NUEVO ENERGY CO
Form 10-K
March 31, 2003

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

FORM 10-K

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

FOR THE FISCAL YEAR ENDED DECEMBER 31, 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

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of each class	Name of each exchange on which re
Common Stock, par value $.01 per share	New York Stock Exchange
$2.875 Term Convertible Securities, Series A	New York Stock Exchange
Preferred Stock Purchase Rights	New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT: NONE

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 by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this

Form 10-K. [ ]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b.2 of the Act). Yes [X] No [ ].

THE AGGREGATE MARKET VALUE OF THE VOTING STOCK HELD BY NON-AFFILIATES OF THE REGISTRANT:

As of March 24, 2003, the aggregate market value of the voting stock of the registrant held by non-affiliates of the registrant was approximately $244.9 million.

As of June 28, 2002, the aggregate market value of the voting stock of the registrant held by non-affiliates of the registrant was approximately $270.1 million.

THE NUMBER OF SHARES OUTSTANDING OF EACH OF THE REGISTRANT'S CLASSES OF COMMON STOCK AS OF THE LATEST PRACTICABLE DATE:

As of March 24, 2003, number of shares of Common Stock outstanding: 19,209,290.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the registrant's annual proxy statement, to be filed within 120 days after December 31, 2002, are incorporated by reference into Part III.

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PART I

ITEM 1. BUSINESS

GENERAL

Nuevo Energy became a public company in 1990 and is engaged in the acquisition, exploitation, exploration, development and production of crude oil and natural gas. Our core areas in the U.S. are onshore and offshore California and West Texas. We also have international crude oil production in the Republic of Congo.

We are the largest independent oil and gas exploration and production company in California. At year-end 2002, approximately 87% of our proved reserves were in California (63% onshore and 24% offshore) which have a long reserve life and shallow production decline curves. Our California production was approximately 88% of our 2002 oil and gas production. The high asset concentration combined with a high proportion of operated properties enables us to control the timing of exploitation and development expenditures.

In September 2002, we created a new core area in West Texas with approximately 100 Bcfe of natural gas reserves through the acquisition of Athanor Resources, Inc. ("Athanor"). In 2002, approximately 11% of our natural gas production was from West Texas and it accounted for 6% of our proved reserves and 39% of our proved natural gas reserves at year-end 2002. As a result of the acquisition, we are the operator of the Pakenham field, which has significant exploitation and exploration inventory.

Our only international producing property is offshore the Republic of Congo, which had approximately 7% of our proved reserves at year-end 2002. This property is non-operated and provides a stable production profile with 10% of our 2002 production.

We achieved significant objectives in 2002 from an operational and financial perspective. We terminated outsourcing contracts and now manage our field operations, oil marketing, human resources, accounting, treasury and land administration. We implemented cost reduction measures which were successful in lowering lease operating costs 17%, lowering exploration costs 79%, lowering general and administrative costs 30% and lowering interest expense 12%. A disciplined capital allocation resulted in a 58% reduction of capital additions to oil and gas properties excluding acquisitions, while increasing oil and gas production. After completing a $101.4 million acquisition in 2002, we reduced debt and increased liquidity by year-end.

In 2003 we will continue to maintain our strategy of disciplined allocation of capital, continued cost reductions throughout the organization, monetization of non-core assets, diversification of our asset base and the strengthening of our balance sheet.

Our annual report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K are made available on our website at www.nuevoenergy.com.

As used in this annual report, the words "we", "our", "us", "Nuevo" and the "Company" refer to Nuevo Energy Company, except as otherwise specified, and to our subsidiaries.

RESERVES

The following table details our estimated proved reserves at December 31, 2002:

	Net Proved Reserves		
	Crude Oil And Liquids (MBbls)	Natural Gas (MMcf)	MBOE
U.S. Properties			
California Fields			
Cymric	77,273	4,847	78,08
Midway-Sunset	22,257	--	22,25
Point Pedernales	15,795	2,693	16,24
South Belridge	14,732	2,331	15,12
Santa Clara	10,489	15,163	13,01
Dos Cuadras	9,419	5,978	10,41
Buena Vista	2,554	21,346	6,11
Other	20,605	42,952	27,76
Total California	173,124	95,310	189,00
West Texas			
Pakenham	3,554	53,937	12,54
Other	373	6,652	1,48
Total West Texas	3,927	60,589	14,02

Total U.S. Properties	177,051	155,899	203,03
Foreign Properties			
Yombo, Congo	13,872	--	13,87
Other	228	841	36
Total Foreign Properties	14,100	841	14,24
Total Continuing Operations	191,151	156,740	217,27
Brea Olinda (1)	29,186	17,945	32,17
Total Properties	220,337	174,685	249,45

(1) Brea-Olinda is reflected as an asset held for sale at December 31, 2002 and the results of operations from this field are reflected as discontinued operations in our financial statements. The sale was completed in February 2003.

OIL AND GAS OPERATIONS

Domestic Operations

The following discussion pertains to our domestic oil and gas assets that are held for continuing use and, accordingly, does not include the Brea-Olinda field which was sold in February 2003.

Our domestic operations are concentrated in three areas: California onshore, California offshore and West Texas. At December 31, 2002, our U.S. proved reserves totaled approximately 203.0 MMBOE or 93% of our total proved reserve base. During 2002, domestic production averaged 43.4 MBOE/day, or 89% of total production.

We continue to increase the value of our domestic oil and gas assets through development drilling, workovers, recompletions, secondary and tertiary recovery operations and other production enhancement techniques to maximize current production and the ultimate recovery of reserves. Capital additions to our domestic oil and gas properties excluding acquisitions was $53 million in 2002 and are currently budgeted at approximately $60 to 65 million in 2003. The main focus of our 2003 exploitation program will be directed

toward the continued successful development of our thermal properties in the Cymric, Belridge and Midway-Sunset fields in California and our newly acquired Pakenham field in West Texas.

California Onshore. Net proved reserves were 137.1 MMBOE at December 31, 2002, and production averaged 27.8 MBOE/day in 2002. Our main California onshore properties include interests in the Cymric, Midway-Sunset and Belridge fields in the San Joaquin Basin in Kern County, California. We have onshore properties that utilize thermal operations to maximize current production and the ultimate recovery of reserves. We own a 100% working interest (93% net revenue) in our properties in the Cymric field and the entire working interest and an average net revenue interest of approximately 97% in our properties in the Midway-Sunset field. Production is from several zones in the Cymric field, including the Tulare, Diatomite and Point of Rocks formations and the Antelope Shale. The Midway-Sunset field produces from five zones with the Potter Sand and the thermal Diatomite accounting for the majority of the total production. We operate the deeper zones of the Belridge field in fee with 100% working and net revenue interests. Production from the Belridge field is from the Tulare formation.

California Offshore. Net proved reserves were 51.9 MMBOE at December 31, 2002, and production averaged 14.7 MBOE/day in 2002. Offshore California, we operate 12 platforms; 10 in federal waters and 2 in state waters. The Point Pedernales, Dos Cuadras and East Dos Cuadras, and Santa Clara fields are our largest fields. We own an 80% working interest (67% net revenue) in the Point Pedernales field which is located 3.5 miles offshore Santa Barbara County, California, in federal waters. Production is from the Monterey Shale at depths from 3,500-5,150 feet. The Dos Cuadras and East Dos Cuadras fields are located offshore five and one-half miles from Santa Barbara in the Santa Barbara Channel. We operate three platforms with a 50% working interest (42% net revenue) and a fourth platform with a 67.5% working interest (56% net revenue). We have a 100% working interest (83% net revenue) in the Santa Clara field.

West Texas. We have properties located in West Texas that were acquired in September 2002 with a total proved reserve base of 14.0 MMBOE at December 31, 2002, and production in the fourth quarter of 2002 was 18.6 MMcfe/day. The main asset is the Pakenham field in Terrell County, Texas. We are the operator of the Pakenham field and own approximately a 98% working interest (73% net revenue) in this field.

International Operations

At December 31, 2002, our estimated international net proved reserves totaled 14.2 MMBOE, or 7% of our total proved reserve base. During 2002, our international production averaged 5.2 MBOE/day, or 11% of our total production. See "Risk Factors and Cautionary Statement for Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995" for a discussion of the risks of our international investments.

Congo. Our international reserves and production consist primarily of a non-operating 50% working interest (37.0% average net revenue) in the Yombo oil field located in the Marine 1 Permit offshore the Republic of Congo in West Africa ("Congo"). Estimated net proved reserves of the Yombo oil field as of December 31, 2002 were 13.9 MMBbl, and production during 2002 averaged 5.2 MBOE/day. In 2002 revenues relating to production from the Yombo field accounted for approximately 11% of our total oil and gas revenues. The properties are located 27 miles offshore in approximately 370 feet of water. We also own a 50% interest in a converted super tanker with storage capacity of over one million barrels of oil for use as a floating production, storage and off loading vessel ("FPSO"). Our production is converted on the FPSO to No. 6 fuel oil with less than 0.3% sulfur content. We also have a 50% interest in the Masseko field which is currently under renewed analysis for possible development by Perenco, the new operator. Should circumstances change in the future, we may pursue development of the field.

During 2000 and 2001, a five well development program was implemented. This highly successful program increased our net production in the Congo from 5,000 BOPD in October 2000 to a peak production rate of 6,450 BOPD in August 2001. The individual wells produced at rates between 500 and 1,800 BOPD. The field is currently fully developed, due to the lack of slots for new wells. As additional slots become available, additional drilling activity is possible.

Tunisia. We have a 42.86% participating interest in the 768,900 acre Fejaj Permit located onshore central Tunisia. Beginning in December 2002, the partnership re-entered the Chott Fejaj #3-A well and deepened the well from 3,532 meters to a total depth of 4,637 meters to evaluate the pre-Jurassic section of the Chott Fejaj structure. This well has subsequently been plugged and abandoned as a dry hole. Our net cost for the well is estimated to be approximately $1.1 million, of which $0.4 million was expensed in the fourth quarter 2002. We have no further plans for involvement in Tunisia.

In January 2002, we withdrew our request for formal government approval of the Convention and Joint Venture Agreement resulting in the relinquishment of our 100% interest in the Alyane Permit located offshore Tunisia in the Gulf of Gabes. In June 2002, we conveyed our 22.5% participating interest and future obligations in the Anaguid Permit, located onshore southern Tunisia in the Ghadames Basin, to our partners Anadarko Tunisia Anaguid Company and Pioneer Natural Resources Anaguid Ltd.

Canada. We acquired a 50% working interest in 22,140 acres in the Marten Hills heavy oil play in Alberta, Canada for approximately $0.4 million in 2000. The cyclic steaming potential of the acreage was evaluated in 2001, and was determined to be non-commercial and we relinquished the acreage in 2002.

Ghana. In 2001, we relinquished our 1.9 million acre Accra-Keta Permit offshore the Republic of Ghana and recorded an impairment of $1.0 million. The Permit was relinquished prior to the commencement of the second phase of the work program. We were the operator of this Permit and held a 50% working interest.

DRILLING ACTIVITIES

The following discussion pertains to our oil and gas assets that are held for continuing use and, accordingly, does not include the Brea-Olinda field which was sold in February 2003.

Acreage

The following table sets forth the acres of developed and undeveloped oil and gas properties in which we held an interest as of December 31, 2002. Undeveloped acreage are leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether or not such acreage contains proved reserves. A gross acre refers to the number of acres in which we directly own a working interest. The number of net acres is the sum of the fractional ownership of working interests we directly own in the gross acres expressed as a whole number and percentages. A "net acre" is deemed to exist when the sum of our fractional ownership of working interests in gross acres equals one.

	Gross	Net
Developed Acreage	216,357	143,267
Undeveloped Acreage	1,055,132	469,073
Total	1,271,489	612,340

The following table sets forth our undeveloped acreage at December 31, 2002:

	Gross	Net
California(1)	235,177	114,685
Congo, West Africa:		
Marine 1 Permit	38,000	19,000
Tunisia, North Africa	768,900	326,528
Other	13,055	8,860
Total	1,055,132	469,073

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(1) Includes COOGER acreage which is offshore

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Productive Wells

The following table sets forth our gross and net interests in productive oil and gas wells at December 31, 2002. Productive wells are producing wells and wells capable of production.

	Gross	Net
Oil Wells	2,449	1,865
Gas Wells	378	293
Total	2,827	2,158

Drilling Activity

Our drilling activities in 2002 were in the continental United States and offshore California in state and federal waters, and offshore Congo.

At December 31, 2002, we had 1 gross (0.43 net) exploration well in progress. The following table details the results of our drilling activity, net to our interest, for the last three calendar years. Gross wells are the number of wells in which we own a direct working interest. The number of net wells is the sum of the fractional ownership of working interests we directly own in gross wells.

Exploratory Wells

	Gross			Net		
	Productive	Dry Holes	Total	Productive	Dry Holes	To
2000	11	2	13	11	1.45	
2001	1	8	9	1	4.95	
2002	--	1	1	--	0.43	

	Development Wells					
	Gross			Net		
	Productive	Dry Holes	Total	Productive	Dry Holes	To
2000	175	3	178	173.25	2.68	
2001	101	1	102	95.98	1.00	
2002	104	3	107	104.00	3.00	

In 2002, we drilled 42 development wells in the Cymric field in central California, which contained 31% of our total estimated net proved equivalent reserves at December 31, 2002, and anticipate drilling approximately 27 development wells in the Cymric field during 2003. In the Midway-Sunset field in central California, which contained 9% of the total estimated net proved equivalent reserves at December 31, 2002, we drilled 40 development wells during 2000, and deferred the development in this field to 2002 where we drilled 32 development wells and plan to drill 20 development wells in 2003. In the Belridge field which contained 6% of the total estimated net proved equivalent reserves at December 31, 2002, we drilled 27 development wells during 2002, and plan to drill approximately 30 development wells in 2003.

We initiated a waterflood project in the Yombo field offshore Congo to enhance production from existing Upper Sendji and Tchala zones in 1999. The development program continued during 2000 and 2001, drilling a total of 5 infill wells which increased our production approximately 30% from 2000 to 2001. Both pipelines originating from our platforms to the Conkouati (FPSO) were replaced in 2001. Plans for 2003 include two conversions of producing wells to water injection, two recompletions and facility maintenance.

ACQUISITIONS AND DIVESTITURES OF OIL AND GAS PRODUCING PROPERTIES

We have, from time to time, been an active participant in the market for oil and gas properties. We also seek to divest lower growth assets at times when those assets are valued highly by the marketplace.

In September 2002, we acquired Athanor Resources, Inc. for $101.4 million. Proved reserves from this acquisition were approximately 6% of our total estimated net proved equivalent reserves at December 31, 2002. The reserves are located in Terrell County in West Texas. We drilled 4 development wells in the fourth quarter of 2002 and plan to drill 8 to 10 development wells in 2003. We have increased production from the property by 15% since closing the acquisition in September 2002.

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.

In January 2001, we acquired producing properties located southeast of our interest in the Cymric field in Kern County, California for approximately $28.5 million.

In 2000, we sold our working interest in the Las Cienegas field in California for approximately $4.6 million.

REAL ESTATE

In 1996, along with our acquisition of certain California oil and gas properties, we acquired tracts of land in Orange and Santa Barbara Counties in California, and nearly 8,000 acres of agricultural property in the central valley of California. As of December 31, 2002, the carrying amount of this land totaled $40.8 million of which $35.8 million is classified as assets held for sale.

In 2003, we expect to monetize a significant portion of our California real estate portfolio. Our entitlement application for the Tonner Hills residential development covering approximately 810 acres in northern Orange County received unanimous approval from the Orange County Board of Supervisors on November 19, 2002. On December 18, 2002, Hills for Everyone, a non-profit organization, filed suit against Orange County ("Respondent") and Nuevo Energy Company ("Real Party in Interest") in an effort to set aside the Orange County approval. We will be actively addressing this lawsuit during 2003 as we continue our project development activities.

MARKETS

The markets for hydrocarbons continue to be quite volatile. Our financial condition, operating results, future growth and the carrying value of our oil and gas properties are substantially dependent on oil and gas prices. The ability to maintain or increase our borrowing capacity and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond our control. These factors include weather conditions in the United States, the condition of the United States economy, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, the price of foreign oil imports and the availability of alternate fuel sources. Any substantial and extended decline in the price of oil and gas could have an adverse effect on the carrying value of our proved reserves, borrowing capacity, our ability to obtain additional capital, and our revenues, profitability and cash flows from operations.

The price of natural gas and the threat of electrical disruptions are factors that can create volatility in our California oil operations. We have historically had a long position in natural gas in California where we produce more natural gas than we consume in thermal crude production. As gas prices escalated in late 2000, we began to sell our California gas production to the market rather than consume it in less economic steaming operations. In 2002, we entered into certain natural gas purchase and crude oil sales hedges to protect the economic margin on a portion of our thermal oil production beginning in 2003.

In California, we generate a total of 13 Megawatts ("MW") of power at various sites and consume approximately 65% in our operations. Three turbines in Kern County produce 12 MW of power and cogenerate 15% of our total steam needs in thermal operation. By self-generating power consumption in Kern County, we have reduced our exposure to rising electricity prices. With the exception of the Point Pedernales field, for which we have contracted for firm electric power service, most of our facilities receive power under interruptible service contracts. Considering the fact that California has experienced shortages of electricity and some of our facilities receive interruptible service, we could experience periodic power interruptions. In addition, the State of California could increase power costs, change existing rules or impose new rules or regulations with respect to power that could impact our operating costs.

Production of California San Joaquin Valley heavy oil (defined herein as those fields which produce primarily 15 degrees API quality crude oil or heavier through thermal operations) constituted 53% of our total 2002 crude output. In addition, properties which produce primarily other grades of relatively heavy oil (generally, 20 degrees API or heavier, but produced through non-thermal operations) constituted 12% of our total 2002 crude output. The market price for California heavy oil differs from the established market indices for oil elsewhere in the U.S., due principally to the higher transportation and refining costs associated with heavy oil. We entered into a 15-year contract, effective January 1, 2000, to sell all of our current and future California crude oil production to Tosco Corporation (now ConocoPhillips). The contract provides pricing based on a fixed percentage of the NYMEX crude oil price for each type of crude oil that we produce in California. Effective January 1, 2003, we renegotiated this contract relative to our Point Pedernales production, effectively increasing our price on 10% of our 2003 crude output by 14.5% on the NYMEX price. While the contract does not reduce our exposure to price volatility, it does effectively eliminate the risk of widening basis differential between the NYMEX price and the field price of our California oil production. In doing so, the contract makes it substantially easier for us to hedge our realized prices. The ConocoPhillips contract permits us, under certain circumstances, to separately market up to ten percent of our California crude oil production. We exercised this right in 2001 and 2002 and sold 5,000 BOPD of our San Joaquin Valley oil production to a third party under a one-year contract containing NYMEX pricing. A new contract was entered into for a two-year period on January 1, 2003.

Our Yombo field production in Marine 1 Permit offshore Congo produces a relatively heavy crude oil (16-20 degrees API gravity) which is processed into a low-sulfur, No. 6 fuel oil product for sale to worldwide markets. Production from this property constituted 11% of our total 2002 oil production. The market for residual fuel oil differs from the markets for WTI and other benchmark crudes due to its primary use as an industrial or utility fuel versus the higher value transportation fuel component, which is produced from refining most grades of crude oil.

