports are subject to changes as disclosed under property, plant and equipment. Changes to the valuation method, failure to replace oil and gas reserves at the same or better rate than they are produced, or decline in sales prices of oil and gas producing assets, could result in the impairment of goodwill. We performed our goodwill impairment test in the fourth quarter, which resulted in no impairment. We would also perform testing at interim dates upon the occurrence of significant events including potential impairment; a significant adverse change in legal factors or business climate; adverse action or assessment by a regulator; an more-like-than-not expectation that 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.

Asset Retirement Obligations. The computation of our asset retirement obligations was prepared in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations,* 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.

Our computation of asset retirement obligations requires us to make assumptions and judgments concerning whether we have a legal obligation, the settlement amount, timing of the settlement, inflation factors, credit adjusted discount rate and changes in the legal, regulatory, environmental and political environments. Estimating the future cost of asset retirement is difficult due to the long time period over which the costs will be incurred and the rapid changes in environmental law and technologies available for the removal of assets. 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 of 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 No. 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.

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The estimation of fair values for our hedging derivatives requires judgment. We estimate the fair values of our derivatives on a monthly basis using market-based quotes. The market-based quotes are compared to the prices fixed by the hedge agreements, and resulting estimated future cash inflows (outflows) over the lives of the hedges are discounted using our current borrowing rates under our revolving credit facility. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts, regional price differentials and interest rates. Currently, all of our derivative instruments are hedges of the price of crude oil and natural gas production and interest rates. We are not involved in any derivative trading activities.

SFAS No. 133 is complex and subject to interpretation in its application. In 1998, the FASB established the Derivative Implementation Group task force to consider and publish interpretations of issues arising from the implementation of FAS No. 133. As additional issues are reviewed, it is possible that interpretations could affect our method of accounting for derivatives, which could affect our results of operations and financial condition.

Income Taxes. Currently payable income taxes represent the liability related to our income tax return for the current year. Deferred income taxes, accounted for under the asset and liability method of accounting for 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. Our computation of deferred tax assets or liabilities includes determining whether the differences in the financial statement carrying amount and tax basis are permanent or temporary, the timing of the reversal of temporary differences and the statutory tax rate to be used. Changes in current tax laws and applicable statutory tax rates could affect the valuation of deferred tax assets and liabilities, impacting the income tax provisions. The effect on deferred taxes of a change in tax rates is recognized in income in the period the change occurs. In late 2003, we became a current taxpayer in Congo.

We periodically assess, by tax jurisdiction, the ability to realize recorded deferred tax assets based on our assessment of future earnings outlook. Significant declines in taxable income could materially impact the realizable value of deferred tax assets.

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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 and Orcutt Hill field in 2003. 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:

	Quarter Ended March 31,	
	2004	**2003**
Crude Oil and Liquids		
Sales Volumes (MBbls/day)		
Domestic	36.9	37.2
Foreign [1]	4.7	4.9
Total	41.6	42.1
Sales Prices ($/Bbl)		
Unhedged	$ 28.27	$ 25.51
Hedged	23.83	21.83
Revenues ($/thousands)		
Domestic	$ 96,020	$ 85,271
Foreign [1]	10,910	11,481
Marketing Fees		(4)
Hedging	(16,785)	(13,946)
Total	$ 90,145	$ 82,802
Natural Gas		
Sales Volumes (MMcf/day)		
Domestic	35.2	39.4
Sales Prices ($/Mcf)		
Unhedged	$ 4.35	$ 4.80
Hedged	4.26	4.32
Revenues ($/thousands)		
Domestic	$ 13,953	$ 17,106
Marketing Fees	(43)	(93)
Hedging	(263)	(1,703)

Total	$ 13,647	$ 15,310

(1) We entered into a definitive agreement on April 8, 2004 to sell our Congo subsidiaries. Included in oil revenues are revenues from Congo for the quarter ended March 31, 2004 of $10.8 million and volumes of 4.6 MBbls/day.

Quarter Ended March 31, 2004 Compared to Quarter Ended March 31, 2003

We reported net income and income from continuing operations of $7.2 million, or $0.35 per diluted share for the quarter ended March 31, 2004 as compared to net income of $25.7 million, or $1.33 per diluted share and income from continuing operations of $12.7 million, or $0.65 per diluted share in the same period of 2003. Income from continuing operations is discussed below.

Revenues.