Sales to ConocoPhillips Corporation accounted for 73%, 63% and 84% of 2002, 2001 and 2000 oil and gas revenues. Sales to Torch Energy Marketing ("TEMI") accounted for 23% and 11% of 2001 and 2000 oil and gas revenues. In January 2003, we brought in house the marketing of our oil production and we no longer have sales to TEMI. Coral Energy began marketing our natural gas in

January 2002. The loss of any single significant customer or contract could have a material adverse short-term effect. However, our management does not believe that the loss of any single significant customer or contract would materially affect our business in the long-term.

REGULATION

Oil and Gas Regulation

The availability of a ready market for oil and gas production depends upon numerous factors beyond our control. These factors include state and federal regulation of oil and gas production and transportation, as well as regulations governing environmental quality and pollution control, state limits on allowable rates of production by a well or proration unit, the amount of oil and gas available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. For example, a productive gas well may be "shut-in" because of an over-supply of gas or lack of an available gas pipeline in the areas in which we may conduct operations. State and federal regulations are generally intended to prevent waste of oil and gas, protect rights to produce oil and gas between owners in a common reservoir, and control contamination of the environment. Pipelines and gas plants are also subject to the jurisdiction of various Federal, state and local agencies which may affect the rates at which they are able to process or transport gas from our properties.

Our sales of natural gas are affected by the availability, terms and costs of transportation. The rates, terms and conditions applicable to the interstate transportation of gas by pipelines are regulated by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Acts ("NGA"), as well as under Section 311 of the Natural Gas Policy Act ("NGPA"). Since 1985, the FERC has implemented regulations intended to increase competition within the gas industry by making gas transportation more accessible to gas buyers and sellers on an open-access, non-discriminatory basis.

Our sales of oil are also affected by the availability, terms and costs of transportation. The rates, terms, and conditions applicable to the interstate transportation of oil by pipelines are regulated by the FERC under the Interstate Commerce Act. FERC has implemented a simplified and generally applicable ratemaking methodology for interstate oil pipelines to fulfill the requirements of Title VIII of the Energy Policy Act of 1992 comprised of an indexing system to establish ceilings on interstate oil pipeline rates. The FERC has announced several important transportation-related policy statements and rule changes, including a statement of policy and final rule issued February 25, 2000 concerning alternatives to its traditional cost-of-service rate-making methodology to establish the rates interstate pipelines may charge for their services. The final rule revises FERC's pricing policy and current regulatory framework to improve the efficiency of the market and further enhance competition in natural gas markets.

With respect to transportation of natural gas on the Outer Continental Shelf ("OCS'), the FERC requires, as a part of its regulation under the Outer Continental Shelf Lands Act ("OCSLA"), that all pipelines provide open and non-discriminatory access to both owner and non-owner shippers. Although to date the FERC has imposed light-handed regulation on offshore facilities that meet its traditional test of gathering status, it has the authority to exercise jurisdiction under the OCSLA over gathering facilities, if necessary, to permit non-discriminatory access to service. For those facilities transporting natural gas across the OCS that are not considered to be gathering facilities, the rates, terms and conditions applicable to this transportation are regulated by FERC under the NGA and NGPA, as well as the OCSLA. With respect to the transportation of oil and condensate on or across the OCS, the FERC requires, as part of its regulation under the OCSLA, that all pipelines provide open and non-discriminatory access to both owner and non-owner shippers. Accordingly, the FERC has the authority to exercise jurisdiction under the OCSLA, if necessary, to permit non-discriminatory access to service.

In the event we conduct operations on federal, state or Indian oil and gas leases, such operations must comply with numerous regulatory restrictions, including various nondiscrimination statutes, royalty and related valuation requirements, and certain of such operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Bureau of Land Management ("BLM") or Minerals Management Service ("MMS") or other appropriate federal or state agencies.

Our OCS leases in federal waters are administered by the MMS and require compliance with detailed MMS regulations and orders. The MMS has promulgated regulations implementing restrictions on various production-related activities, including restricting the flaring or venting of natural gas. Under certain circumstances, the MMS may require any of our operations on federal leases to be suspended or terminated. Any

such suspension or termination could materially and adversely affect our financial condition and operations. On March 15, 2000, the MMS issued a final rule effective June 1, 2000, that amends its regulations governing the calculation of royalties and the valuation of crude oil produced from federal leases. Among other matters, this rule amends the valuation procedure for the sale of federal royalty oil by eliminating posted prices as a measure of value and relying instead on arm's length sales prices and spot market prices as market value indicators. Because we generally sell our production to third parties and pay royalties based on proceeds actually received from the sale of production from federal leases, it is not anticipated that this final rule will have a substantial impact on us.

The Mineral Leasing Act of 1920 ("Mineral Act") prohibits direct or indirect ownership of any interest in federal onshore oil and gas leases by a foreign citizen of a country that denies "similar or like privileges" to citizens of the United States. Such restrictions on citizens of a "non-reciprocal" country include ownership or holding or controlling stock in a corporation that holds a federal onshore oil and gas lease. If this restriction is violated, the corporation's lease can be canceled in a proceeding instituted by the United States Attorney General. Although the regulations of the BLM (which administers the Mineral Act) provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. We own interests in numerous federal onshore oil and gas leases. It is possible that holders of equity interests in us may be citizens of foreign countries, which at some time in the future might be determined to be non-reciprocal under the Mineral Act.

Our pipelines used to gather and transport our oil and gas are subject to regulation by the Department of Transportation ("DOT") under the Hazardous

Liquids Pipeline Safety Act of 1979, as amended ("HLPSA") relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. The HLPSA requires us and other pipeline operators to comply with regulations issued pursuant to HLPSA designed to permit access to and allowing copying of records and to make certain reports and provide information as required by the Secretary of Transportation.

The Pipeline Safety Act of 1992 (The "Pipeline Safety Act") amends the HLPSA in several important respects. It requires the Research and Special Programs Administration ("RSPA") of DOT to consider environmental impacts, as well as its traditional public safety mandate, when developing pipeline safety regulations. In addition, the Pipeline Safety Act mandates the establishment by DOT of pipeline operator qualification rules requiring minimum training requirements for operators, and requires that pipeline operators provide maps and records to RSPA. It also authorizes RSPA to require certain pipeline modifications as well as operational and maintenance changes. We believe our pipelines are in substantial compliance with HLPSA and the Pipeline Safety Act. Nonetheless, significant expenses would be incurred if new or additional safety measures are required.

Environmental Regulation

General. Our activities are subject to existing federal, state and local laws and regulations governing environmental quality and pollution control in the United States and may be subject to laws and regulations of the Republic of Congo, West Africa. It is anticipated that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulations governing the release of materials in the environment or otherwise relating to the protection of the environment will not have a material effect upon our operations, capital expenditures, earnings or competitive position.

Our activities with respect to exploration, drilling and production from wells, natural gas facilities, including the operation and construction of pipelines, plants and other facilities for transporting, processing, treating or storing natural gas and other products, are subject to stringent environmental regulation by state and federal authorities including the Environmental Protection Agency ("EPA"). Such regulation can increase the cost of planning, designing, installing and operating such facilities. In most instances, the regulatory requirements relate to water and air pollution control measures. (See Note 12 to the Notes to the Consolidated Financial Statements).

With respect to our oil and gas operations in California, we have significant exit cost liabilities. These liabilities include costs for dismantlement, rehabilitation and abandonment. As of December 31, 2002, our total estimated costs for future dismantlement, abandonment and site restoration was $177.6 million. We are not indemnified for any part of these exit costs. (See Note 2 to the Notes to the Consolidated Financial Statements).

Waste Disposal. We currently own or lease, and have in the past owned or leased, numerous properties that have been used for production of oil and gas for many years. Although we utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties that we currently own or lease or properties that we have in the past owned or leased. In addition, many of these properties have been operated by third parties over whom we had no control as to such entities' treatment of hydrocarbons or other wastes or the manner in which such substances may have been disposed of or released. State and federal laws applicable to oil and gas wastes and properties have become stricter. Under new laws, we could be required to remediate property, including ground water, containing or impacted by previously disposed wastes (including wastes disposed of or released by prior owners or operators) or to perform remedial plugging operations to prevent future or mitigate existing contamination.

We may generate wastes, including hazardous wastes that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The EPA has limited the disposal options for certain wastes that are designated as hazardous under RCRA ("Hazardous Wastes"). Furthermore, it is possible that certain wastes generated by our oil and gas operations that are currently exempt from treatment as Hazardous Wastes may in the future be designated as Hazardous Wastes, and therefore be subject to more rigorous and costly operating and disposal requirements.

Superfund. The federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes joint and several liability for costs of investigation and remediation and for natural resource damages, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances ("Hazardous Substances"). These classes of persons or potentially responsible parties ("PRP's") include the current and certain past owners and operators of a facility where there is or has been a release or threat of release of a Hazardous Substance and persons who disposed of or arranged for the disposal of the Hazardous Substances found at such a facility. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the PRP's the costs of such action. Although CERCLA generally exempts petroleum from the definition of Hazardous Substances in the course of our operations, we may have generated and may generate wastes that fall within CERCLA's definition of Hazardous Substances. We may also be an owner of facilities on which Hazardous Substances have been released by previous owners or operators. We may be responsible under CERCLA for all or part of the costs to clean up facilities at which such substances have been released and for natural resource damages. Crude oil exempt under Superfund may be modified increasing compliance costs. We have not been named a PRP under CERCLA nor do we know of any prior owners or operators of our properties that are named as PRP's related to their ownership or operation of such property.

Air Emissions. Our operations are subject to local, state and federal regulations for the control of emissions of air pollution. Local air quality districts do much of the air quality regulation of sources in California. California requires new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed permitting requirements, including additional permits. Because of the severity of the ozone (smog) problems in portions of California, the state has the most severe restrictions on the emissions of volatile organic compounds (VOC) and nitrogen oxides (Nox) of any state. Producing wells, gas plants and electric generating facilities, all of which are owned by us generate VOC and Nox. Some of our producing wells are in counties that are designated as nonattainment for ozone and are therefore potentially subject to restrictive emission limitations and permitting requirements. If the ozone problems in the state are not resolved by the deadlines imposed by the federal Clean Air Act (2005 - 2010), even more restrictive requirements may be imposed including financial penalties based upon the quantity of ozone producing emissions. California also operates a stringent program to control hazardous (toxic) air pollutants, which might require installation of additional controls. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could require us to forego construction, modification or operation of certain air emission sources, although we believe that in the latter cases we would have enough permitted or permittable capacity to continue our operations without a material adverse effect on any particular producing field.

Clean Water Act. The Clean Water Act ("CWA") imposes restrictions and strict controls regarding the discharge of wastes, including produced waters and other oil and natural gas wastes, into waters of the United States, a term broadly defined. These controls have become more stringent over the years, and it is probable that additional restrictions will be imposed in the future. Permits must be obtained to discharge pollutants into federal waters. The CWA provides for civil, criminal and administrative penalties for unauthorized discharges of oil, hazardous substances and other pollutants. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or hazardous substances. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or it derivatives, or other hazardous substances, into state waters. In addition, the EPA has promulgated regulations that may require us to obtain permits to discharge storm water runoff, including discharges associated with construction activities. In the event of an unauthorized discharge of wastes, we may be liable for penalties and costs.

Oil Pollution Act. The Oil Pollution Act of 1990 ("OPA"), which amends and augments oil spill provisions of CWA, imposes certain duties and liabilities on "responsible parties" related to the prevention of oil spills and damages resulting from such spills in United States waters and adjoining shorelines. A "responsible party" includes the owner or operator of a facility or vessel, that is a source of an oil discharge or poses the substantial threat of discharge, or the lessee or permittee of the area in which a facility covered by OPA is located. OPA assigns joint and several liability, without regard to fault, to each responsible party for oil removal costs and a variety of public and private damages. Few defenses exist to the liability imposed by OPA. In the event of an oil discharge, or substantial threat of discharge from our properties, vessels and pipelines, we may be liable for costs and damages.

The OPA also imposes ongoing requirements on a responsible party, including proof of financial responsibility to cover at least some costs in a potential spill. Certain amendments to the OPA that were enacted in 1996 require owners and operators of offshore facilities that have a worst case oil spill potential of more than 1,000 barrels to demonstrate financial responsibility in amounts ranging from $10 million in specified state waters and $35 million in federal outer continental shelf waters, with higher amounts, up to $150 million based upon worst case oil-spill discharge volume calculations. We believe that we currently have established adequate proof of financial responsibility for our offshore facilities.

California Coastal Act. The California Coastal Act regulates the conservation and development of California's coastal resources. The California Coastal Commission ("The Commission") works with local government to make permit decisions for new development in certain coastal areas and reviews local coastal programs, such as land use restrictions. The Commission also works with the California State Office of Oil Spill Prevention and Response to protect against and respond to coastal oil spills. The Commission has direct regulatory authority over offshore oil and gas development within the State's three mile jurisdiction and has authority, through the Federal Coastal Zone Management Act, over federally permitted projects that affect the State's coastal zone resources. We conduct activities that may be subject to the California Coastal Act and the jurisdiction of The Commission.

Our management believes that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance will not have a material adverse impact on us.

COMPETITION

We operate in the highly competitive areas of oil and gas exploration, development and production. The availability of funds and information relating to a property, the standards established by us for the minimum projected return on investment and the availability of alternate fuel sources are factors that affect our ability to compete in the marketplace. Competitors include major integrated oil companies and a substantial number of independent energy companies, many of which possess greater financial and other resources. We compete to acquire producing properties, exploration leases, licenses, concessions and marketing agreements.

PERSONNEL

At December 31, 2002, we had 412 full time employees. In 2002, we brought California field operations, oil marketing, human resources, accounting, treasury and land administration in house.

ITEM 2. PROPERTIES

A description of our properties is included in Item 1, Business, and is incorporated herein by reference.

ITEM 3. LEGAL PROCEEDINGS

See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, which is incorporated herein by reference.

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

None.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Our common stock is traded is the New York Stock Exchange under the Symbol NEV. On March 24, 2003, we had 19,209,290 shares of common stock outstanding. There were approximately 955 stockholders of record and approximately 2,566 additional beneficial owners as of March 24, 2003. We have not paid dividends on our common stock and do not anticipate paying cash dividends in the immediate future. In addition, certain restrictions contained in our financing arrangements restrict the payment of dividends. See Note 9 to the Notes to Consolidated Financial Statements. The high and low recorded prices of our common stock during 2002 and 2001 are presented in the following table.

	Market Price	
	High	Low
2002		
First Quarter	$ 15.580	$ 13.150
Second Quarter	$ 16.450	$ 13.600
Third Quarter	$ 15.900	$ 9.000
Fourth Quarter	$ 14.550	$ 10.560
2001		
First Quarter	$ 19.350	$ 15.875
Second Quarter	$ 21.560	$ 15.250
Third Quarter	$ 18.500	$ 13.000
Fourth Quarter	$ 16.000	$ 11.100

Treasury Stock Repurchases

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 2002. As of December 31, 2002, we had 3.9 million shares of treasury stock.

Shareholder Rights Plan

In 1997, we adopted a Shareholder Rights Plan to protect our shareholders from coercive or unfair takeover tactics. Under the Shareholder Rights Plan, each outstanding share and each share of subsequently issued common stock has attached to it one Right. Generally, in the event a person or group ("Acquiring Person") acquires or announces an intention to acquire beneficial ownership of 15% or more of the outstanding shares of common stock without our prior consent, or we are acquired in a merger or other business combination, or 50% or more of our assets or earning power is sold, each holder of a Right will have the right to receive, upon exercise of the Right, that number of shares of common stock of the acquiring company, which at the time of such transaction will have a market price of two times the exercise price of the Right. We may redeem the Right for $0.01 at any time before a person or group becomes an Acquiring Person without prior approval. The Rights will expire on March 21, 2007, subject to earlier redemption by us.

In 2000, we amended the Shareholder Rights Plan to provide that if we receive and consummate a transaction pursuant to a qualifying offer, the provisions of the Shareholder Rights Plan are not triggered. In general, a qualifying offer is an all cash, fully funded tender offer for all of our outstanding common stock by a person who, at the commencement of the offer, beneficially owns less than 5% of the outstanding common stock. A qualifying offer must remain open for at least 120 days, must be conditioned on the person commencing the qualifying offer acquiring at least 75% of the outstanding common stock and the per share consideration must exceed the greater of: (1) 135% of the highest closing price of our common stock during the one-year period prior

to the commencement of the qualifying offer or (2) 150% of the average closing price of our common stock during the 20 day period prior to the commencement of the qualifying offer.

Executive Compensation Plan

In 1997, we adopted a plan to encourage senior executives to personally invest in our stock, and to regularly review executives' ownership versus targeted ownership objectives. These incentives include a deferred compensation plan (the "Plan") that gives key executives the ability to defer all or a portion of their salaries and bonuses and invest in our common stock or make other investments at the employee's discretion. Stock acquired at a discount prior to the 2001 amendment of the Plan is restricted for a two-year period. All stock acquired is held in a benefit trust. Target levels of ownership are based on multiples of base salary and are administered by the Compensation Committee of the Board of Directors. The Plan applies to certain highly compensated employees and all executives at a level of Vice-President and above. The Plan was amended in 2001 to remove the discount on investments in our common stock and to provide additional investment alternatives. The Plan was further amended in July 2002 to remove the right to receive withdrawals in cash.

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data should be read in conjunction with the consolidated financial statements and supplementary information included in Item 8, Financial Statements and Supplementary Data.

	As of and for the Years ended De			
	2002	2001	2000	
	(in thousands, except per share			
Operating Results Data				
Revenues				
Oil and gas revenues	$ 318,986	$ 327,034	$ 286,505	$
Other	4,070	273	2,358	

Total revenues	323,056	327,307	288,863
Costs and expenses			
Lease operating expense	138,017	167,211	140,175
Exploration	4,541	22,058	9,774
Depreciation, depletion and amortization	75,311	71,629	59,242
Impairments	--	103,490	--
General and administrative	25,877	36,904	32,974
Interest expense	37,943	43,006	37,472
Dividends on TECONS	6,613	6,613	6,613
Income (loss) from continuing operations	25,464	(86,564)	61
Income (loss) from discontinued operations, including gain/loss on disposal, net of income taxes	(13,189)	7,393	12,370
Cumulative effect of a change in accounting principle	--	--	(796)
Net income (loss)(1)	12,275	(79,171)	11,635
Earnings Per Share			
Basic	0.70	(4.73)	0.67
Diluted	0.69	(4.73)	0.64
Financial Position Data			
Total assets	$ 855,171	$ 839,812	$ 848,024
Senior Subordinated Notes	409,577	409,577	409,727
Bank Credit Facility	28,700	41,500	--
Total debt	438,277	451,077	409,727
Interest rate swaps - fair value adjustment	2,161	(633)	--
Interest rate swaps - termination gain	11,673	--	--
Long-term debt	452,111	450,444	409,727
Company-Obligated Mandatorily Redeemable Convertible Preferred Securities of Nuevo Financing I (TECONS)	115,000	115,000	115,000

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(1) No common stock dividends have been declared since our formation. See Note 9 to the Notes to Consolidated Financial Statements concerning restrictions on the payment of common stock dividends

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Nuevo Energy is engaged in the acquisition, exploitation, development, exploration and production of crude oil and natural gas. Our core areas in the U.S. are onshore and offshore California and West Texas. We also have international crude oil production in the Republic of Congo. The following review should be read in conjunction with our Consolidated Financial Statements and Notes thereto.

In September 2002, we acquired Athanor Resources, Inc. (Athanor). Effective September 18, 2002, the results of Athanor's operations are included in the consolidated financial statements. The purchase price totaling approximately $101.4 million was comprised of a combination of $61.3 million of available cash and additional borrowings, the issuance of approximately $20.1 million of our common stock 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 the allocation of approximately $19.7 million to goodwill.

RESULTS OF OPERATIONS

Our results of operations are significantly affected by fluctuations in oil and gas prices. The following table reflects our production and average prices for oil and natural gas:

	Year Ended December 31,		
	2002	2001	2000
Crude Oil and Liquids			
Sales Volumes (MBbls/d)			
Domestic	37.8	37.3	39.9
International	5.1	5.2	5.0
Total	42.9	42.5	44.9
Sales Prices ($/Bbl)			
Unhedged	$ 18.81	$ 18.98	$ 21.40
Hedged	18.21	15.92	14.23
Revenues ($/thousands)			
Domestic	$ 263,464	$ 259,666	$ 314,848
International	32,104	36,015	37,328
Marketing Fees	(936)	(957)	(1,079)
Hedging	(9,414)	(47,558)	(117,673)
Total	$ 285,218	$ 247,166	$ 233,424
Natural Gas			
Sales Volumes (MMcf/d)			
Domestic	34.4	30.5	33.8
Sales Prices ($/Mcf)			
Unhedged	$ 2.69	$ 7.18	$ 4.31
Hedged	2.69	N/A	N/A
Revenues ($/thousands)			
Domestic	$ 34,607	$ 80,806	$ 53,789
Hedging	(49)	--	--
Marketing Fees	(790)	(938)	(708)
Total	$ 33,768	$ 79,868	$ 53,081

Lease operating costs per BOE			
Domestic	$ 8.02	$ 9.89	$ 7.62
International	5.71	7.44	7.39
Total	7.77	9.62	7.59

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YEAR ENDED DECEMBER 31, 2002 COMPARED TO YEAR ENDED DECEMBER 31, 2001

We had net income of $12.3 million, or $0.69 per diluted share for 2002 as compared to a net loss of $79.2 million, or ($4.73) per diluted share in 2001.

Revenues

Oil and Gas Revenues. Oil and gas revenues were $319.0 million in 2002 compared to $327.0 million in 2001 principally due to lower natural gas prices which were partially offset by higher crude oil prices realized, lower hedging losses and higher crude oil and natural gas production. The realized oil price in 2002 was $18.21 per Bbl, an increase of $2.29 per Bbl from 2001. Crude oil production averaged 42.9 MBbls/day in 2002, an increase of 0.4 MBbls/day from 2001. The increased production was due to higher production at Point Pedernales and Santa Clara due to improved performance which was partially offset by lower production at Cymric where production was curtailed for well repairs. We had a hedging loss of $9.4 million in 2002 compared to a hedging loss of $47.6 million in 2001. Natural gas production averaged 34.4 MMcf per day in 2002, an increase of 13% from 30.5 MMcf per day in 2001 primarily due to production from the Pakenham field acquired in September 2002. The realized natural gas price in 2002 was $2.69 per Mcf, which decreased 63% from $7.18 per Mcf in 2001.

Other Revenue. Other revenue of $4.1 million in 2002 was $3.8 million higher than 2001 principally due to $3.0 million of business interruption insurance recoveries received in 2002, related to the repair of our pipelines at the Point Pedernales field.

Costs and Expenses

Costs and Expenses. Lease operating expenses ("LOE") of $138.0 million in 2002 decreased 17% from 2001. We use gas as a feedstock to generate steam which is injected into reservoirs to facilitate the production of heavy California oil. Excluding the cost of steam used in our oil production operations, LOE decreased 12% in 2002 compared to 2001. Exploration costs of $4.5 million in 2002 were $17.6 million lower than $22.1 million in 2001. The 2002 exploration costs included a $2.3 million non-cash write off the Anaguid permit in Tunisia which was conveyed to third parties while the 2001 costs included $14.1 million of dry hole costs. Depreciation, depletion and amortization ("DD&A") was $75.3 million in 2002 compared to $71.6 million in the prior year primarily due to higher production and a higher DD&A rate. The DD&A rate was $4.24 per BOE in 2002 compared to $4.12 per BOE in 2001. Due to lower outsourcing costs, legal fees and project costs, general and administrative expense of $25.9 million in 2002 was $11.0 million lower than 2001. We had no impairments in 2002 compared to $103.5 million in 2001. The impairment in 2001 was on our Santa Clara, Huntington Beach, Pitas Point, Masseko (Congo) and Point

Pedernales fields and certain other oil and gas properties. In 2002, there were no restructuring and severance charges as compared to $4.9 million in 2001. The 2001 restructuring charges were related to the termination of two outsourcing contracts and the reorganization of our exploration and production operations. Other expenses were $1.9 million in 2002 compared to $14.9 million in 2001 which included the termination of hedging contracts with Enron and various consulting and legal costs.

Loss on Assets Held for Sale. In 2002, we made the decision to sell certain real estate in California. Accordingly, we transferred the underlying net book value of this real estate to assets held for sale and recorded a $1.3 million loss, representing the write down to its estimated fair market value, less costs to sell. In 2001, we made the decision not to proceed with our power plant project in Santa Barbara and Kern County California and transferred our remaining equipment to assets held for sale and recorded a $3.5 million loss representing the write down to estimated fair market value less estimated costs to sell these assets. (See Note 4 to the Consolidated Financial Statements.)

Gain on Disposition of Properties. Our net gain from the sales of assets for 2002 of $16.6 million was primarily related to the settlement agreement with ExxonMobil, where 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, all of which were unproved properties. In 2001, the gain on disposition of properties of $0.9 million is primarily related to the gain of $1.1 million from our sale of a parcel of real estate in Brea, California.

Derivative Gain (Loss). Our derivative loss was $4.7 million in 2002 compared to a gain of $0.2 million in 2001. The derivative loss in 2002 includes mark-to-market losses on derivatives which did not qualify as hedges and ineffectiveness on hedges.

Interest Expense. Interest expense of $37.9 million in 2002 decreased 12% compared to interest expense of $43.0 million in 2001 due to the benefit of our interest rate swaps in 2002 of $5.4 million.

Dividends. Dividends on the TECONS were $6.6 million in 2002 and 2001. The TECONS pay dividends at a rate of 5.75%. (See Note 10 to the Notes to Consolidated Financial Statements.)

Income Tax. We had income tax expense of $18.2 million including current tax of $1.3 million in 2002 compared to a tax benefit of $57.9 million in 2001 which had no current tax. The current tax relates to California State income tax which deferred the use of net operating losses for two years. Our effective income tax rate was 41.7% in 2002 and 40.1% in 2001.

Discontinued Operations. We had a loss from discontinued operations of $13.2 million in 2002 compared to income of $7.4 million in 2001. In 2002, we sold our properties located in Texas, Alabama and Louisiana (Eastern properties) for approximately $9.0 million and recognized a $0.9 million after-tax loss. We also made the decision to sell our Brea-Olinda field in California in 2002 and recognized a $30.5 million loss in connection with writing down the associated assets to their estimated fair value less our costs to sell them. In 2001 the income from discontinued operations consists of after-tax operating income from our Eastern properties and Brea-Olinda field.

YEAR ENDED DECEMBER 31, 2001 COMPARED TO YEAR ENDED DECEMBER 31, 2000

We had a net loss of $79.2 million for 2001, or ($4.73) per diluted share as compared to net income of $11.6 million, or $0.64 per diluted share in 2000.

Revenues

Oil and Gas Revenues. Oil and gas revenues increased 14% to $327.0 million in 2001 from $286.5 million in 2000 principally due to higher commodity prices and lower hedging losses during 2001, partially offset by lower production. The realized oil price in 2001 was $15.92 per Bbl, an increase of $1.69 per Bbl from 2000. Crude oil production averaged 42.5 MBbls/day, a decrease of 2.4 MBbls/day due to an eight-month curtailment of steaming operations in California as well as production shut-ins for facility repairs in 2001. Our hedging losses were $47.6 million in 2001 and $117.7 million in 2000. Natural gas production averaged 30.5 MMcf per day in 2001, declining 10% from 33.8 MMcf per day in 2000. The decline was due to lower domestic production offshore California. The 2001 realized natural gas price was $7.18 per Mcf, which increased 67% from $4.31 per Mcf in 2000.

Costs and Expenses

Costs and Expenses. LOE for 2001 totaled $167.2 million, as compared to $140.2 million for 2000. The 19% increase in LOE from 2000 to 2001 is primarily due to a 67% increase in gas prices in 2001 compared to 2000. We use gas as a feedstock to generate steam which is injected into reservoirs to facilitate the production of heavy California oil. Exploration costs, including geological and geophysical costs, dry hole costs and delay rentals, were $22.1 million in 2001, an increase of $12.3 million from 2000, primarily due to $14.1 million of dry hole costs associated with non-commercial wells drilled onshore California and certain international properties. Depreciation, depletion and amortization increased 21% in 2001 to $71.6 million due to higher depletion rates which were primarily driven by a lower reserve base. General and administrative expense of $36.9 million in 2001 was $3.9 million higher than 2000 primarily due to higher investment advisory fees.

Impairments of Oil and Gas Properties. During 2001, we recorded an impairment totaling $103.5 million on our Santa Clara, Huntington Beach, Pitas Point, Masseko (Congo) and Point Pedernales fields and certain other oil and gas properties. Statement of Financial Accounting Standards ("SFAS") No. 144 requires an impairment

loss be recognized when the carrying value of an asset exceeds the sum of the undiscounted estimated future net cash flows. We recognized an impairment loss equal to the difference between the carrying amount and the fair value of the assets. We had no impairments in 2000. (See Note 2 to the Notes to the Consolidated Financial Statements.)

Restructuring and Severance Charges. We incurred $4.9 million of restructuring and severance charges in 2001 related to the termination of two outsourcing contracts and the reorganization of our exploration and production operations. These costs included termination fees and severance. We had no such costs in 2000. (See Note 5 to the Notes to the Consolidated Financial

Statements.)

Loss on Assets Held for Sale. In 2001, we made the decision not to proceed with our power plant project in Santa Barbara and Kern County, California and transferred our remaining equipment to assets held for sale and recorded a $3.5 million loss representing the write down to estimated fair market value less estimated costs to sell these assets. We had no such costs in 2000. (See Note 4 to the Notes to the Consolidated Financial Statements.)

Other Expenses. Other expenses were $14.9 million in 2001 increased $9.8 million from 2000 principally due to the termination of hedging contracts with Enron and various consulting and legal costs.

Gain on Disposition of Properties. Our net gain from the sales of assets for 2001 was $0.9 million, primarily related to the $1.1 million gain from our sale of real estate in Brea, California. The net gain on sale of assets for 2000 was $0.7 million primarily representing a $0.9 million gain on the sale of our working interest in the Las Cienegas field in California.

Interest Income and Interest Expense. Interest income for 2001 of $1.3 million was earned on the overnight investment of excess cash. Interest income for 2000 of $1.9 million resulted from higher cash balances in 2000. Interest expense of $43.0 million in 2001 increased 15% compared to interest expense of $37.5 million in 2000. The increase is primarily due to the inclusion of a full year of interest for our 9 ?% Senior Subordinated Notes issued in September 2000, offset by a decrease in the use of a line of credit and an increase of interest capitalized.

Dividends. Dividends on the TECONS were $6.6 million in 2001 and 2000. The TECONS pay dividends at a rate of 5.75%. (See Note 10 to the Notes to Consolidated Financial Statements.)

Income Tax. We had an income tax benefit of $57.9 million in 2001 compared to minimal income tax expense in 2000. Our effective income tax rate was 40.1% in 2001 and 40.3% in 2000.

Discontinued Operations. We had income from discontinued operations of $7.4 million in 2001 compared to income of $12.4 million in 2000. This represents our operating income from the Eastern properties sold in 2002 and the Brea-Olinda field sold in 2003.

CAPITAL RESOURCES AND LIQUIDITY

We have grown and diversified our operations through low-cost 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 $122.7 million, $88.9 million and $94.5 million in 2002, 2001 and 2000. We invested $74.5 million, $133.2 million and $105.2 million in oil and gas properties in 2002, 2001 and 2000. Additionally, we spent $5.7 million, $8.6 million, and $3.4 million on other properties in 2002, 2001 and 2000.

In 2002, we acquired Athanor Resources, Inc. for approximately $101.4 million including $61.3 million of available cash. In 2001, we acquired a producing property in California for $28.5 million.

We believe our working capital, cash flow from operations and available financing sources are sufficient to meet our obligations as they become due and to finance our capital budget through 2003. Under our Credit Agreement which provides for secured revolving credit, we have a $175.0 million borrowing base with $146.3 million available and undrawn at December 31, 2002 and had drawn $28.7 million under the agreement. In late December 2001, and early January 2002, we entered into interest rate swaps totaling $200 million; $150.0 million on our 9 3/8% Notes and $50.0 million on our 9 1/2% Notes. In late August and early September 2002, we terminated our swap transactions relating to these Notes and received $12.1 million which will be amortized as a credit to interest expense through 2008 and 2010. In late August and early November 2002, we entered into interest rate swaps totaling $100.0 million on our 9 3/8% Notes. (See Item 7A, Qualitative and Quantitative Disclosures About Market Risk).

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
			(In thousands)	
Long-term debt	$ 409,577	$ --	$ --	$ 2,367
Operating leases	8,879	1,789	3,629	2,444
Capital commitments	493	493	--	--
Total contractual cash obligations	$ 418,949	$ 2,282	$ 3,629	$ 4,811

Long-term Debt

The following table details our long-term debt (excluding outstanding borrowings under our bank credit facility and interest rate swaps) at December 31:

	2002
	(In thousands)
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
Long-term debt	$ 409,577

9 3/8% Notes due 2010. In 2000, we issued $150.0 million of 9 3/8% Senior Subordinated Notes due October 1, 2010. Interest on these Notes accrues at 9 3/8% per annum and is payable semi-annually in arrears on April 1 and October 1. The Notes are redeemable, in whole or in part, at our option, on or

after October 1, 2005, under certain conditions. We are not required to make mandatory redemption or sinking fund payments with respect to these Notes. The Notes are unsecured general obligations, and are subordinated in right of payment to all existing and future senior indebtedness. In the event of a defined change in control, we will be required to make an offer to repurchase all outstanding 9 3/8% Notes at 101% of the principal amount, plus accrued and unpaid interest to the date of redemption.

9 1/2% Notes due 2008. In July 1999, we authorized a new issuance of $260.0 million of 9 1/2% Senior Subordinated Notes due June 1, 2008. In August 1999, we exchanged $157.5 million of our 9 1/2% Notes due 2006 and $99.9 million of our 8 7/8% Senior Subordinated Notes due 2008. In connection with the exchange offers, we solicited consents to proposed amendments to the indentures under which the exchanged notes were issued. Interest on these Notes accrues at the rate of 9 1/2% per annum and is payable semi-annually in arrears on June 1 and December 1. These Notes are redeemable, in whole or in part, at our option, on or after June 1, 2003, under certain conditions. We are not required to make mandatory redemption or sinking fund payments on these Notes. The 9 1/2% Notes are unsecured general obligations, and are subordinated in right of payment to all existing and future senior indebtedness. In the event of a defined change in control, we will be required to make an offer to

repurchase all outstanding Notes at 101% of the principal amount, plus accrued and unpaid interest to the date of redemption.

9 1/2% Notes due 2006. In 1996, we issued $160.0 million of 9 1/2% Notes and in 1999, we exchanged $157.5 million of these Notes for 9 1/2% Notes due 2008 and have repurchased some of the Notes in the open market. Interest on these Notes accrues at the rate of 9 1/2% per annum and is payable semi-annually in arrears on April 15 and October 15 and are redeemable, in whole or in part, at our option, on or after April 15, 2001, under certain conditions. These Notes have not been redeemed, in whole or in part, at December 31, 2002. We are not required to make mandatory redemption or sinking fund payments with respect to these Notes and they are unsecured general obligations, and are subordinated in right of payment to all existing and future senior indebtedness.

Operating Leases

We have operating leases in the normal course of business, which include those for office space and operating facilities and office and operating equipment, with varying terms from 2002 to 2009. At December 31, 2002, our total commitments under operating leases were approximately $8.9 million.

Minimum annual rental commitments at December 31, 2002, were as follows:

	Operating Leases (In thousands)
2003	$ 1,789

2004	1,833
2005	1,796
2006	1,475
2007	969
Thereafter	1,017
Total	$ 8,879

Capital Commitments

At December 31, 2002, we had capital commitments of $0.5 million relating to our international oil and gas exploration and development activity. In early 2003, we fulfilled this obligation. Our other planned capital projects are discretionary in nature, with no substantial capital commitments made in advance of the actual expenditures.

COMMERCIAL COMMITMENTS

The following table summarizes our Commercial Commitments by date of expiration. Each of these commitments is discussed in further detail below:

	Amount of Commitment Expiration Per Period			
	Total Amount Committed	Less than 1 Year	1 - 3 Years	4 -5 Years
	(in thousands)			
Bank credit facility	$ 28,700	$ --	$ 28,700	$ --
Letters of credit	800	800	--	--
Total commercial commitments	$ 29,500	$ 800	$ 28,700	$ --

Lines of Credit

Bank Credit Facility. Our Third Amended and Restated Credit Agreement, dated June 7, 2000, provides for secured revolving credit availability of up to $250 million and issuance of letters of credit from a bank group led by Bank of America, N.A., Bank One, N.A., and Bank of Montreal until its expiration on June 7, 2005.

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 judgement 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 $175.0 million borrowing base under our Credit Facility with $146.3 million available at December 31, 2002 and had drawn $28.7 million under the agreement. Amounts outstanding under the credit facility bear interest at a rate equal to the London Interbank Offered Rate ("LIBOR") plus an amount which varies according to our Indebtedness to Capitalization ratio (as defined under the Credit Agreement).

Letters of Credits

We had one letter of credit outstanding at December 31, 2002 in the amount of $0.8 million, which expires in August 2003.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Oil and Gas Properties

We use the successful efforts method to account for our investments in oil and gas properties. Under the successful efforts method, oil and gas lease acquisition costs and intangible drilling costs associated with exploration efforts that result in the discovery of proved reserves and costs associated with development drilling, whether or not successful, are capitalized when incurred. When a proved property is sold, ceases to produce or is abandoned, a gain or loss is recognized. When an entire interest in an unproved property is sold for cash or cash equivalent, a gain or loss is recognized, taking into consideration any recorded impairment. When a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained.

Costs of successful wells, development dry holes and proved leases are capitalized and depleted on a unit-of-production basis over the remaining proved reserves. Capitalized drilling costs are depleted on a unit-of-production basis over the lives of the remaining proved developed reserves. Total estimated costs of $177.6 million for future dismantlement, abandonment and site remediation are included when calculating depreciation and depletion using the unit-of-production method. Through December 31, 2002, we had recorded $81.4 million as a component of accumulated depreciation, depletion and amortization related to this future obligation. See Note 2 to the Consolidated Financial Statements for a discussion of the provisions of SFAS No. 143, which will be adopted effective January 1, 2003.

In October 2001, the Financial Accounting Standards Board ("FASB") issued 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 4 to the Notes to the Consolidated Financial Statements).

In accordance with SFAS No. 144, we review our long-lived assets to be held and used, including proved oil and gas properties accounted for using the successful efforts method of accounting, on a depletable unit basis whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. SFAS No. 144 requires an impairment loss to be recognized when the carrying amount of an asset exceeds the sum of the undiscounted estimated future net cash flows and we recognize an impairment loss equal to the difference between the carrying value and the fair value of the asset. Fair value is estimated to be the expected present value of future net cash flows from proved reserves, utilizing a risk-free rate of return. During 2001, we recorded an impairment totaling $103.5 million on our Santa Clara, Huntington Beach, Pitas Point, Masseko (Congo) and Point Pedernales fields and certain other oil and gas properties. We recorded no impairments in 2000 and only those required to be taken for the assets designated as held for sale in 2002. Also, in accordance with SFAS No. 144, when the proved properties are classified as held for sale, if the carrying amount of the assets is less than their fair market value less our estimated costs to sell them, the difference is recognized as a loss in that period and, if significant, the associated results of operations are accounted for as discontinued.