Oil and Gas Revenues. Oil revenue of $90.1 million for the quarter ended March 31, 2004 increased $7.3 million from $82.8 million in the same period of 2003 due to higher crude oil prices which was partially offset by lower crude oil production and higher hedging losses in 2004. The realized oil price for the quarter ended March 31, 2004, was $23.83 per Bbl, compared to $21.83 per Bbl from the same period in 2003. Crude oil production decreased to 41.6 MBbls/day for the quarter ended March 31, 2004 from 42.1 MBbls/day in the same period of 2003 primarily due to production declines onshore California partially offset by the acquisition of an additional interest in the Point Pedernales field offshore California. We had crude oil hedging losses of $16.8 million, or $4.44 per Bbl in the quarter ended March 31, 2004 compared to hedging losses of $13.9 million, or $3.68 per Bbl in same period of 2003. Natural gas production averaged 35.2 MMcf per day for the quarter ended March 31, 2004, a decrease of 4.2 MMcf per day from the same period of 2003. Decreased natural gas production during the quarter ended March 31, 2004, is due to production decline on our Pitas Point offshore California and lower production at our Pakenham field due to the decline of a prolific well brought on line in the first quarter 2003. The realized natural gas price for the quarter ended March 31, 2004, was $4.26 per Mcf, compared to $4.32 per Mcf from the comparable period in 2003. We had natural gas hedging losses of $0.3 million, or $0.09 per Mcf in the quarter ended March 31, 2004, compared to hedging losses of $1.7 million, or $0.48 per Mcf in the same period of 2003.

Other Revenue. Other revenue was $(0.9) million in the quarter ended March 31, 2004, compared to $0.1 million in the same period of 2003. The 2004 period included $1.5 million related to the completion of a sale of our Enron claim to a third party.

Costs and Expenses.

	Quarter Ended March 31,		Variance	
	2004	**2003**	**Amount**	**Percentage**
Lease operating expenses[(1)]	$44,793	$39,330	$5,463	14%
Exploration costs	366	1,072	(706)	(66)
Depletion, depreciation, amortization and accretion	18,678	17,389	1,289	7
General and administrative	7,768	6,717	1,051	16
Other	910	795	115	15
	$72,515	$65,303	$7,212	11%
Lease Operating Expense per BOE	$ 10.38	$ 8.97	$ 1.41	16%
Domestic	10.63	9.24	1.39	15
International	8.06	6.56	1.50	23

(1) We entered into a definitive agreement on April 8, 2004 to sell our Congo subsidiaries. LOE from the Congo assets was $3.4 million for the quarter ended March 31, 2004.

Costs and Expenses. Lease operating expense (LOE) for the quarter ended March 31, 2004, was $44.8 million, compared to $39.3 million in the 2003 period. The increased LOE is due to higher steam costs in our onshore California operations due to higher natural gas prices for gas purchased and increased volumes burned, higher major maintenance expense in our onshore and offshore California operations and the acquisition of an additional interest in

Point Pedernales. Depletion, depreciation, amortization and accretion (DD&A) of $18.7 million for the quarter ended March 31, 2004, was $1.3 million higher than the same period of 2003 principally due to additional depletion expense associated with the basis added related to the settlement with Unocal. General and administrative costs increased to $7.7 million in the quarter ended March 31, 2004, from $6.7 million in the same period of 2003 due to higher legal fees related to the Unocal lawsuit and costs related to the merger with Plains Exploration & Production Company.

Derivative Gain (Loss). The derivative loss was $7.0 million for the quarter ended March 31, 2004, compared to $0.1 million in the same period of 2003. The derivative loss is comprised of realized and unrealized losses on our mark-to-market derivatives which are not accounted for as hedges.

Interest Expense. Interest expense decreased 55% to $4.2 million for the quarter ended March 31, 2004, compared to $9.3 million in the same period of 2003. Lower interest expense of $5.0 million results from the redemption of $259.6 million of 9 1/2% Notes during the twelve months ended March 31, 2004.

Loss on Early Extinguishment of Debt. During the quarter ended March 31, 2004, we repaid the remaining $75.0 million of our 9 1/2% Senior Subordinated Notes due in 2008 and paid a premium of $3.6 million to call the Notes prior to their maturity. Additionally, we expensed the unamortized financing costs of $1.4 million and recognized the deferred gain relating interest rate swaps of $2.0 million.

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Interest on Long-Term Liability To Unconsolidated Affiliate. Interest on Debentures was $1.7 million in the quarter ended March 31, 2004. The Debentures pay interest at 5¾%.