Unproved leasehold costs are capitalized pending the results of exploration efforts. Significant 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. Exploration costs, including geological and geophysical expenses, exploratory dry holes and delay rentals are charged to expense as incurred.

During 2002 and 2001, interest costs associated with non-producing leases and exploration and development projects were capitalized only for the period that activities were in progress to bring these projects to their intended use. The capitalization rates were based on our weighted average cost of funds used to finance expenditures. We capitalized $1.9 million and $2.5 million of interest costs in 2002 and 2001. There were no interest costs capitalized in 2000.

Recognition of Crude Oil and Natural Gas Revenue

Crude oil and natural gas revenue is recognized when title passes to the purchaser. We use the entitlement method for recording sales of crude oil and natural gas from producing wells. Under the entitlement method, revenue is recorded based on our net revenue interest in production. Deliveries of crude oil and natural gas in excess of our net revenue interests are recorded as liabilities and under-deliveries are recorded as assets. Production imbalances are recorded at the lower of the sales price in effect at the time of production or the current market value. Substantially all such amounts are anticipated to be settled with production in future periods. We did not have a material imbalance position in terms of units or value at December 31, 2002 or 2001.

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 options to hedge the impact market price risk exposures on our crude oil and natural gas production, natural gas purchases and to mitigate our exposure to interest rate risk. We account for derivatives under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and have elected to designate derivative instruments that qualify for hedge accounting as cash flow hedges (for commodity related contracts) and fair value hedges (for interest rate contracts).

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, in the fourth quarter 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 on January 1, 2002. We recorded $19.7 million of goodwill in connection with our acquisition of Athanor Resources, Inc. (See Note 3). The goodwill is recorded in our domestic reporting unit. The annual impairment test will be performed in the fourth quarter of each year, or more often if required.

Oil and Gas Reserves

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

NEW ACCOUNTING PRONOUNCEMENTS

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 eventual 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 will adopt the provisions of SFAS No. 143 effective January 1, 2003. In connection with the initial application of SFAS No. 143, it is expected we will record a cumulative effect of change in accounting principle, net of taxes, of approximately $10 million to $15 million as an increase to net income, which will be reflected in our results of operations for 2003. In addition, it is expected we will record an asset retirement obligation of approximately $75 million to $80 million.

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.

Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of the Indebtedness of Others. In November 2002, the FASB issued Interpretation No. 45 ("FIN 45"), Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of the Indebtedness of Others, which clarifies the requirements of SFAS No. 5, Accounting for Contingencies, relating to a guarantor's accounting for and disclosures of certain guarantees issued. FIN 45 requires enhanced disclosures for certain guarantees. It also will require certain guarantees that are issued or modified after December 31, 2002, including certain third-party guarantees, to be initially recorded on the balance sheet at fair value. For guarantees issued on or before December 3, 2002, liabilities are recorded when and if payments become probable and estimable. The financial statement recognition provisions are effective prospectively, and we cannot reasonably estimate the impact of FIN 45 until guarantees are issued or modified in future periods, at which time their results will be initially reported in the financial statements.

CONTINGENCIES AND OTHER MATTERS

On December 18, 2002, a lawsuit was filed by Hills for Everyone, a non-profit corporation, against Orange County and Nuevo Energy Company challenging the adequacy of the Environment Impact Report for the Company's Tonner Hills project. The suit seeks to compel Orange County to set aside its decision to adopt the Environment Impact Report and seeks additional environmental analysis and mitigation measures. The Company is contesting the litigation and both the County and the Company are continuing to take the necessary regulatory steps to move the project toward development.

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 which is classified in other revenue and received payment on this claim by year-end 2002. Certain other costs related to repair 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 nine 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 was 3,000 barrels of crude oil and 2.4 MMcf of natural gas in 2001, representing approximately 6% of our daily production. In early July 2001, crude oil production resumed and full gas sales resumed by mid August 2001. 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 six months.

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 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 in 2002 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 $15.3 million gain related to the sale of this unproved property.

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 December 31, 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. 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 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: (i) a disposition by either us or CMS of its respective Congo subsidiary, (ii) either Congo subsidiary's sale of its interest in the Yombo field, (iii) the acquisition of us or CMS by another consolidated group or (iv) 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 $35.4 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 $53.1 million. CMS sold their interest in the Yombo field in 2002, to a U.S. subsidiary of Perenco, S.A. (Perenco), which is awaiting the approval from the government of Congo. The sale was not a triggering event as both CMS and Perenco filed a request for a Closing Agreement with the Internal Revenue Service in accordance with the U.S. consolidated tax return regulations prior to the sale. Further, we do not expect a triggering event to occur with respect to Nuevo, CMS or Perenco, and do not believe the agreement will have a material adverse effect upon us.

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 should 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.

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.

CONTINGENT PAYMENT AND PRICE SHARING AGREEMENTS

In connection with the acquisition from Unocal in 1996 of the properties located in California, we are obligated to make a contingent payment for the years 1998 through 2004 if oil prices exceed thresholds set forth in the agreement with Unocal. Contingent payments are accounted for as a purchase price adjustment to oil and gas properties. The contingent payment will equal 50% of the difference between the actual average annual price received on a field-by-field basis (capped by a maximum price) and a minimum price, less ad valorem and production taxes, and certain other permitted deductions, multiplied by the actual number of barrels of oil sold that are produced from the properties acquired from Unocal during the respective year. The minimum price of $17.75 per Bbl under the agreement (determined based on the near month delivery of WTI crude oil on the NYMEX) is escalated at 3% per year and the maximum price of $21.75 per Bbl on the NYMEX is escalated at 3% per year. Minimum and maximum prices are reduced to reflect the field level price by subtracting a fixed differential established for each field. The reduction was established at approximately the differential between actual sales prices and NYMEX prices in effect in 1995 ($4.34 per Bbl weighted average for all the properties acquired from Unocal). We accumulate credits to offset the contingent payment when prices are $0.50 per Bbl or more below the minimum price. On March 15, 2002, we paid $10.8 million to Unocal attributable to calendar year 2001 and recorded the payment in oil and gas properties. In March 2003, we advised Unocal that we had failed to take deductions to the purchase price that we believe are permitted by the agreement. Application of these deductions resulted in no payment due for either calendar year 2001 or 2002, and resulted in a credit being available to use against future obligations. Unocal disputes this position. Discussions are taking place between the companies in an effort to resolve this issue for both years. While the final outcome of this matter is not presently determinable, its resolution is not expected to have a significant impact on our operating results, financial condition or liquidity.

In connection with the acquisition of the Congo properties in 1995, we entered into a price sharing agreement with the seller. Under the terms of the agreement, if the average price received for the oil production during the year is greater than the benchmark price established by the agreement, we are obligated to pay the seller 50% of the difference between the benchmark price and the actual price received, for all the production associated with this acquisition. The benchmark price was $15.96 per Bbl for 2002, $15.78 per Bbl for 2001 and $15.19 per Bbl for 2000. The benchmark price increases each year, based on the increase in the Consumer Price Index. For 2002, the effect of this agreement was that we only owned upside above $15.96 per Bbl on approximately 66% of our Congo production. We were obligated to pay the seller $4.1 million in 2002, $3.4 million in 2001 and $5.4 million in 2000 under this price sharing agreement. Because there is no termination date associated with this agreement, it is accounted for as an oil royalty.

We acquired a 12% working interest in the Point Pedernales oil field from Unocal in 1994 and the remainder of our 80.3 % working interest from Torch in 1996. We are entitled to all revenue proceeds up to $9.00 per Bbl, with the excess revenue over $9.00 per Bbl, if any, shared with the original owners from whom Torch acquired its interest. We own amounts below $9.00 per Bbl with the other working interest owners based on their respective ownership interests. For 2002, the effect of this agreement is that we were entitled to receive the pricing upside above $9.00 per Bbl on approximately 73% of the gross Point Pedernales production. As of December 31, 2002, we had $0.5 million accrued as our obligation under this agreement. As of December 31, 2001, we had $0.2 million accrued as our obligation under this agreement. As of December 31, 2000, we had $0.6 million accrued as our obligation under this agreement. Obligations under this agreement are accounted for as an oil royalty.

RISK FACTORS AND 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.

VOLATILITY OF OIL AND GAS PRICES

Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond our control. These factors include but are not limited to weather conditions in the United States, the condition of the United States economy, the actions of the Organization of Petroleum Exporting Countries ("OPEC'), governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, the price of foreign oil imports and the availability of alternate fuel sources and transportation interruption. Any substantial and extended decline in the price of oil or gas would have an adverse effect on the carrying value of our proved reserves, borrowing capacity, our ability to obtain additional capital, and our revenues, profitability and cash flows from operations.

Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and divestiture and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

PRICING OF HEAVY OIL PRODUCTION

A portion of our production is California heavy oil. The market price for California heavy oil differs substantially from the established market indices for oil and gas, principally due to the higher transportation and refining costs associated with heavy oil. As a result, the price received for heavy oil is generally lower than the price for medium and light oil, and the production costs associated with heavy oil are relatively higher than for lighter grades. The margin (sales price minus production costs) on heavy oil sales is generally less than that of lighter oil, and the effect of material price decreases will more adversely affect the profitability of heavy oil production compared with lighter grades of oil. (See "Risk Management and Hedging Policy" below for discussion of our crude oil sales contract which expires in 2013).

RESERVE REPLACEMENT RISKS

Our future performance depends upon the ability to find, develop and acquire additional oil and gas reserves that are economically recoverable. Without successful exploration, exploitation or acquisition activities, our reserves and revenues will decline. No assurances can be given that we will be able to find and develop or acquire additional reserves at an acceptable cost.

The successful acquisition and development of oil and gas properties requires an assessment of recoverable reserves, future oil and gas prices and operating costs, potential environmental and other liabilities and other factors. Such assessments are necessarily inexact and their accuracy inherently uncertain. In addition, no assurances can be given that our exploitation and development activities will result in any increase in reserves. Our operations may be curtailed, delayed or canceled as a result of lack of adequate capital and other factors, such as title problems, weather, compliance with governmental regulations or price controls, mechanical difficulties or

shortages or delays in the delivery of equipment. In addition, the costs of exploitation and development may materially exceed initial estimates.

SUBSTANTIAL CAPITAL REQUIREMENTS

We make, and will continue to make, substantial capital expenditures for the exploitation, exploration, acquisition and production of oil and gas reserves. Historically, these expenditures were financed with cash generated by operations, proceeds from bank borrowings and the proceeds of debt and equity issuances. We believe that we will have sufficient cash provided by operating activities and borrowings under our bank credit facility to fund planned capital expenditures. If revenues or our borrowing base decrease as a result of lower oil and gas prices, operating difficulties or declines in reserves, we may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that additional debt or equity financing or cash generated by operations will be available to meet these requirements.

UNCERTAINTY OF ESTIMATES OF RESERVES AND FUTURE NET CASH FLOWS

Estimates of economically recoverable oil and gas reserves and of future net cash flows are based upon a number of variable factors and assumptions, all of which are to some degree speculative and may vary considerably from actual results. Therefore, actual production, revenues, taxes, and development and operating expenditures may not occur as estimated. Future results of operations will depend upon our ability to develop, produce and sell our oil and gas reserves. The reserve data included herein are estimates only and are subject to many uncertainties. Actual quantities of oil and gas may differ considerably from the amounts set forth herein. In addition, different reserve engineers may make different estimates of reserve quantities and cash flows based upon the same available data.

OPERATING RISKS

Our operations are subject to risks inherent in the oil and gas industry, such as blowouts, cratering, explosions, uncontrollable flows of oil, gas or well fluids, fires, pollution, earthquakes and other environmental risks. These risks could result in substantial losses due to injury and loss of life, severe damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations. Our offshore operations are subject to a variety of operating risks peculiar to the marine environment, such as hurricanes or other adverse weather conditions, to more extensive governmental regulation, including regulations that may, in certain circumstances, impose strict liability for pollution damage, and to interruption or termination of operations by governmental authorities based on environmental or other considerations. Our operations could result in liability for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. We could be liable for environmental damages caused by previous property owners. As a result, substantial liabilities to third parties or governmental entities may be incurred, the payment of which could have a material adverse effect on our financial condition and results of operations. We maintain insurance coverage for our operations, including limited coverage for sudden environmental damages and for existing contamination, but do not believe that insurance coverage for environmental damages that occur over time or insurance coverage for the full potential liability that could be caused by sudden environmental damages is available at a reasonable cost, and we may be subject to liability or may lose substantial portions of our properties in the event of certain environmental damages.

FOREIGN INVESTMENTS

Our foreign investments involve risks typically associated with investments in emerging markets such as uncertain political, economic, legal and tax environments and expropriation and nationalization of assets. 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 protecting against such risks.

Our international assets and operations are subject to various political, economic and other uncertainties, including, among other things, the risks of war, expropriation, nationalization, renegotiation or nullification of existing contracts, taxation policies, foreign exchange restrictions, changing political conditions, international

monetary fluctuations, currency controls and foreign governmental regulations that favor or require the awarding of drilling contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. In addition, if a dispute arises with foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons, especially foreign oil ministries and national oil companies, to the jurisdiction of the United States.

Our private ownership of oil and gas reserves under oil and gas leases in the United States differs distinctly from our ownership of foreign oil and gas properties. In the foreign countries in which we do business, the state generally retains ownership of the minerals and consequently retains control of (and in many cases, participates in) the exploration and production of hydrocarbon reserves. Accordingly, operations outside the United States, and estimates of reserves attributable to properties located outside the United States, may be materially affected by host governments through royalty payments, export taxes and regulations, surcharges, value added taxes, production bonuses and other charges.

RISK MANAGEMENT AND HEDGING POLICY

Our risk management policy is based on the view that oil prices revert to a mean price over the long term. To the extent that future markets over a forward 18 month period are significantly higher than long term norms, we will hedge production volumes up to certain maximums set forth in our oil hedging policy approved by our Board in March 2002. Maximum hedged volumes increase as the price of oil increases. Variations from this policy require Board approval. The risk management policy states that hedging activity that is speculative or otherwise unrelated to our normal business activities is considered inappropriate. We recognize the risks inherent in price management. In order to minimize such risk, we have instituted a set of controls addressing approval authority, trading limits and other control procedures. All hedging activity is the responsibility of our Senior Vice President of Planning and Asset Management. In addition, Internal Audit, which independently reports to the Audit Committee, reviews our risk management activity.

We reduce our exposure to price volatility by hedging our production through swaps, options and other commodity derivative instruments. In a typical swap transaction, we will have the right to receive from the counterparty to the hedge the excess of the fixed price specified in the hedge contract and a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the fixed price, we are required to pay the counterparty the difference. We would be required to pay the counterparty the difference between such prices regardless of whether our production was sufficient to cover the quantities specified in the hedge. Since there is not an established pricing index for hedges of California heavy crude oil production, and the cash market for heavy oil production in California tends to vary widely from index prices typically used in oil hedges, we have entered into a physical sales contract to tie our California production to a traded NYMEX index. As such, in February 2000, we entered into a 15-year contract, effective January 1, 2000, to sell substantially all of our current and future California crude oil production to ConocoPhillips Corporation. The contract provides pricing based on a fixed percentage of the NYMEX crude oil price for each type of crude oil that we produce in California. Consequently, the actual price received by the Company as a percentage of NYMEX will vary with our production mix. Based on our current production mix, the price we receive for our California oil production is expected to average approximately 74% of WTI. While the contract does not reduce our exposure to price volatility, it does effectively eliminate the basis differential risk between the NYMEX price and the field price of our California oil production, thereby facilitating the ability to effectively hedge our realized prices.

INSURANCE

The ability to secure certain insurance coverages at prices that we consider reasonable may be impacted and other coverages or endorsements may not be made available. No assurance can be given that we will be able to duplicate our current insurance package when our policies come up for renewal.

COMPETITION/MARKETS FOR PRODUCTION

We operate in the highly competitive areas of oil and gas exploration, exploitation, development and production. The availability of funds and information relating to a property, the minimum projected return on investment, the availability of alternate fuel sources and the intermediate transportation of oil and gas are factors which affect our ability to compete in the marketplace. Our competitors include major integrated oil companies and a substantial number of independent energy companies, many of which possess greater financial and other resources than we do.

Our heavy crude oil production in California requires special processing treatment available only from a limited number of refineries. Substantial damage to such a refinery or closures or reductions in capacity due to financial or other factors could adversely affect the market for our heavy crude oil production.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk, including adverse changes in commodity prices and interest rates.

Commodity Price Risk. We produce and sell crude oil, natural gas and natural gas liquids, therefore our operating results can be significantly affected by fluctuations in commodity prices caused by changing market forces. We reduce our exposure to price volatility by hedging our production through swaps, put options, collars and other commodity derivative instruments. In a typical swap transaction, if the floating price is less than the fixed price, we will have the right to receive from the counterparty to the hedge the excess of the fixed price specified in the hedge contract and a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the fixed price, we are required to pay the counterparty the difference. In a typical put option contract, we purchase the right to receive from the counterparty the difference, if any, between a fixed price specified in the option less a floating market price. If the floating price is above the fixed price, we are not entitled to a payment. A collar contract works similarly as a put; however, we are required to pay the difference between the floating price and ceiling strike price of the collar if the floating price exceeds the ceiling price. Quantities covered by crude hedges are based on West Texas Intermediate ("WTI") barrels. Prices received for our production is expected to average 74% of WTI, therefore, each WTI barrel effectively hedges 1.35 barrels of our production. We use hedge accounting for these instruments, and settlements of gains or losses on these contracts are reported as a component of oil and gas revenues and operating cash flows in the period realized. These agreements expose us to counterparty credit risk to the extent that the counterparty is unable to meet their settlement commitments to us.

At December 31, 2002, we had entered into the following cash flow hedges:

Crude Oil Hedges

Swaps for Sales	Volume MBbls/day	WTI Price ($Bbl.)
1Q03	15,000	$ 24.40
2Q03	12,000	23.86
3Q03	11,000	23.58
4Q03	9,000	23.42
1Q04	7,000	23.62
2003 (1Q-4Q)	2,500	23.80
2004 (1Q-4Q)	4,500	22.82
2005 (1Q-4Q)	4,500	22.14
Collars		
2003 (1Q-4Q)	10,000	$22.00 - $28.91

Natural Gas Hedges

Swaps for Sales	Volume MMBtu/day	Price (MMBtu)	In
1Q03	6,000	$ 4.76	Waha
2003 (1Q-4Q)	2,000	4.15	W
2004 (1Q-4Q)	3,000	3.91	W
Collars			
2003 (1Q-4Q)	6,000	$ 3.70 - $4.30	W

Swaps for Purchases

2004 (1Q-4Q)	8,000	$ 3.91	So
2005 (1Q-4Q)	8,000	3.85	So

At December 31, 2002, the fair market value of these hedge positions was a loss of $22.3 million. A 10% increase in the underlying commodity prices would increase this loss by $22.1 million.

Subsequent to December 31, 2002, we entered into the following cash flow hedges utilizing swap agreements:

Crude Oil Hedges

Swaps for Sales	Volume MBbls/day	WTI Price ($Bbl.)
4Q03	1,500	$ 25.05
1Q04	2,000	25.00
2Q04	7,000	24.47
3Q04	5,000	24.11

Natural Gas Hedges

Swaps for Sales	Volume MMBtu/day	Price (MMBtu)	In
2Q03	5,500	$ 6.00	Waha &
3Q03	5,500	5.50	Waha &
4Q03	5,500	5.46	Waha &
1Q04	8,500	5.15	Waha &

The fair market value of our hedges was a loss of approximately $19 million at March 20, 2003.

Interest Rate Risk. We may enter into financial instruments such as interest rate swaps to manage the impact of changes in interest rates. Our exposure to changes in interest rates results primarily from our long-term debt with both fixed and floating interest rates.

In late December 2001 and early 2002, we entered into three interest rate swap agreements with notional amounts totaling $200 million to hedge the fair value of our 9 1/2% Notes due 2008 and our 9 3/8% Notes due 2010. These swaps were designated as fair value hedges and were reflected as an increase or decrease of long-term debt with a corresponding increase in 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 of $9.6 million on our 9 3/8% Notes and $0.5 million in accrued interest and the present value of the swap option of $2.5 million on our 9 1/2% Notes. The remaining gain of $9.6 million on our 9 3/8% Notes and $2.5 million on our 9 1/2% Notes continues to be reflected as an increase of long-term debt and is being amortized as a reduction to interest expense over the life of the Notes. Through December 31, 2002, we had amortized $0.3 million and $0.1 million, respectively.

In late August and early November 2002, we entered into two new interest rate swap agreements with notional amounts totaling $50 million each, to hedge a portion of the fair value of our 9 3/8% Notes due 2010. These swaps were designated as fair value hedges and are reflected as an increase of long-term debt of $2.2 million as of December 31, 2002, with a corresponding increase in long-term assets. Under the terms of the first agreement, the counterparty pays us a weighted average fixed annual rate of 9 3/8% on total notional amounts 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%. Under the terms of the second agreement, the counterparty pays us a weighted average fixed annual rate of 9 3/8% on total notional amounts 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 4.95%. At December 31, 2002, our interest rate swaps had a fair value of $2.2 million.

The following table presents principal amounts and the related average interest rates (exclusive of fair value hedges) by year of maturity for our debt obligations at December 31, 2002:

	2003	2004	2005	2006	Thereafter
			(in thousands, except percentages)		
Long-term debt					
Variable rate	--	--	$ 28,700	--	--
Average interest rate	--	--	3.81%	--	--
Fixed rate	--	--	--	$ 2,367	$ 407,210
Average interest rate	--	--	--	9.50%	9.45

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS AND SCHEDULES

INDEPENDENT AUDITORS' REPORT

The Board of Directors and Stockholders
Nuevo Energy Company:

We have audited the accompanying consolidated balance sheets of Nuevo Energy Company and subsidiaries as of December 31, 2002 and 2001, and the related consolidated statements of income, stockholders' equity, cash flows and comprehensive income for each of the years in the three-year period ended December 31, 2002. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Nuevo Energy Company and subsidiaries as of December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

As also discussed in Note 2 to the consolidated financial statements, effective January 1, 2000, the Company changed its method of accounting for its processed fuel oil and natural gas liquids inventories. As discussed in Note 2, effective January 1, 2001, the Company changed its method of accounting for derivative instruments.

KPMG LLP

Houston, Texas
March 17, 2003

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

	Year Ended	
	2002	2
Revenues		
Crude oil and liquids	$ 285,218	$
Natural gas	33,768	
Other	4,070	
	323,056	
Costs and Expenses		
Lease operating expenses	138,017	
Exploration costs	4,541	
Depreciation, depletion and amortization	75,311	
Impairment of oil and gas properties	--	

General and administrative expenses	25,877	
Restructuring and severance charges	--	
Loss on assets held for sale	1,253	
Other	1,931	
Loss (gain) on disposition of properties	(16,588)	
	230,342	
Operating Income (Loss)	92,714	
Derivative gain (loss)	(4,746)	
Interest income	266	
Interest expense	(37,943)	
Dividends on TECONS	(6,613)	
Income (Loss) From Continuing Operations Before Income Taxes	43,678	(
Income Tax Expense (Benefit)		
Current	1,330	
Deferred	16,884	
	18,214	
Income (Loss) From Continuing Operations	25,464	
Income (loss) from discontinued operations, including gain/loss on disposal, net of income taxes	(13,189)	
Cumulative effect of a change in accounting principle, net of income tax benefit of $537	--	
Net Income (Loss)	$ 12,275	$
Earnings Per Share:		
Basic		
Income (Loss) from continuing operations	$ 1.44	$
Income (Loss) from discontinued operations, net of income taxes	(0.74)	
Cumulative effect of a change in accounting principle, net of income tax benefit	--	
Net income (loss)	$ 0.70	$
Diluted		
Income (Loss) from continuing operations	$ 1.43	$
Income (Loss) from discontinued operations, net of income taxes	(0.74)	
Cumulative effect of a change in accounting principle, net of income tax benefit	--	
Net income (loss)	$ 0.69	$
Weighted Average Shares Outstanding:		
Basic	17,651	
Diluted	17,790	

See accompanying notes.

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

ASSETS

Current assets
Cash and cash equivalents ....
Accounts receivable, net of allowance of $626 in 2002 and $1,280 in 2001 ....
Inventory ....
Assets held for sale ....
Price risk management activities ....
Deferred income taxes ....
Prepaid expenses and other ....

Total current assets ....

Property and equipment, at cost
Land ....
Oil and gas properties (successful efforts method) ....
Gas plant and other facilities ....

Accumulated depreciation, depletion and amortization ....

Total property and equipment, net ....

Deferred income taxes ....
Goodwill ....
Other assets ....

Total assets ....

LIABILITIES AND STOCKHOLDERS' EQUITY

Current liabilities
Accounts payable ....
Accrued interest ....
Accrued drilling costs ....
Accrued lease operating costs ....
Deferred income tax ....
Price risk management activities ....
Other accrued liabilities ....

Total current liabilities ....

Long-Term debt
Senior Subordinated Notes ....
Bank Credit Facility ....

Total debt ....
Interest rate swaps - fair value adjustment ....
Interest rate swaps - termination gain ....

Long-term debt	
Other long-term liabilities	
Company-Obligated Mandatorily Redeemable Convertible Preferred Securities of Nuevo Financing I (TECONS)	
Commitments and contingencies (Note 12)	
Stockholders' equity	
Preferred stock, $1.00 par value, 10,000,000 shares authorized; 7% Cumulative Convertible Preferred Stock, none issued and outstanding	
Common stock, $0.01 par value, 50,000,000 shares authorized, 23,048,388 and 20,905,796 shares issued and 19,110,102 and 16,880,080 shares outstanding, respectively	
Additional paid-in capital	
Treasury stock, at cost, 3,867,691 and 3,902,721 shares, respectively	
Deferred stock compensation and other	
Accumulated other comprehensive income	
Accumulated deficit	
Total stockholders' equity	
Total liabilities and stockholders' equity	

See accompanying notes.

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

	Year End
	2002
Cash flows from operating activities	
Net income (loss)..	$ 12,275
Adjustments to reconcile net income (loss) to net cash provided by operating activities	
Depreciation, depletion and amortization.......................	75,311
Deferred income taxes..	16,884
Dry hole costs...	297
Amortization of debt financing costs...........................	2,532
Impairment of oil and gas properties...........................	--
Net gain on sales of assets....................................	(16,588)
Loss on assets held for sale	1,253
Non-cash effect of discontinued operations.....................	26,611
Cumulative effect of a change in accounting principle	--
Other..	8,540
Working capital changes, net of non-cash transactions	
Accounts receivable..	9,341
Accounts payable...	(6,578)
Accrued liabilities..	(11,997)

Other	4,847
Net cash provided by operating activities	122,728
Cash flows from investing activities	
Additions to oil and gas properties	(74,472)
Acquisition of Athanor Resources, Inc.	(61,312)
Acquisitions of oil and gas properties	--
Proceeds from sales of properties	26,968
Additions to other properties	(5,698)
Net cash used in investing activities	(114,514)
Cash flows from financing activities	
Proceeds from borrowings	--
Debt issuance and modification costs	--
Net borrowings of credit facility	(12,800)
Payments of long-term debt	--
Proceeds from exercise of stock options	1,229
Purchase of treasury shares	--
Other proceeds	1,294
Net cash provided by (used in) financing activities	(10,277)
Increase (decrease) in cash and cash equivalents	(2,063)
Cash and cash equivalents	
Beginning of year	7,110
End of year	$ 5,047

See accompanying notes.

NUEVO ENERGY COMPANY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(IN THOUSANDS)

	2002		2001	
	Shares	Amount	Shares	Amount
Common Stock				

Balance, beginning of year	16,880	$ 209	16,632	$ 20
Issuances and purchases of common stock				
Acquisition of Athanor Resources, Inc.	1,970	20	--	-
Employee stock compensation and plans	260	1	376	
Purchase of treasury stock	--	--	(128)	-
Balance, end of year	19,110	$ 230	16,880	$ 20
Additional Paid-In Capital				
Balance, beginning of year		$ 366,792		$ 361,64
Acquisition of Athanor Resources, Inc.		20,066		-
Exercise of stock options		1,785		4,46
Employee stock compensation and plans		(164)		68
Balance, end of year		$ 388,479		$ 366,79
Accumulated Deficit				
Balance, beginning of year		$ (138,952)		$ (59,78
Net income (loss)		12,275		(79,17
Balance, end of year		$ (126,677)		$ (138,95
Accumulated Other Comprehensive Income				
Balance, beginning of year		$ 11,534		$ -
Other comprehensive income		(23,002)		11,53
Balance, end of year		$ (11,468)		$ 11,53
Treasury Stock				
Balance, beginning of year		$ (75,855)		$ (74,70
Issuance related to employee stock compensation and plans		172		93
Purchase of treasury stock		--		(2,08
		$ (75,683)		$ (75,85
Deferred Compensation and Other				
Balance, beginning of year		$ (3,821)		$ (4,24
Deferred compensation		1,422		(30
Stock acquired by benefit trust		(172)		(93
Withdrawal from benefit trust		1,966		1,66
Balance, end of year		$ (605)		$ (3,82
Total Stockholders' Equity		$ 174,276		$ 159,90

See accompanying notes.

NUEVO ENERGY COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(IN THOUSANDS)

	Year Ended		
	2002		2
Comprehensive Income			
Net income (loss)	$	12,275	$
Unrealized gains (losses) from cash flow hedging activity:			
Cumulative effect transition adjustment (net of income tax benefit of $10,784 in 2001)		--	
Reclassification adjustment of settled contracts (net of income taxes of $3,262 in 2002 and $19,202 in 2001)		4,753	
Changes in fair value of derivative instruments during the period (net of income tax benefit of $19,049 in 2002 and $632 in 2001)		(27,755)	
Other comprehensive income		(23,002)	
Comprehensive income	$	(10,727)	$

See accompanying notes.

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NUEVO ENERGY COMPANY
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION

Nuevo Energy Company ("Nuevo") was formed as a Delaware corporation on March 2, 1990, to acquire the businesses of certain public and private partnerships (collectively "Predecessor Partnerships"). On July 9, 1990, the plan of consolidation ("Plan of Consolidation") was approved by limited partners owning a majority of units of limited partner interests in the partnerships whereby the net assets of the Predecessor Partnerships, which were subject to the Plan of Consolidation, were exchanged for Common Stock of Nuevo ("Common Stock"). All references to the "Company" include Nuevo and its majority and wholly-owned subsidiaries, unless otherwise indicated or the context indicates otherwise.

We are engaged in the acquisition, exploitation, development, exploration and production of crude oil and natural gas. Our principal oil and gas properties are located domestically onshore and offshore California and West Texas, and internationally offshore the Republic of Congo, West Africa.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

Our consolidated financial statements include the accounts of Nuevo and our majority and wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation.

Oil and Gas Properties

We use the successful efforts method to account for our investments in oil and gas properties. Under the successful efforts method, oil and gas lease acquisition costs and intangible drilling costs associated with exploration efforts that result in the discovery of proved reserves and costs associated with development drilling, whether or not successful, are capitalized when incurred. When a proved property is sold, ceases to produce or is abandoned, a gain or loss is recognized. When an entire interest in an unproved property is sold for cash or cash equivalent, a gain or loss is recognized, taking into consideration any recorded impairment. When a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained.

Costs of successful wells, development dry holes and proved leases are capitalized and depleted on a unit-of-production basis over the remaining proved reserves. Capitalized drilling costs are depleted on a unit-of-production basis over the lives of the remaining proved developed reserves. Total estimated costs of $177.6 million for future dismantlement, abandonment and site remediation are included when calculating depreciation and depletion using the unit-of-production method. At December 31, 2002, we had recorded $81.4 million as a component of accumulated depreciation, depletion and amortization related to this future obligation. See "New Accounting Pronouncements" for a discussion of the provisions of SFAS No. 143, which will be adopted effective January 1, 2003.

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 4).

In accordance with SFAS No. 144, we review our long-lived assets to be held and used, including proved oil and gas properties accounted for using the successful efforts method of accounting, on a depletable unit basis whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. SFAS No. 144 requires an impairment loss to be recognized when the carrying amount of an asset exceeds the sum of the undiscounted estimated future net cash flows and we recognize an impairment loss equal to the difference between the carrying value and the fair value of the asset. Fair value is estimated to be the expected present value of future net cash flows from proved reserves, utilizing a risk-free rate of return. During 2001, we recorded an impairment totaling $103.5 million on our Santa Clara, Huntington Beach, Pitas Point, Masseko (Congo) and Point Pedernales fields and certain other oil and gas properties. We recorded no impairments in 2000 and only those required to be taken for the assets currently designated as held for sale in 2002. Also, in accordance with SFAS No. 144, when the proved properties are classified as held for sale, if the carrying amount of the assets is less than their fair market value less our estimated costs to sell them, the difference, if significant, is recognized as a loss in that period and the associated results of operations are accounted for as discontinued.

Unproved leasehold costs are capitalized pending the results of exploration efforts. Significant 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. Exploration costs, including geological and geophysical expenses, exploratory dry holes and delay rentals, are charged to expense as incurred.

During 2002 and 2001, interest costs associated with non-producing leases and exploration and development projects were capitalized only for the period that activities were in progress to bring these projects to their intended use. The capitalization rates were based on our weighted average cost of funds used to finance expenditures. We capitalized $1.9 million and $2.5 million of interest costs in 2002 and 2001. There were no interest costs capitalized in 2000.

Any reference to oil and gas reserve information in the Notes to the Consolidated Financial Statements is unaudited.

Derivative Financial Instruments and Price Risk Management Activities

We use price risk management activities to manage non-trading market risks. We use derivative financial instruments such as swaps, collars and put options to hedge the impact market price risk exposures on our crude oil and natural gas production and to mitigate our exposure to interest rate risk.

We adopted SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, effective January 1, 2001. This statement requires all derivative instruments to be carried on the balance sheet at fair value. In accordance with the transition provisions of SFAS No. 133, we recorded a cumulative-effect transition adjustment of $(16.0) million, net of related taxes of $10.8 million, in accumulated other comprehensive income to recognize the fair value of our derivatives designated as cash-flow hedging instruments at the date of adoption.

Beginning on January 1, 2001, all of our derivative instruments are recognized on the balance sheet at their fair value. We currently use swaps, collars and put options to hedge our exposure to material changes in the future price of crude oil and natural gas and interest rate swaps to hedge the fair value of our long-term debt.

On the date we enter into a derivative contract, we designate the derivative as either a hedge of the fair value of a recognized asset, liability or firm commitment ("fair value" hedge), or as a hedge of the variability of cash flows to be received or paid ("cash flow" hedge). Changes in the fair value of a derivative that is highly effective as, and that is designated and qualifies as, a fair value hedge, along with the change in fair value of the hedged asset or liability that is attributable to the hedged risk (including losses or gains on firm commitments), are recorded in current period earnings. Changes in the fair value of a cash flow hedge are recorded in other comprehensive income (loss) until the hedged transaction occurs. At December 31, 2002, we had both cash flow hedges and fair value hedges. (See Note 13.)

We formally document all relationships between hedging instruments and hedged items, as well as its risk-management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives that are designated as cash flow hedges to forecasted transactions. We also formally assess, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged transactions. When it is determined that a derivative is not highly effective as a hedge or that it has ceased to be a highly effective hedge, we discontinue hedge accounting prospectively.

When hedge accounting is discontinued because it is probable that a forecasted transaction will not occur, the derivative will continue to be carried on the balance sheet at its fair value, and gains and losses that were accumulated in other comprehensive income will be recognized in earnings immediately. In all other situations in which hedge accounting is discontinued, the derivative will be carried at its fair value on the balance sheet, with changes in its fair value recognized in earnings prospectively.

At December 31, 2002, we had recorded $11.5 million, net of related taxes of $7.9 million, of cumulative hedging losses in other comprehensive income, which will 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 $9.4 million, $47.6 million and $117.7 million in 2002, 2001 and 2000. The portion of our derivative financial instruments that were ineffective or did not qualify for hedge accounting totaled $4.7 million in 2002 and was recorded in derivative gain/loss in the accompanying consolidated statements of income.

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 in the fourth quarter, 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 on January 1, 2002. We recorded $19.7 million of goodwill in connection with our acquisition of Athanor Resources, Inc. (See Note 3). The goodwill is recorded in our domestic reporting unit. The annual impairment test will be performed in the fourth quarter of each year, or more often if required.

Comprehensive Income

Comprehensive income includes net income and all changes in other comprehensive income. Changes in other comprehensive income include changes in the fair value of derivatives designated as cash flow hedges.

Environmental Liabilities

Environmental expenditures that relate to current or future revenues are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, and do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated. Generally, the timing of these accruals coincides with our commitment to a formal plan of action. As of December 31, 2002, we had accrued approximately $5.6 million for future environmental expenditures.

Contingencies

We recognize liabilities for contingencies when we have an exposure that, when fully analyzed, indicates it is both probable and that the amount can be reasonably estimated. Funds spent to remedy these contingencies are charged against a reserve, if one exists, or expensed.

Inventory

Our inventory is valued at the lower of cost or market, with cost being determined on a first-in, first-out (FIFO) method. We had crude oil inventory in the Congo of $3.0 million and $0.8 million at December 31, 2002 and 2001. Our materials and supplies inventory totaled $4.3 million and $3.0 million at December 31, 2002 and 2001.

Prior to December 31, 2000, we recorded inventory relating to quantities of processed fuel oil and natural gas liquids in storage at current market pricing. Also, fuel oil in inventory was stated at year end market prices less transportation costs, and we recognized changes in the market value of inventory from one period to the next as oil revenues. In December 2000, the staff of the Securities and Exchange Commission announced that commodity inventories should be carried at the lower of cost or market rather than at market value. As a result, we changed our inventory valuation method to the lower of cost or market in the fourth quarter of 2000, retroactive to the beginning of the year and recorded a non-cash charge related to this cumulative effect of accounting change, effective January 1, 2000, of $0.8 million, net of related income tax benefit of $0.5 million, to value product inventory at the lower of cost or market.

Gas Plant and Other Facilities

Gas plant and other facilities include the costs to acquire certain gas plant and other facilities and to secure rights-of-way. Capitalized costs associated with gas plant and other facilities are amortized primarily over the estimated useful lives of the various components of the facilities utilizing the straight-line method. The estimated useful lives of such assets range from three to thirty years. We review these assets for impairment whenever events or changes in circumstances indicate that their carrying amounts may not be recoverable.