Dividends. Dividends on the TECONS were $1.7 million in the quarter ended March 31, 2003. The TECONS pay dividends at a rate of 5.75%. As a result of our implementation of FIN46R, *Consolidation of Variable Interest Entities*, on December 31, 2003, we deconsolidated the Nuevo Financing I Business Trust, which issued our TECONS

Income Tax. We had income tax expense of $7.7 million including current tax expense of $1.6 million for the quarter ended March 31, 2004, compared to an expense of $8.4 million in the prior year period. Our effective income tax rate was 51.6% in 2004 and 40.0% in 2003. The increase in our effective tax rate is due to becoming a current taxpayer in Congo late in 2003.

Discontinued Operations. We had income from discontinued operations, net of taxes, for the quarter ended March 31, 2003, of $4.6 million. In 2003, we sold our Brea-Olinda, Union Island and Orcutt Hill properties located onshore California.

Capital Resources and Liquidity

Our principal requirements for cash, other than working capital needs for existing operations, are costs of development of oil and gas properties, retirement of higher cost debt and the acquisition of oil and gas properties. We have historically funded our development program, debt repayments and acquisitions with cash flow from operations, bank financing, public and private placements of debt and equity securities, property divestitures and joint ventures with industry participants. We believe that our liquidity and capital resources are sufficient to meet our obligations.

At March 31, 2004, our current liabilities exceeded our current assets due primarily to the mark-to-market on our price risk management activities, which resulted in a current liability of $61.6 million. We anticipate paying our hedging liability with cash from operations.

Cash flow

	Quarter Ended March 31,	
	2004	2003
	(In thousands)	
Net cash provided by operating activities	$ 15,928	$ 47,134
Net cash provided by investing activities	13,066	50,362
Net cash used in financing activities	(31,078)	(28,700)

Quarter Ended March 31, 2004 Compared to Quarter Ended March 31, 2003

Operating cash flow decreased to $15.9 million in the first quarter 2004 due to working capital changes related to Congo liftings, derivative settlements and payments made in the first quarter 2004.

We generated $13.1 million of cash flow from investing activities during the quarter ended March 31, 2004, as a result of receiving an additional payment on the Tonner Hills sale of $24.5 million. During the same period in 2003, we sold our Brea Olinda and Union Island fields for $65.4 million, net of purchase price adjustments. Additionally, less cash was used in additions to oil and gas properties as management continues to contain costs and be selective in spending.

Cash used in financing activities was $31.1 million in the quarter ended March 31, 2004 , and included $78.6 million due to the redemption of our 9 1/2% Senior Subordinated Notes due 2008 which was partially offset by an increase in bank debt of $38.3 million and proceeds from the issuance of common stock of $9.2 million. During the same period of 2003, bank debt was reduced $28.7 million.

Asset Dispositions. Proceeds from asset dispositions were $24.5 million and $65.4 million during the quarter ended March 31, 2004 and 2003, as management has actively sought buyers for our non-core and marginal assets. In 2004, we received an additional payments on the Tonner Hills sale. In 2003, we sold two non-core oil and gas properties in California; Brea-Olinda ($59.0 million) and Orcutt Hill ($12.9 million).

We disposed of our Tonner Hills residential development property for approximately $47 million in December 2003. We received $16.0 million of the purchase price on the sale date and an additional $24.5 million in the first quarter 2004. We included these amounts in other current liabilities as a deposit related to the purchase. The remaining $6.5 million will be received by us once we have completed certain habitat restoration. Because of the continuing involvement with Tonner Hills, we have not recorded this transaction as a sale in 2004. We currently have assets held for sale of approximately $38.3 million including $36.3 million related to Tonner Hills and $2.0 million related to parcels of real estate in California which we expect to sell in 2004.

On April 8, 2004, we entered into a definitive agreement to sell our Congo subsidiaries for an estimated $62.0 million to be reduced by purchase price adjustments. This sale is expected to close in the second or third quarter of 2004, and use of the proceeds will be determined at that time.

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Credit Facility

Our bank credit facility provides for secured revolving credit availability including issuance of letters of credit of up to $250.0 million from a bank group led by Bank of America, NA; Bank One, NA and Bank of Montreal, and expires on June 7, 2005. At March 31, 2004, we had $53.3 million outstanding under the Credit Facility and two letters of credit outstanding in the amount of $1.9 million. Amounts borrowed under the credit facility bear interest at a rate of 2.2%.