Recognition of Crude Oil and Natural Gas Revenue

Crude oil and natural gas revenue is recognized when title passes to the purchaser. We use the entitlement method for recording sales of crude oil and natural gas from producing wells. Under the entitlement method, revenue is recorded based on our net revenue interest in production. Deliveries of crude oil and natural gas in excess of our net revenue interests are recorded as liabilities and under-deliveries are recorded as assets. Production imbalances are recorded at the lower of the sales price in effect at the time of production or the current market value. Substantially all such amounts are anticipated to be settled with production in future periods. We did not have a material imbalance position in terms of units or value at December 31, 2002 or 2001.

Income Taxes

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

Statements of Cash Flows

For cash flow presentation purposes, we consider all highly liquid money market instruments with an original maturity of three months or less to be cash equivalents. Interest paid in cash, including amounts capitalized, for 2002, 2001 and 2000 was $35.4 million, $38.3 million and $32.1 million. Net amounts paid (refunded) in cash for income taxes for 2002, 2001 and 2000 were $(1.5) million, $0.4 million and $(0.5) million.

Use of Estimates

In order to prepare these financial statements in conformity with accounting principles generally accepted in the United States of America, our management has made a number of estimates and assumptions relating to the reporting of assets and liabilities and the disclosure of contingent assets and liabilities, as well as reserve information, which affects the depletion calculation. Actual results could differ from those estimates.

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 their market value of the underlying common stock on the date of grant. As allowed by SFAS No. 123, Accounting for Stock-Based Compensation, we have continued to apply APB Opinion No. 25 for purposes of determining net income. In December 2002, the 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:

	Year Ended December	
	2002	2001
	(In thousands, except per s	
Net income (loss) as reported	$ 12,275	$ (79,171)
Add:		
Stock based employee compensation expense included in reported net income, net of related income tax	755	310
Deduct:		
Total stock based employee compensation expense determined under fair value based method for all awards, net of related income tax	(4,777)	(4,316)
Pro forma net income (loss)	$ 8,253	$ (83,177)
Earnings per share:		
Basic - as reported	$ 0.70	$ (4.73)
Basic - pro forma	0.47	(4.97)
Diluted - as reported	0.69	(4.73)
Diluted - pro forma	0.46	(4.97)

The weighted-average fair value of options granted during 2002, 2001 and 2000 was $8.20, $6.23 and $10.87. The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions: expected stock price volatility of 44.5%, 54.5% and 112.0% in 2002, 2001 and 2000; risk free interest of 4%, 4% and 5% in 2002, 2001 and 2000; and average expected option lives of eight years in

2002 and three years in 2001 and 2000.

Functional Currency

Our functional currency for all operations is the U.S. dollar.

Reclassifications

Certain reclassifications of prior period amounts have been made to conform to the current presentation. The unaudited quarterly data footnote (Note 16) also reflects reclassifications to conform with current presentation. These reclassifications had no effect on net income or earnings per share.

New Accounting Pronouncements

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 eventual 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 will adopt the provisions of SFAS No. 143 effective January 1, 2003. In connection with the initial application of SFAS No. 143, it is expected that we will record a cumulative effect of change in accounting principle, net of taxes, of approximately $10 million to $15 million as an increase to net income, which will be reflected in our results of operations for 2003. In addition, it is expected we will record an asset retirement obligation of approximately $75 million to $80 million.

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.

Guarantor's Accounting and Disclosure Requirements. In November 2002, the FASB issued Interpretation No. 45 (FIN 45), Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of the Indebtedness of Others, which clarifies the requirements of SFAS No. 5, Accounting for Contingencies, relating to a guarantor's accounting for and disclosures of certain guarantees issued. FIN 45 requires enhanced disclosures for certain guarantees. It also will require certain guarantees that are issued or modified after December 31, 2002, including certain third-party guarantees, to be initially recorded on the balance sheet at fair value. For guarantees issued on or before December 3, 2002, liabilities are recorded when and if payments become probable and estimable. The financial statement recognition provisions are effective prospectively, and we cannot reasonably estimate the impact of FIN 45 until guarantees are issued or modified in future periods, at which time their results will be initially reported in the financial statements.

3. MERGER WITH ATHANOR RESOURCES, INC.

Effective September 18, 2002, pursuant to an agreement and plan of merger, Nuevo Texas, Inc. one of our wholly owned subsidiaries, acquired Athanor Resources, Inc. (Athanor). In connection with the acquisition, we 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 the 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.

	(In thousands)
Current assets	$ 2,008
Property, plant and equipment	102,801
Goodwill	19,664
Total assets acquired	124,473
Current liabilities	4,599
Long-term debt	20,000
Deferred tax liability	18,477
Total liabilities assumed	43,076
Net assets acquired	$ 81,397

The allocation of the purchase price resulted in approximately $19.7 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 us 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 included capitalizable third party transaction costs.

The merger included certain non-cash investing and financing activities not reflected in the Consolidated 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 of $20.0 million was repaid.

The following unaudited pro forma condensed income statement information has been prepared to give effect to the merger as if the 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.

	2002	2001
	(In thousands, except per share data)	
Revenues	$ 338,613	$ 360,484
Income (loss) from continuing operations	27,773	(77,682)
Net income (loss)	14,584	(70,289)
Earnings per share		
Basic		
Income (loss) from continuing operations	1.45	(4.15)
Net income (loss)	0.76	(3.76)
Diluted		
Income (loss) from continuing operations	1.45	(4.15)
Net income (loss)	0.76	(3.76)

4. ACQUISITIONS AND DIVESTITURES

Discontinued Operations

Eastern Properties. In 2002, we sold a majority of our oil and gas properties located in Texas, Alabama and Louisiana for approximately $9.0 million. We recognized a $0.9 million loss on the sale of these properties. Historical results of operations from these properties and the loss on sale are classified as discontinued operations in our consolidated statements of income. Revenues associated with the sold properties were $3.2 million in 2002, $8.3 million in 2001 and $14.6 million in 2000. Pre-tax income associated with the sold properties totaled $1.0 million in 2002, $4.6 million in 2001 and $6.8 million in 2000.

Brea-Olinda. In December 2002, our Board approved the sale of our Brea-Olinda property located in California. We transferred our remaining basis in the properties to assets held for sale and recognized a $30.5 million loss in connection with writing down these assets to their estimated fair value less our costs to sell them. Historical results of operations from this property and the loss from the write down are classified as discontinued operations in our statements of income. Revenues associated with these properties were $16.4 million in 2002, $18.0 million in 2001 and $20.4 million in 2000. Pre-tax income associated with these properties were $8.0 million in 2002, $7.7 million in 2001 and $14.0 million in 2000. We consummated the sale of the Brea-Olinda oil and gas properties in February 2003.

Continuing Operations

California Real Estate. In December 2002, our Board approved the sale of certain real estate properties located in California. We transferred the remaining basis in this real estate to assets held for sale and recognized a $1.3 million loss in connection with writing down the basis of these properties to their estimated fair value less our costs to sell them.

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Power Plant Project. In late 2001, we made the decision not to pursue our power plant project in Kern County, California due to the inability to secure the required permits. We transferred our remaining equipment to assets held for sale and recognized a $3.5 million loss in connection with writing down the equipment to their estimated fair value less our costs to sell the assets.

Anaguid Permit. In July 2001, we acquired an additional interest in the Anaguid Permit, a 1.1 million-acre permit located onshore southern Tunisia in the Ghadames Basin. Our working interest increased to 22.5%. We relinquished the Anaguid Permit in 2002 and wrote off $2.2 million as exploration costs.

Accra-Keta Permit. In June 2001, we relinquished our 1.9 million-acre Accra-Keta Permit offshore the Republic of Ghana. The Permit was relinquished prior to the commencement of the second phase of the work program. We were the operator of this Permit and held a 50% working interest. An impairment of $1.0 million was recorded in 2001 in connection with this relinquishment.

Kern County Properties. In January 2001, we acquired approximately 2,900 acres of producing properties in Kern County, California for approximately $28.5 million. The acreage is southeast of our interest in the Cymric field, of which more than half is natural gas and provides significant development potential.

Las Cienegas Field. In May 2000, we sold our working interest in the Las Cienegas field in California for approximately $4.6 million. In connection with this sale, we unwound hedges of 2,800 BOPD for the period from May 2000 through December 2000 and recorded an adjusted net gain on sale of approximately $0.9 million.

5. RESTRUCTURING, SEVERANCE AND OUTSOURCING

During 2002, we terminated our California field operations and human resources outsourcing agreements. 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 rolls forward our liability recorded for restructuring and severance obligations related to this termination:

	Liability at December 31, 2001	Payments in 2002	Liability December 2002

	(In thousands)		
Severance, benefits and other	$ 1,675	$ 1,675	$
Contract termination	2,681	2,681	
	$ 4,356	$ 4,356	$

In 2002, we terminated all remaining outsourcing contracts with Torch Energy Advisors Incorporated and their affiliates. Since 1999, they had provided the following services: oil and gas administration (accounting, information technology and land administration), human resources, corporate administration (legal, graphics, support, and corporate insurance), crude oil marketing, natural gas marketing, land leasing and field operations. Under the Master Services Agreement, which contained the overall terms and conditions governing each individual service agreement, we paid Torch $5.9 million, $8.4 million and $13.7 million in 2002, 2001 and 2000. The fees charged for field operations were $7.5 million, $22.3 million and $21.8 million in 2002, 2001 and 2000 and the marketing fees were $0.9 million, $1.9 million and $1.8 million in 2002, 2001 and 2000. We will incur no such fees in 2003.

6. INCOME TAXES

Income tax expense (benefit) is summarized as follows:

	Year Ended December 31,		
	2002	2001	200
		(In thousands)	
Current			
Federal	$ --	$ --	$
State	1,330	--	
	1,330	--	
Deferred			
Federal	15,413	(46,432)	
State	1,471	(11,470)	
	$ 16,884	$ (57,902)	$
Total income tax expense (benefit)	$ 18,214	$ (57,902)	$

We recorded income tax expense (benefit) of $(9.4) million, $4.9 million and $8.4 million in 2002, 2001 and 2000 related to discontinued operations. We recorded a tax benefit of $0.5 million related to a cumulative effect of a change in accounting principle in 2000 (see Note 2). A deferred tax benefit related to the exercise of employee stock options of approximately $0.5 million, $0.8 million and $0.5 million was allocated directly to additional paid-in capital in 2002, 2001 and 2000.

Total income tax expense (benefit) differs from the amount computed by applying the federal income tax rate to income (loss) before income taxes and cumulative effect. The reasons for these differences are as follows:

	Year Ended December 31,	
	2002	2001
Statutory federal income tax rate	35.0%	(35.0)%
Increase (decrease) in tax rate resulting from:		
State income taxes, net of federal benefit	6.6	(5.2)
Nondeductible travel and entertainment and other	0.1	0.1
	41.7%	(40.1)%

The tax effects of temporary differences that result in significant portions of the deferred income tax assets and liabilities and a description of the financial statement items creating these differences are as follows:

	December 31,	
	2002	2001
	(In thousands)	
Net operating loss carryforwards	$ 74,640	$ 57,568
Alternative minimum tax credit carryforwards	200	1,704
Property and equipment	--	3,261
Other accrued liabilities	1,205	5,843
Commodity hedging contracts	7,871	--
State income taxes	2,298	5,268
Total deferred income tax assets	86,214	73,664
Less: valuation allowance	(804)	(1,777)
Net deferred income tax assets	85,410	71,867
Property and equipment	(33,798)	--
Equity in foreign subsidiaries	(671)	(1,854)
Commodity hedging contracts	--	(7,783)
Total deferred income tax liabilities	(34,469)	(9,637)
Net deferred income tax asset	$ 50,941	$ 62,230

At December 31, 2002, we had a net operating loss carryforward for regular tax purposes of approximately $211.0 million, which will begin expiring in 2018. Alternative minimum tax credit carryforwards of $0.2 million do not expire and may be applied to reduce regular income tax to an amount not less than the alternative minimum tax payable in any one year. For all periods presented we concluded that based upon available estimates and tax planning strategies, it was more likely than not that substantially all of the recorded deferred tax assets would be realized.

7. ACCOUNTS RECEIVABLE

Our accounts receivable consisted of the following at December 31:

	2002	2001
	(In thousands)	
Oil and gas sales	$ 31,551	$ 32,220
Joint interest billings	4,070	9,348
Other	5,324	6,736
	$ 40,945	$ 48,304

8. LONG-TERM DEBT

Our long-term debt consisted of the following:

	December 31,	
	2002	2001
	(In thousands)	
9 3/8% Senior Subordinated Notes due 2010	$ 150,000	$ 150,000
9 1/2% Senior Subordinated Notes due 2008	257,210	257,210
9 1/2% Senior Subordinated Notes due 2006	2,367	2,367
Bank credit facility (3.81% on December 31, 2002 and 3.71% on December 31, 2001)	28,700	41,500
Total debt	438,277	451,077
Interest rate swaps - fair value adjustment	2,161	(633)
Interest rate swaps - termination gain	11,673	--
Long-term debt	$ 452,111	$ 450,444

9 3/8% Notes due 2010

On September 26, 2000, we issued $150.0 million of 9 3/8% Senior

Subordinated Notes due October 1, 2010. Interest accrues at 9 3/8% per annum and is payable semi-annually in arrears on April 1 and October 1. The Notes are redeemable, in whole or in part, at our option, on or after October 1, 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. If one of our subsidiaries guarantees other subordinated indebtedness of ours, the subsidiary must also guarantee these Notes. Currently, none of our subsidiaries guarantee subordinated indebtedness of ours. The Notes are unsecured general obligations, and are subordinated in right of payment to all existing and future senior indebtedness. In the event of a defined change in control, we will be required to make an offer to repurchase all outstanding 9 3/8% Notes at 101% of the principal amount, plus accrued and unpaid interest to the date of redemption.

9 1/2% Notes due 2008

In July 1999, we authorized a new issuance of $260.0 million of 9 1/2% Senior Subordinated Notes due June 1, 2008. In August 1999, we exchanged $157.5 million of our 9 1/2% Notes due 2006 and $99.9 million of our 8 7/8% Senior Subordinated Notes due 2008. In connection with the exchange offers, we solicited consents to proposed amendments to the indentures under which the exchanged notes were issued. The exchange was accounted for as a debt modification and the consideration we paid to the holders of the exchanged 9 1/2% Notes due 2006 was $4.7 million and was accounted for as deferred financing costs.

Interest on these Notes accrues at the rate of 9 1/2% per annum and is payable semi-annually in arrears on June 1 and December 1. These Notes are redeemable, in whole or in part, at our option, on or after June 1, 2003, under certain conditions. We are not required to make mandatory redemption or sinking fund payments on these Notes. The indenture contains covenants that, among other things, limit the Company's 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. The 9 1/2% Notes are not currently guaranteed by our subsidiaries but are required to be guaranteed by any subsidiary that guarantees pari passu or subordinated indebtedness. Currently, none of our subsidiaries guarantees our subordinated indebtedness. The 9 1/2% Notes are unsecured general obligations, and are subordinated in right of payment to all of our existing and future senior indebtedness. In the event of a defined change in control, we will be required to make an offer to repurchase all outstanding Notes at 101% of the principal amount, plus accrued and unpaid interest to the date of redemption.

9 1/2% Notes due 2006

In April 1996, we issued $160.0 million of 9 1/2% Notes and in 1999, we exchanged $157.5 million of these Notes for 9 1/2% Notes due 2008 and have repurchased some of the Notes in the open market. In August 1999, we exchanged $157.5 million of these notes for our 9 1/2% Notes due 2008. In October 1999, we purchased $0.1 million of the remaining Notes. No significant costs were incurred in connection with the early retirement of the $0.1 million Notes. Interest on these Notes accrues at the rate of 9 1/2% per annum and is payable semi-annually in arrears on April 15 and October 15 and were redeemable, in whole or in part, at our option, on or after April 15, 2001, under certain conditions. These Notes have not been redeemed, in whole, or in part at December 31, 2002. We are not required to make mandatory redemption or sinking fund payments with respect to these Notes and they are unsecured general obligations, and are subordinated in right of payment to all existing and future senior indebtedness.

Interest Rate Swaps

We entered into interest rate swaps in 2001 and 2002. (See Note 13).

Bank Credit Facility

Our Third Amended and Restated Credit Agreement, dated June 7, 2000, as amended, provides for secured revolving credit availability of up to $250 million and issuance of letters of credit from a bank group led by Bank of America, N.A., Bank One, NA, and Bank of Montreal until its expiration on June 7, 2005. At year-end 2002, we had $28.7 million under the Credit Facility and one letter of credit outstanding in the amount of $0.8 million.

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 judgement 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 $175.0 million borrowing base under our Credit Facility with $146.3 million available at December 31, 2002 and had drawn $28.7 million under the agreement.

Amounts outstanding under the credit facility bear interest at a rate equal to LIBOR plus an amount which varies according to our Indebtedness to Capitalization ratio (as defined in the Credit Agreement). The weighted average interest rate was 3.6% in 2002 and 6.2% in 2001.

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 (earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses) to fixed charge coverage ratio and a funded debt to capitalization ratio. At December 31, 2002, we were in compliance with all covenants of the Credit Agreement.

The amount of scheduled debt maturities during the next five years and thereafter is as follows (amounts in thousands):

2003	$ --
2004	--
2005	28,700
2006	2,367
2007	--
Thereafter	407,210
Total debt maturities	$ 438,277

Based upon the quoted market price, the fair value of the 9 3/8% Notes was estimated to be $149.4 million and $146.8 million at December 31, 2002 and 2001; the fair value of the 9 1/2% Notes due 2010 was estimated to be $264.0 million and $245.6 million at December 31, 2002 and 2001, and the fair value of the 9 1/2% Notes due 2008 was estimated to be $2.4 million and $2.4 million at December 31, 2002 and 2001. The carrying amount of the credit facility approximates its fair value at December 31, 2002.

9. STOCKHOLDERS' EQUITY

Common and Preferred Stock

Our Certificate of Incorporation authorizes the issuance of up to 50 million shares of Common Stock and 10 million shares of Preferred Stock, the terms, preferences, rights and restrictions of which are established by our Board of Directors. All shares of Common Stock have equal voting rights of one vote per share on all matters to be voted upon by stockholders. Cumulative voting for the election of directors is not permitted. Certain restrictions contained in our loan agreements limit the amount of dividends that may be declared. Under the terms of the most restrictive covenant in our indenture for the 9 1/2% Senior Subordinated Notes due 2008 described in Note 8, we and our restricted subsidiaries had $20.5 million available for the payment of dividends and share repurchases at December 31, 2002. We have not paid dividends on our Common Stock and do not anticipate the payment of cash dividends in the immediate future.

EPS Computation

SFAS No. 128, Earnings per Share, requires a reconciliation of the numerator (income) and denominator (shares) of the basic EPS computation to the numerator and denominator of the diluted EPS computation. In 2001, the weighted average shares held by benefit trust of 145,000 are not included in the calculation of diluted loss per share due to their anti-dilutive effect. In 2001, stock options were excluded from the calculation of diluted loss per share due to their anti-dilutive effect. We had 2.1 million and 2.4 million stock options in 2002 and 2000 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 (loss) per share in 2002, 2001 or 2000 due to their anti-dilutive effect. The reconciliation is as follows:

	For the Year Ended December 31			
	2002		2001	
	Net Income	Common Shares	Net Loss	Common Shares
	(In thousands)			
Earnings (loss) before cumulative effect per Common share - Basic	$ 12,275	17,651	$ (79,171)	16,
Effect of dilutive securities:				
Stock options	--	52	--	
Restricted stock	--	24	--	
Shares held by Benefit Trust	(8)	63	--	
Earnings (loss) before cumulative effect per Common share - Diluted	$ 12,267	17,790	$ (79,171)	16,

Treasury Stock Repurchases

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 during 2002. As of December 31, 2002, we had 3.9 million shares of treasury stock.