Availability under the Credit Facility is determined pursuant to a semi-annual borrowing base determination which establishes the maximum borrowings that may be outstanding under the Credit Facility. The borrowing base is determined by a 60% vote of participant banks (two-thirds in the event of an increase in the borrowing base), each of which bases its judgment on: (i) the present value of our oil and gas reserves based on their own assumptions regarding future prices, production, costs, risk factors and discount rates, and (ii) projected cash flow coverage ratios calculated under varying scenarios. If amounts outstanding under the Credit Facility exceed the borrowing base, as redetermined from time to time, we would be required to repay such excess over a defined period of time. We have a $250.0 million borrowing base under our Credit Facility with $194.8 million available at March 31, 2004.

Our Credit Agreement has covenants which limit certain restricted payments and investments, guarantees and indebtedness, prepayments of subordinated and certain other indebtedness, mergers and consolidations, on certain types of acquisitions and on the issuance of certain securities by subsidiaries, liens, sales of properties, transactions with affiliates, derivative contracts and debt in subsidiaries. We are also required to maintain certain financial ratios and conditions, including without limitation, an EBITDAX to fixed charge coverage ratio and a funded debt to capitalization ratio. At March 31, 2004, we were in compliance with all covenants of the Credit Agreement.

EBITDAX to fixed charge coverage ratio. At March 31, 2004, based on bank covenants, the EBITDAX to fixed charge coverage ratio was 5.4x, compared to 4.1x in 2003. Our Credit Agreement requires the EBITDAX to fixed charge coverage ratio to be 2.0x at March 31, 2004.

Funded debt to capitalization ratio. At March 31, 2004, based on bank covenants, total capitalization is approximately $606 million, consisting of approximately $203 million of debt and approximately $402 million of equity, resulting in a debt to capitalization ratio of 34% compared to 53% in 2003. The improvement in our debt to capitalization ratio is due to the repayment of approximately $257 million of our 9½% Senior Subordinated Notes due 2008 and approximately $2 million of our 9½% Senior Subordinated Notes due 2006.

Senior Subordinated Notes

At March 31, 2004 we had $150.0 million outstanding of our 9 3/8% Senior Subordinated Notes due October 1, 2010. The 9 3/8% Senior Subordinated Notes are redeemable, in whole or in part, at our option, on or after October 2005, under certain conditions. We are not required to make mandatory redemption or sinking fund payments with respect to these Notes. The indenture contains covenants that, among other things, limit our ability to incur additional indebtedness, limit restricted payments, limit issuances and sales of capital stock by restricted subsidiaries, limit dispositions of proceeds from asset sales, limit dividends and other payment restrictions affecting restricted subsidiaries, and restrict mergers, consolidations or sales of assets.

Long-term Liability to Unconsolidated Affiliate

In December 1996, we issued $115.0 million of 5¾% Convertible Subordinated Debentures due December 15, 2026, which were issued to Nuevo Financing I Business Trust, a wholly owned subsidiary, to facilitate the offering of the TECONS. Interest on these Debentures accrues at 5¾% per annum and is payable quarterly on March 15, June 15, September 15 and December 15. The Debentures are redeemable, in whole or in part, at our option, upon not less than 30 or more than 60 days notice, on or after December 15, 1999, under certain conditions. We are required to redeem the Debentures at 100% in the event of a tax or legal structure change as defined in the agreement. The holder of the Debentures has the right, exercisable at any time prior to the close of business on December 15, 2026, to convert the principal amount into shares of our common stock at a conversion rate of 0.8421 shares for each Debenture, subject to adjustment under certain circumstances. We are not required to make sinking fund payments with respect to the Debentures.

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Interest Rate Swap

During the fourth quarter of 2003, we entered into an interest rate swap agreement with a notional amount of $100.0 million, to hedge a portion of the fair value of our 9 3/8% Senior Subordinated Notes due 2010. This swap is designated as fair value hedge and is reflected as an increase in long-term debt of $2.3 million as of March 31, 2004, with a corresponding increase in long-term assets. Under the terms of the agreement, the counterparty pays us a weighted average fixed annual rate of 9 3/8% on total notional amount of $100.0 million, and we pay the counterparty a variable annual rate equal to the six-month LIBOR rate plus a weighted average rate of 5.02%.

Common Stock

Our Board of Directors has authorized the issuance of up to 50.0 million shares, and at March 31, 2004, we had approximately 23.2 million shares issued and 20.4 million shares outstanding.