Shareholder Rights Plan

In 1997, we adopted a Shareholder Rights Plan to protect our shareholders from coercive or unfair takeover tactics. Under the Shareholder Rights Plan, each outstanding share and each share of subsequently issued common stock has attached to it one Right. Generally, in the event a person or group ("Acquiring Person") acquires or announces an intention to acquire beneficial ownership of 15% or more of the outstanding shares of common stock without our prior consent, or we are acquired in a merger or other business combination, or 50% or more of our assets or earning power is sold, each holder of a Right will have the right to receive, upon exercise of the Right, that number of shares of common stock of the acquiring company, which at the time of such transaction will have a market price of two times the exercise price of the Right. We may redeem the Right for $.01 at any time before a person or group becomes an Acquiring Person without prior approval. The Rights will expire on March 21, 2007, subject to earlier redemption by us.

In 2000, we amended the Shareholder Rights Plan to provide that if we receive and consummate a transaction pursuant to a qualifying offer, the provisions of the Shareholder Rights Plan are not triggered. In general, a qualifying offer is an all cash, fully-funded tender offer for all outstanding common shares by a person who, at the commencement of the offer, beneficially owns less than five percent of the outstanding common shares. A qualifying offer must remain open for at least 120 days, must be conditioned on the person commencing the qualifying offer acquiring at least 75% of the outstanding common shares and the per share consideration must exceed the greater of (1) 135% of the highest closing price of the common shares during the one-year period prior to the commencement of the qualifying offer or (2) 150% of the average closing price of the common shares during the 20 day period prior to the commencement of the qualifying offer.

Executive Compensation Plan

In 1997, we adopted a plan to encourage senior executives to personally invest in our stock, and to regularly review executives' ownership versus targeted ownership objectives. These incentives include a deferred compensation plan (the "Plan") that gives key executives the ability to defer all or a portion of their salaries and bonuses and invest in our common stock or make other investments at the employee's discretion. Stock is held in a benefit trust and stock acquired at a discount prior to the 2001 amendment to the Plan is restricted for a two-year period. The Plan was amended in 2001 to remove the discount on investments in our common stock and to provide additional investment alternatives. Target levels of ownership are based on multiples of base salary and are administered by the Compensation Committee of the Board of Directors. Upon withdrawal from the Plan, the obligation to the employee is settled with the invested assets. The Plan applies to certain highly compensated employees and all executives at a level of Vice-President and above. The stock held in the benefit trust (70,595 shares, 122,995 shares and 174,904 shares at December 31, 2002, 2001 and 2000) was accounted for as a liability at market value, with any changes in market value charged or credited to general and administrative expense until July 2002. Using this approach, we recorded a net benefit of $0.2 million and $0.1 million in 2001 and 2000 related to deferred compensation. In July 2002, the Plan was further amended to remove the right to receive withdrawals in cash resulting in a reclassification of the $1.1 million liability into shareholders' equity. The deferred compensation obligation is now classified in shareholders' equity and changes in the fair value of the obligation are not recognized.

Director Compensation

Non-employee directors may elect to receive all or part of an annual cash retainer of $30,000 in restricted shares of our Common Stock at a 33% increase in value. The election must be made in increments of 25% ($7,500). Therefore, for each $7,500 of compensation for which the election is exercised, the director would receive $9,975 in restricted stock. Beginning in 2003, each non-employee director also receives a semi-annual grant of 2,125 restricted shares of our common stock. All restricted shares are subject to a three-year restricted period. Directors

have the option of deferring delivery of restricted shares beyond the three-year period. Directors also receive $1,000 for each committee meeting attended while committee chairmen receive $1,500. Directors may elect to receive restricted shares for committee meetings at a 33% discount.

Stock Incentive Plans

In 1990, we established the 1990 Stock Option Plan; in 1993, the Board of Directors adopted the Nuevo Energy Company 1993 Stock Incentive Plan; and in

1999, the Board of Directors adopted the Nuevo Energy Company 1999 Stock Incentive Plan (collectively, the "Stock Incentive Plans"). In 2001, the Board of Directors adopted the 2001 Stock Incentive Plan as well as individual incentive plans to induce our Senior Vice President and Chief Financial Officer and our Senior Vice President, Planning and Asset Management to accept employment with us. The purpose of the Stock Incentive Plans is to provide our directors and key employees with performance incentives and to provide a means of encouraging these individuals to own our stock.

In November 2002, the Compensation Committee of the Board of Directors approved an increase of 250,000 shares under the 2001 Stock Incentive Plan, increasing the total maximum number of shares subject to options under the Stock Incentive Plans to 5,250,000 shares. Options are granted under the Stock Incentive Plans on the basis of the optionee's contribution to us. No option may exceed a term of more than ten years. Options granted under the Stock Incentive Plans may be either incentive stock options or options that do not qualify as incentive stock options. Our Compensation Committee is authorized to designate the recipients of options, the dates of grants, the number of shares subject to options, the option price, the terms of payment upon exercise of the options, and the time during which the options may be exercised. Options for officers vest over a term of one to three years, as specified by the Compensation Committee. Officers who have met their targeted stock ownership requirement receive accelerated vesting on all options issued prior to October 15, 2001.

The following table details the summary of activity in the stock option plans during the three years ended 2002:

	Options	Weighted-Average Exercise Price
Outstanding at January 1, 2000	2,617,179	$ 22.72
Granted	419,189	$ 15.69
Exercised	(182,925)	$ 13.40
Canceled	(80,525)	$ 34.18
Outstanding at December 31, 2000	2,772,918	$ 21.94
Granted	875,026	$ 15.51
Exercised	(287,000)	$ 12.93
Canceled	(102,525)	$ 33.88
Outstanding at December 31, 2001	3,258,419	$ 20.62
Granted	487,750	$ 14.79
Exercised	(105,675)	$ 11.99
Canceled	(938,245)	$ 29.13
Outstanding at December 31, 2002	2,702,249	$ 16.96

We had options exercisable of 2,053,416 (weighted average exercise price of $17.89), 2,728,494 (weighted average exercise price of $21.80) and 2,361,979 (weighted average exercise price of $23.04) at December 31, 2002, 2001 and 2000. Detail of stock options outstanding and options exercisable at December 31, 2002 follows:

Outstanding Exercisable

Range of Exercise Prices	Number	Weighted-Average Remaining Life (Years)	Weighted-Average Exercise Price	Number	Wei Av Exe P
$10.31 to $15.42	1,190,175	7.90	$ 13.33	548,342	$
$15.50 to $19.63	1,165,124	4.94	16.94	1,158,124	
$20.38 to $29.88	216,950	2.33	23.85	216,950	
$34.00 to $47.88	130,000	4.80	38.99	130,000	
	2,702,249			2,053,416	

10. COMPANY-OBLIGATED MANDATORILY REDEEMABLE CONVERTIBLE PREFERRED SECURITIES OF NUEVO FINANCING I

On December 23, 1996, the Company and Nuevo Financing I, a statutory business trust formed under the laws of the state of Delaware, (the "Trust"), closed the offering of 2.3 million TECONS on behalf of the Trust. The price to the public was $50.00 per TECONS. Distributions began to accumulate from December 23, 1996, and are payable quarterly on March 15, June 15, September 15, and December 15, at an annual rate of $2.875 per TECONS. Each TECONS is convertible at any time prior to the close of business on December 15, 2026, at the option of the holder into shares of common stock at the rate of 0.8421 shares of common stock for each TECONS, subject to adjustment. The sole asset of the Trust as the obligor on the TECONS is $115.0 million aggregate principal amount of 5.75% Convertible Subordinated Debentures ("Debentures") of the Company due December 15, 2026. The Debentures were issued by us to the Trust to facilitate the offering of the TECONS. The TECONS must be redeemed for $50.00 per TECON plus accrued and unpaid dividends on December 15, 2026.

11. SEGMENTS

Our operations consist of the acquisition, exploitation, exploration, development and production of crude oil and natural gas. Our reportable segments are domestic, foreign and other. Financial information by reportable segment is presented below:

	2002			
	Domestic	Foreign	Other(1)	Tota
	(In thousands)			
Revenues	$ 286,870	$ 32,116	$ 4,070	$ 32
Depreciation, depletion and amortization	66,795	6,198	2,318	7
Income (loss) from continuing operations	108,881	11,654	(76,857)	4
Capital expenditures(2)	137,002	1,524	2,956	14
Assets	558,267	52,269	244,635	85

	2001			
	Domestic	Foreign	Other(1)	To
	(In thousands)			
Revenues	$ 291,014	$ 36,020	$ 273	$
Depreciation, depletion and amortization	59,472	10,381	1,776	
Loss from continuing operations	(29,841)	(8,351)	(106,274)	(
Capital expenditures(2)	148,329	20,647	1,262	
Assets	549,083	56,404	234,325	

	2000			
	Domestic	Foreign	Other(1)	Tot
	(In thousands)			
Revenues	$ 245,561	$ 40,944	$ 2,358	$ 28
Depreciation, depletion and amortization	50,203	8,085	954	5
Income (loss) from continuing operations	63,978	14,947	(78,823)	
Capital expenditures(2)	98,530	9,072	980	10
Assets	625,113	103,204	119,707	84

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(1) Other includes corporate income and expenses.

(2) Net of geological and geophysical, delay rentals, non-cash items and other exploration costs.

Credit Risks due to Certain Concentrations

In 2002, 2001 and 2000, we had one customer that accounted for 73%, 63% and 84% of oil and gas revenues. In 2001 and 2000, we had another customer that accounted for 23% and 11% of oil and gas revenues.

We entered into a 15-year contract, effective January 1, 2000, to sell all of our current and future California crude oil production to Tosco Corporation (now ConocoPhillips). The contract provides pricing based on a fixed percentage of the NYMEX crude oil price for each type of crude oil that we produce in California. Effective January 1, 2003, we renegotiated this contract relative to our Point Arguello production, effectively

increasing our price on 10% of our 2003 crude output by 14.5% on the NYMEX price. While the contract does not reduce our exposure to price volatility, it does effectively eliminate the risk of widening basis differential between the NYMEX price and the field price of our California oil production. In doing so, the contract makes it substantially easier for us to hedge our realized prices. The ConocoPhillips contract permits, under certain circumstances, to separately market up to ten percent of our California crude production. We exercised this right in 2001 and 2002 and sold 5,000 BOPD of our San Joaquin Valley oil production to a third party under a one-year contract containing NYMEX pricing. A new contract was entered into for a two-year period on January 1, 2003.

Our revenues are derived principally from uncollateralized sales to customers in the oil and gas industry, therefore, customers may be similarly affected by changes in economic and other conditions within the industry. We have not experienced significant credit losses in such sales. Sales of oil and gas to ConocoPhillips are similarly uncollateralized.

12. COMMITMENTS AND CONTINGENCIES

On December 18, 2002, a lawsuit was filed by Hills for Everyone, a non-profit corporation, against Orange County and Nuevo Energy Company challenging the adequacy of the Environment Impact Report for the Company's Tonner Hills project. The suit seeks to compel Orange County to set aside its decision to adopt the Environment Impact Report and seeks additional environmental analysis and mitigation measures. The Company is contesting the litigation and both the County and the Company are continuing to take the necessary regulatory steps to move the project toward development.

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 which is classified in other revenue and received payment on this claim by year-end 2002. Certain other costs related to repair 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 nine 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 was 3,000 barrels of crude oil and 2.4 MMcf of natural gas in 2001, representing approximately 6% of our daily production. In early July 2001, crude oil production resumed and full gas sales resumed by mid August 2001. 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 six months.

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 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 believed 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 $15.3 million gain related to the sale of this unproved property.

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 December 31, 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: (i) a disposition by either us or CMS of its respective Congo subsidiary, (ii) either Congo subsidiary's sale of its interest in the Yombo field, (iii) the acquisition of us or CMS by another consolidated group or (iv) 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 $35.4 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 $53.1 million. CMS sold their interest in the Yombo field in 2002 to a U.S. subsidiary of Perenco, S.A. (Perenco), which is awaiting approval from the government of Congo. The sale was not a triggering event as both CMS and Perenco filed a request for a Closing Agreement with the Internal Revenue Service in accordance with the U.S. consolidated tax return regulations prior to the sale. Further, we do not expect a triggering event to occur with respect to Nuevo, CMS or Perenco, and do not believe the agreement will have a material adverse effect upon us.

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.

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.

Operating Leases

We have operating leases in the normal course of business, which include those for office space and operating facilities and office and operating equipment, with varying terms from 2002 to 2009. Total rental expense under the agreements was $2.2 million in 2002, $4.1 million in 2001 and $2.7 million in 2000. The rental expense for operating equipment is recorded in lease operating expense and other rental expense is recorded in general and administrative expense. At December 31, 2002, our total commitments under operating leases were approximately $8.9 million.

Minimum annual rental commitments at December 31, 2002, were as follows:

	Operating Leases (In thousands)
2003	$ 1,789
2004	1,833
2005	1,796
2006	1,475
2007	969
Thereafter	1,017
Total	$ 8,879

13. 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 133. Quantities covered by crude hedges are based on West Texas Intermediate ("WTI") barrels. Our production is expected to average 74% of WTI, therefore, each WTI barrel hedges 1.35 barrels of our production.

Derivative Instruments Designated as Cash Flow Hedges

At December 31, 2002, we had entered into the following cash flow hedges:

Crude Oil Hedges

Swaps for Sales	Volume MBbls/day	WTI Price ($Bbl.)
1Q03	15,000	$ 24.40
2Q03	12,000	23.86
3Q03	11,000	23.58
4Q03	9,000	23.42
1Q04	7,000	23.62
2003 (1Q-4Q)	2,500	23.80
2004 (1Q-4Q)	4,500	22.82
2005 (1Q-4Q)	4,500	22.14

Collars		
2003 (1Q-4Q)	10,000	$22.00 - $28.91

Natural Gas Hedges

Swaps for Sales	Volume MMBtu/day	Price (MMBtu)	I
1Q03	6,000	$ 4.76	Waha
2003 (1Q-4Q)	2,000	4.15	W
2004 (1Q-4Q)	3,000	3.91	W
Collars			
2003 (1Q-4Q)	6,000	$ 3.70 - $4.30	W

Natural Gas Hedges

Swaps for Purchases	Volume MMBtu/day	Price (MMBtu)	In
2004 (1Q-4Q)	8,000	$ 3.91	So
2005 (1Q-4Q)	8,000	3.85	So

At December 31, 2002, the fair market value of these hedge positions is a loss of $22.3 million. All of these agreements expose us to counterparty credit risk to the extent that the counterparty is unable to meet its settlement commitments.

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 million to hedge the fair value of our 9 1/2% Notes due 2008 and our 9 3/8% Notes due 2010. These swaps were designated as fair value hedges and were reflected as an increase or decrease of long-term debt with a corresponding increase in 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 of $9.6 million on our 9 3/8% Notes and $0.5 million in accrued interest and the present value of the swap option of $2.5 million on our 9 1/2% Notes. The gain of $9.6 million on our 9 3/8% Notes and $2.5 million on our 9 1/2% Notes is reflected as an increase of long-term debt and will be amortized as a reduction to interest expense over the life of the Notes. As of December 31, 2002, we amortized $0.4 million as a reduction of interest expense.

In late August and early November 2002, we entered into two interest rate swap agreements with notional amounts totaling $50 million each, to hedge a portion of the fair value of our 9 3/8% Notes due 2010. These swaps are designated as fair value hedges and are reflected as an increase of long-term debt of $2.2 million as of December 31, 2002, with a corresponding increase in long-term assets. Under the terms of the first agreement, the counterparty pays us a weighted average fixed annual rate of 9 3/8% on total notional amounts 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%. Under the terms of the second agreement, the counterparty pays us a weighted average fixed annual rate of 9 3/8% on total notional amounts 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 4.95%.

Fair Values of Financial Instruments

Fair value for cash, short-term investments, receivables and payables approximates carrying value. The following table details the carrying values and approximate fair values of our other investments, derivative financial instruments and long-term debt at December 31, 2002 and 2001.

	December 31, 2002		December 31, 2	
	Carrying Amount	Fair Value	Carrying Amount	Fair
	(in thousands)			
Derivative Instruments				
Commodity price swaps	$ (22,311)	$ (22,311)	$ 10,120	$
Interest rate swaps	2,161	2,161	(633)	
Option commodity contracts	--	--	9,490	
Long-term debt (see Note 11)	409,577	415,833	450,444	
TECONS	115,000	64,400	115,000	

The fair value of our long-term debt and TECONS were determined based upon interest rates currently available to us for borrowing with similar terms at December 31, 2002 and 2001.

Other - Enron Exposure and Call Spreads

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. As a result, we recorded a $7.6 million charge in the fourth quarter of 2001: $1.2 million related to the November and December 2001 crude oil price swaps, $0.9 million related to the Enron call spread (see below), and $5.5 million related to the fair value of open hedges of second, third and fourth quarter 2002 crude oil production. 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 hedge items affect earnings. The $2.2 million deferred gain in Other Comprehensive Income at December 31, 2001 was reclassified into earnings in 2002.

In 2001 and 2000, we entered into call spreads with the anticipation of using the proceeds to offset the Unocal Contingent payment. (See Note 14). 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 call spread with Enron was cancelled. (See above discussion). The remaining mirror call spread is not designated as a hedging instrument and is marked-to-market with changes in fair value recognized currently as derivative gain/loss. At December 31, 2002, $2.8 million is reflected in long-term liabilities.

14. CONTINGENT PAYMENT AND PRICE SHARING AGREEMENTS

In connection with the acquisition from Unocal in 1996 of the properties located in California, we are obligated to make a contingent payment for the years 1998 through 2004 if oil prices exceed thresholds set forth in the agreement with Unocal. Contingent payments are accounted for as a purchase price adjustment to oil and gas properties. The contingent payment will equal 50% of the difference between the actual average annual price received on a field-by-field basis (capped by a maximum price) and a minimum price, less ad valorem and production taxes, and certain other permitted deductions, multiplied by the actual number of barrels of oil sold that are produced from the properties acquired from Unocal during the respective year. The minimum price of $17.75 per Bbl under the agreement (determined based on the near month delivery of WTI crude oil on the NYMEX) is escalated at 3% per year and the maximum price of $21.75 per Bbl on the NYMEX is escalated at 3% per year. Minimum and maximum prices are reduced to reflect the field level price by subtracting a fixed differential established for each field. The reduction was established at approximately the differential between actual sales prices and NYMEX prices in effect in 1995 ($4.34 per Bbl weighted average for all the properties acquired from Unocal). We accumulate credits to offset the contingent payment when prices are $0.50 per Bbl or more below the minimum price. On March 15, 2002, we paid $10.8 million to Unocal attributable to calendar year 2001 and recorded the payment in oil and gas properties. In March 2003, we advised Unocal that we had failed to take deductions to the purchase price that we believe are permitted by the agreement. Application of these deductions resulted in no payment due for either calendar year 2001 or 2002 and resulted in a credit being available to use against future obligations. Unocal disputes this position. Discussions are taking place between the companies in an effort to resolve this issue for both years. While the final outcome of this matter is not presently determinable, its resolution is not expected to have a significant impact to our operating results, financial condition or liquidity.