Our Board of Directors has authorized the open market repurchase of up to 5.6 million shares of common stock. Repurchases may be made at times and at prices deemed appropriate by management and consistent with the authorization of our Board. There were no shares repurchased in 2004. As of March 31, 2004, we had 2.8 million shares of treasury stock.

Joint Venture Formation The exploration and development of oil and gas reserves requires substantial capital expenditures. In order to reduce our investment in a particular project, we may form joint ventures and seek joint venture partners to share the costs.

Contractual Cash Obligations

The following table summarizes our contractual cash obligations by payment due date:

	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
			(In thousands)		
Long-term debt	$265,000	$	$	$	$265,000
Operating leases	5,852	1,487	2,682	1,616	67
Capital commitments	4,520	320	4,200		
Asset retirement obligation	105,111	2,451	17,008	40,429	45,223
Total contractual cash obligation	$380,483	$4,258	$23,890	$42,045	$310,290

Contingencies and Other Matters

See Item 1, Financial Statements, Note 8, which is incorporated herein by reference.

New Accounting Pronouncements

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

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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 2, 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 and 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.

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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, 2003.

At March 31, 2004, 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						
2004						
2nd Qtr	19,500	25.71	WTI	14,500	4.65	Waha & Socal
3rd Qtr	19,800	25.71	WTI	10,500	4.50	Waha & Socal
4th Qtr	21,000	25.98	WTI	14,500	4.64	Waha & Socal
2005						
1st Qtr	17,500	24.88	WTI	13,000	4.75	Waha & Socal
2nd Qtr	14,500	24.67	WTI	9,500	4.66	Waha
3rd Qtr	4,500	22.14	WTI	9,500	4.40	Waha
4th Qtr	4,500	22.14	WTI	9,500	4.40	Waha
Collars						
2005						
1st Qtr	4,300	$ 31.75 27.00				
2nd Qtr	6,800	30.40 27.00				
3rd Qtr	14,400	30.03 26.00				
4th Qtr	14,000	29.33 26.00				
Swaps for Purchases						
2004						
2nd Qtr 4th Qtr				8,000	3.91	Socal
2005				8,000	3.85	Socal

Derivatives Not Designed as Hedges

	Crude Oil		
Three-Way Collars (1)	**Bbls / day**	**Index**	**Weighted Average Price**
2004			
(Apr Dec)	8,000	WTI	$ 19.28 24.00 31.00

(1) 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.

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.

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PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

See Part I, Item 1, Financial Statements, Note 8, 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:

10.01	Stock Purchase Agreement dated April 6, 2004, by and between Perenco S.A., Lankan Inc., Nuevo Energy Company and Nuevo International Inc. (Exhibit 10.01 to our Form 8-K filed on April 20, 2004).
10.02	Stock Purchase Agreement dated April 6, 2004, by and between Perenco S.A., Nuevo Energy Company and Nuevo International Inc., (Exhibit 10.02 to our Form 8-K filed on April 20, 2004).
10.03	Agreement and Plan of Merger, dated February 12, 2004, by and between Nuevo Energy Company and Plains Exploration & Production Company and PXP California Inc., (Exhibit 2.1 to our Form 8-K filed on February 12, 2004).
12.1	Computation of Earnings to Fixed Charges and Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends
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

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(b) Reports on Form 8-K

Date	Event Reported
April 28, 2004	Press release announcing the buyout of a contingent payment with Unocal
April 20, 2004	Pro forma financial statements and exhibits regarding sale of Nuevo Congo subsidiaries
April 8, 2004	Press release announcing sale of Nuevo Congo subsidiaries
March 5, 2004	Press release announcing the appointment of Chief Financial Officer
March 4, 2004	Press release announcing Fourth Quarter 2003 Earnings
February 12, 2004	Press release announcing the Agreement and Plan of Merger with Plains Exploration & Production Company
January 28, 2004	Press release announcing final redemption of 9 ½% Senior Subordinated Notes
January 5, 2004	Press release announcing completion of sale of California real estate properties
January 5, 2004	Press release announcing the significant increase in realized pricing for California crude oil production

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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: May 6, 2004	By: /s/ James L. Payne
	James L. Payne *Chairman, President and* *Chief Executive Officer*
Date: May 6, 2004	By: /s/ Michael S. Wilkes
	Michael S. Wilkes *Chief Financial Officer*

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