In connection with the acquisition of the Congo properties in 1995, we entered into a price sharing agreement with the seller. Under the terms of the agreement, if the average price received for the oil production during the year is greater than the benchmark price established by the agreement, we are obligated to pay the seller 50% of the difference between the benchmark price and the actual price received, for all the production associated with this acquisition. The benchmark price was $15.96 million in 2002, $15.78 per Bbl for 2001 and $15.19 per Bbl for 2000. The benchmark price increases each year, based on the increase in the Consumer Price Index. For 2002, the effect of this agreement was that we only owned upside above $15.96 per Bbl on approximately 66% of our Congo production. We were obligated to pay the seller $4.1 million in

2002, $3.4 million in 2001 and $5.4 million in 2000 under this price sharing agreement. Because there is no termination date associated with this agreement, it is accounted for as an oil royalty.

We acquired a 12% working interest in the Point Pedernales oil field from Unocal in 1994 and the remainder of its 80.3 % working interest from Torch in 1996. We are entitled to all revenue proceeds up to $9.00 per Bbl, with the excess revenue over $9.00 per Bbl, if any, we share with the original owners from whom Torch acquired its interest. We own amounts below $9.00 per Bbl with the other working interest owners based on their respective ownership interests. For 2002, the effect of this agreement is we were entitled to receive the pricing upside above $9.00 per Bbl on approximately 73% of the gross Point Pedernales production. As of December 31, 2002, we had $0.5 million accrued as our obligation under this agreement. As of December 31, 2001, we had $0.2 million accrued as our obligation under this agreement. As of December 31, 2000, we had $0.6 million accrued as our obligation under this agreement. Obligations under this agreement are accounted for as an oil royalty.

15. SUPPLEMENTAL INFORMATION (UNAUDITED)

Oil and Gas Producing Activities

Included herein is information with respect to oil and gas acquisition, exploration, development and production activities, which is based on estimates of year-end oil and gas reserve quantities and estimates of future development costs and production schedules. Reserve quantities and future production as of December 31, 2002, and for previous years, are based primarily on reserve reports prepared by the independent petroleum engineering firm of Ryder Scott Company. These estimates are inherently imprecise and subject to substantial revision.

Estimates of future net cash flows from proved reserves of gas, oil, condensate and natural gas liquids ("NGL") were made in accordance with SFAS No. 69, Disclosures about Oil and Gas Producing Activities. The estimates are based on the NYMEX cash price at year-end 2002, of $31.20 per Bbl and $4.79 per MMbtu adjusted for basis differences, and are adjusted for the effects of contractual agreements with Unocal and Amoco in connection with the California and Congo property acquisitions (see Note 14).

Estimated future cash inflows are reduced by estimated future development and production costs based on year-end cost levels, assuming continuation of existing economic conditions, and by estimated future income tax expense. Tax expense is calculated by applying the existing statutory tax rates, including any known future changes, to the pre-tax net cash flows, less depreciation of the tax basis of the properties and depletion allowances applicable to the gas, oil, condensate and NGL production. Because the disclosure requirements are standardized, significant changes can occur in these estimates based upon oil and gas prices currently in effect. The results of these disclosures should not be construed to represent the fair market value of our oil and gas properties. A market value determination would include many additional factors including: (i) anticipated future increases or decreases in oil and gas prices and production and development costs; (ii) an allowance for return on investment; (iii) the value of additional reserves, not considered proved at the present, which may be recovered as a result of further exploration and development activities; and (iv) other business risks.

Costs incurred

The following table sets forth the costs incurred in property acquisition and development activities:

	Year Ended December 31,		
	2002	2001	2000
		(In thousands)	
Domestic			
Property acquisition			
Proved properties	$ 96,747	$ 41,135	$ --
Unproved properties (1)	10,317	6,131	4,892
Exploration	357	16,004	5,591
Development			
Proved reserves	39,594	95,005	79,857
Unproved reserves	12,937	5,716	11,433
	$ 159,952	$ 163,991	$ 101,773
Foreign			
Property acquisition			
Proved properties	$ --	$ --	$ --
Unproved properties (1)	--	47	479
Exploration	1,244	4,703	6,467
Development			
Proved reserves	1,527	20,222	4,406
Unproved reserves	--	--	342
	$ 2,771	$ 24,972	$ 11,694
Total			
Property acquisition			
Proved properties	$ 96,747	$ 41,135	$ --
Unproved properties (1)	10,317	6,178	5,371
Exploration	1,601	20,707	12,058
Development			
Proved reserves	41,121	115,227	84,263
Unproved reserves	12,937	5,716	11,775
	$ 162,723	$ 188,963	$ 113,467

(1) Includes capitalized interest directly related to development activities of $1.9 million in 2002 and $2.5 million in 2001. There was no capitalized interest in 2000.

Capitalized costs

The following table sets forth the capitalized costs relating to oil and gas activities and the associated accumulated depreciation, depletion and amortization:

	As of December 31,		
	2002	2001	
		(In thousands)	
Domestic			
Proved properties	$ 829,839	$ 893,215	$
Unproved properties	28,369	27,117	
Total capitalized costs	858,208	920,332	
Accumulated depreciation, depletion and amortization	(304,740)	(378,644)	
Net capitalized costs	$ 553,468	$ 541,688	$
Foreign			
Proved properties	$ 92,964	$ 91,437	$
Unproved properties	86	2,660	
Total capitalized costs	93,050	94,097	
Accumulated depreciation, depletion and amortization	(44,155)	(37,693)	
Net capitalized costs	$ 48,895	$ 56,404	$
Total			
Proved properties	$ 922,803	$ 984,652	$
Unproved properties	28,455	29,777	
Total capitalized costs	951,258	1,014,429	
Accumulated depreciation, depletion and amortization	(348,895)	(416,337)	
Net capitalized costs	$ 602,363	$ 598,092	$

Results of operations for producing activities

	Year Ended Decem	
	2002	2001
		(In thousan
Domestic		
Revenues from oil and gas producing activities	$ 286,870	$ 291,0
Production costs	(127,270)	(153,1
Exploration costs	(1,024)	(16,1
Depreciation, depletion and amortization	(66,745)	(59,4
Provision for impairment of oil and gas properties	--	(89,4
Income (loss) before income tax	91,831	(27,2
Income tax (provision) benefit	(38,293)	10,9
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 53,538	$ (16,2
Foreign		
Revenues from oil and gas producing activities	$ 32,116	$ 36,0
Production costs	(10,747)	(14,0
Exploration costs	(3,517)	(5,8
Depreciation, depletion and amortization	(6,198)	(10,3
Provision for impairment of oil and gas properties	--	(14,0
Income (loss) before income tax	11,654	(8,3
Income tax (provision) benefit	(4,860)	3,3
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 6,794	$ (4,9
Total		
Revenues from oil and gas producing activities	$ 318,986	$ 327,0
Production costs	(138,017)	(167,2
Exploration costs	(4,541)	(22,0
Depreciation, depletion and amortization	(72,943)	(69,8
Provision for impairment of oil and gas properties	--	(103,4
Income (loss) before income tax	103,485	(35,5
Income tax (provision) benefit	(43,153)	14,2
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 60,332	$ (21,2

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* Results of operations represent results from continuing operations.

Our estimated total proved and proved developed reserves of oil and gas are as follows:

	Year Ended December 31,			
	2002		2001	
	Oil (1) (MBbl)	Gas (MMcf)	Oil (1) (MBbl)	Gas (MMcf)
Domestic				
Proved reserves at beginning of year	199,014	111,363	196,692	165,977
Revisions of previous estimates	18,015	16,213	15,164	(55,422)
Extensions and discoveries	--	2,564	311	578
Production	(14,640)	(13,460)	(14,536)	(12,750)
Sales of reserves in-place	(168)	(4,829)	--	--
Purchase of reserves in-place	4,016	61,993	1,383	12,980
Proved reserves at end of year	206,237	173,844	199,014	111,363
Proved developed reserves				
Beginning of year	169,507	92,890	160,039	122,500
End of year	187,735	139,609	169,507	92,890
Foreign				
Proved reserves at beginning of year	15,844	1,129	23,202	--
Revisions of previous estimates	131	(236)	(5,478)	--
Extensions and discoveries	--	--	--	1,129
Production	(1,875)	(52)	(1,880)	--
Sales of reserves in-place	--	--	--	--
Purchase of reserves in-place	--	--	--	--
Proved reserves at end of year	14,100	841	15,844	1,129
Proved developed reserves				
Beginning of year	15,844	1,129	11,013	--
End of year	14,100	841	15,844	1,129
Total (2)				
Proved reserves at beginning of year	214,858	112,492	219,894	165,977
Revisions of previous estimates	18,146	15,977	9,686	(55,422)
Extensions and discoveries	--	2,564	311	1,707
Production	(16,515)	(13,512)	(16,416)	(12,750)
Sales of reserves in-place	(168)	(4,829)	--	--
Purchase of reserves in-place	4,016	61,993	1,383	12,980
Proved reserves at end of year	220,337	174,685	214,858	112,492
Proved developed reserves				
Beginning of year	185,351	94,019	171,052	122,500
End of year	201,835	140,451	185,351	94,019

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(1) Includes estimated NGL reserves.

(2) Reserves and production from discontinued operations are included in this table.

Discounted future net cash flows

The standardized measure of discounted future net cash flows and changes therein are shown below:

	Year Ended December 31		
	2002	2001	
		(In thousands)	
Domestic			
Future cash inflows	$ 5,290,440	$ 3,182,420	$
Future production costs	(2,435,730)	(1,773,397)	
Future development costs	(392,746)	(382,412)	
Future net inflows before income tax	2,461,964	1,026,611	
Future income taxes	(690,501)	(149,564)	
Future net cash flows	1,771,463	877,047	
10% discount factor	(693,830)	(366,050)	
Standardized measure of discounted future net cash flows	$ 1,077,633	$ 510,997	$
Foreign			
Future cash inflows	$ 343,406	$ 248,569	$
Future production costs	(169,832)	(123,628)	
Future development costs	(4,406)	(6,863)	
Future net inflows before income tax	169,168	118,078	
Future income taxes	(48,777)	(25,237)	
Future net cash flows	120,391	92,841	
10% discount factor	(28,738)	(24,152)	
Standardized measure of discounted future net cash flows	$ 91,653	$ 68,689	$
Total			
Future cash inflows	$ 5,633,846	$ 3,430,989	$
Future production costs	(2,605,562)	(1,897,025)	
Future development costs	(397,152)	(389,275)	
Future net inflows before income tax	2,631,132	1,144,689	
Future income taxes	(739,278)	(174,801)	
Future net cash flows	1,891,854	969,888	
10% discount factor	(722,568)	(390,202)	
Standardized measure of discounted future net cash flows	$ 1,169,286	$ 579,686	$

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

	Year Ended December 3	
	2002	2001
		(In thousands)
Domestic		
Standardized measure -- beginning of year	$ 510,997	$ 1,149,562
Sales, net of production costs	(170,357)	(154,785)
Purchases of reserves in-place	119,143	13,759
Net change in prices and production costs	560,784	(904,288)
Extensions, discoveries and improved recovery, net of future production and development costs	9,149	2,750
Changes in estimated future development costs	29,946	(61,735)
Development costs incurred	31,123	62,562
Revisions of quantity estimates	120,287	20,906
Accretion of discount	51,100	151,060
Net change in income taxes	(312,989)	211,477
Sales of reserves in-place	(5,245)	--
Changes in production rates and other	133,695	19,729
Standardized measure -- end of year	$ 1,077,633	$ 510,997
Foreign		
Standardized measure -- beginning of year	$ 68,689	$ 105,327
Sales, net of production costs	(21,368)	(21,899)
Purchases of reserves in-place	--	--
Net change in prices and production costs	45,408	(56,360)
Extensions, discoveries and improved recovery, net of future production and development costs	--	114
Changes in estimated future development costs	449	16,455
Development costs incurred	1,527	16,100
Revisions of quantity estimates	736	(25,804)
Accretion of discount	7,782	13,861
Net change in income taxes	(20,484)	24,150
Sales reserves in-place	--	--
Changes in production rates and other	8,914	(3,255)
Standardized measure -- end of year	$ 91,653	$ 68,689
Total		
Standardized measure -- beginning of year	$ 579,686	$ 1,254,889
Sales, net of production costs	(191,725)	(176,684)
Purchases of reserves in-place	119,143	13,759
Net change in prices and production costs	606,192	(960,648)
Extensions, discoveries and improved recovery, net of future production and development costs	9,149	2,864
Changes in estimated future development costs	30,395	(45,280)

Development costs incurred	32,650	78,917
Revisions of quantity estimates	121,023	(4,898)
Accretion of discount	58,882	164,921
Net change in income taxes	(333,473)	235,627
Sales of reserves in-place	(5,245)	--
Changes in production rates and other	142,609	16,219
Standardized measure -- end of year	$ 1,169,286	$ 579,686

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16. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

	2002		
	1st Qtr	2nd Qtr	3rd Qtr
	(In thousands, except p		
Revenues	$ 73,268	$ 79,995	$ 87,12
Income (loss) from operations	12,273	36,266	22,02
Income (loss) from continuing operations	586	15,036	4,47
Income (loss) from discontinued operations, net of income tax	876	1,530	1,67
Net Income (loss)	1,462	16,566	6,15
Basic earnings (loss) per share (1)			
Continuing operations	$ 0.04	$ 0.88	$ 0.2
Discontinued operations	0.05	0.09	0.0
Net income (loss)	$ 0.09	$ 0.97	$ 0.3
Diluted earnings (loss) per share (1)			
Continuing operations	$ 0.04	$ 0.87	$ 0.2
Discontinued operations	0.05	0.09	0.1
Net income (loss)	$ 0.09	$ 0.96	$ 0.3

	2001(2)		
	1st Qtr	2nd Qtr	3rd Qtr
	(In thousands, except		

Revenues	$ 98,907	$ 89,039	$ 75,76
Income (loss) from operations	22,299	13,400	5,27
Income (loss) from continuing operations	6,035	904	(4,03
Income (loss) from discontinued operations, net of income tax	3,568	1,755	1,65
Net Income (loss)	9,603	2,659	(2,38
Basic earnings (loss) per share (1)			
Continuing operations	$ 0.36	$ 0.05	$ (0.2
Discontinued operations	0.22	0.11	0.1
Net income (loss)	$ 0.58	$ 0.16	$ (0.1
Diluted earnings (loss) per share (1)			
Continuing operations	$ 0.35	$ 0.05	$ (0.2
Discontinued operations	0.21	0.11	0.1
Net income (loss)	$ 0.56	$ 0.16	$ (0.1

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(1) The sum of the individual quarterly net income (loss) per common share may not agree with year-to-date net income (loss) per common share as each quarterly computation is based on the weighted average number of common shares outstanding during that period.

(2) Results for the 2001 quarters were revised due to a change in accounting for processed fuel oil and natural gas liquids inventories (See Note 2).

(3) Fourth quarter 2001 results include $103.5 million of impairments.

(4) Fourth quarter 2002 results include a $17.8 million after-tax write down of assets held for sale in discontinued operations.

INDEPENDENT AUDITORS' REPORT ON CONSOLIDATED FINANCIAL STATEMENT SCHEDULE

To the Board of Directors and Stockholders
Nuevo Energy Company:

Under date of March 17, 2003, we reported on the consolidated balance sheets of Nuevo Energy Company as of December 31, 2002 and 2001, and the related consolidated statements of income, stockholders' equity, cash flows and comprehensive income for each of the years in the three-year period ended December 31, 2002. In connection with our audits of the aforementioned consolidated financial statements, we also audited the related consolidated financial statement schedule. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statement schedule based on our audits.

In our opinion, the consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

KPMG LLP

Houston, Texas
March 17, 2003

SCHEDULE II

NUEVO ENERGY COMPANY
VALUATION AND QUALIFYING ACCOUNTS

YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000
(IN THOUSANDS)

		Additions		
	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deducti
2002				
Allowance for doubtful accounts	$ 1,280	$ --	$ --	$
Valuation allowance on deferred taxes	1,777	--	--	
Legal reserves	4,807	--	--	3
Environmental reserves	5,092	--	531	
2001				
Allowance for doubtful accounts	766	1,314	--	
Valuation allowance on deferred taxes	1,777	--	--	
Legal reserves	807	4,000	--	
Environmental reserves	4,479	--	613	
2000				
Allowance for doubtful accounts	--	--	766	
Valuation allowance on deferred taxes	1,777	--	--	
Legal reserves	1,951	--	--	1
Environmental reserves	4,500	--	--	

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

A change in independent auditors from Arthur Andersen LLP to KPMG LLP was reported in our Current Report on Form 8-K dated July 22, 2002.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required by this item will be included in our definitive proxy statement, which will be filed not later than 120 days after December 31, 2002, and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be included in our definitive proxy statement, which will be filed not later than 120 days after December 31, 2002, and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by Item 403 of Regulation S-K will be included in our definitive proxy statement, which will be filed not later than 120 days after December 31, 2002, and is incorporated herein by reference.

EQUITY COMPENSATION PLAN INFORMATION

The following table sets forth information about the Common Stock that may be issued under all of the Company's existing equity compensation plans as of December 31, 2002:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights
Equity compensation plans approved by security holders	2,367,482	$ 17.56
Equity compensation plans not approved by security holders	410,452	$ 13.10
Total	2,777,934	$ 16.90

Equity compensation plans approved by our shareholders include the 1990

Option Plan, the 1993 Stock Incentive Plan, and the 1999 Stock Incentive Plan.

The equity compensation plans that have not been approved by our shareholders are the 2001 Stock Incentive Plan, the Janet F. Clark Stock Option Plan and the George B. Nilsen Stock Option Plan.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by this item will be included in a definitive proxy statement, which will be filed not later than 120 days after December 31, 2002, and is incorporated herein by reference.

ITEM 14. 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 annual 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 IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) THE FOLLOWING DOCUMENTS ARE FILED AS PART OF THIS REPORT:

1. Financial Statements.

Our consolidated financial statements are included in Part II, Item 8 of this report:

2. Financial statement schedules and supplementary information required to be submitted.

Schedules other than that listed above are omitted because they are not applicable

(b) REPORTS ON FORM 8-K:

o We filed a current report on Form 8-K on November 15, 2002 filing 2001 re-audited financial statements.

NUEVO ENERGY COMPANY

EXHIBIT LIST
DECEMBER 31, 2002

Each exhibit identified below is filed as a part of this report. Exhibits not incorporated by reference to a prior filing are designated by an asterisk; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14 (c) of Form 10-K.

(2) Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession.

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).

(3) Articles of Incorporation and bylaws.

3.1 Certificate of Incorporation of Nuevo Energy Company (Exhibit 3.1 to our 1999 Second Quarter Form 10-Q).

3.2 Certificate of Amendment to the Certificate of Incorporation of Nuevo Energy Company (Exhibit 3.2 to our 1999 Second Quarter Form 10-Q).

3.3 Bylaws of Nuevo Energy Company (Exhibit 3.3 to our 1999 Second Quarter Form 10-Q).

3.4 Amendment to section 3.1 of the Bylaws of Nuevo Energy Company (Exhibit 3.4 to our 1999 Second Quarter Form 10-Q).

(4) Instruments defining the rights of security holders, including indentures.

4.1 Specimen Stock Certificate (Exhibit 4.1 to our Form S-4 (No. 33-33873) filed under the Securities Act of 1933).

4.2 Indenture dated April 1, 1996 among Nuevo Energy Company as Issuer, various Subsidiaries as the Guarantors, and State Street Bank and Trust Company as the Trustee - 9 1/2% Senior Subordinated Notes due 2006. (Incorporated by reference from Form S-3 (No. 333-1504).

4.3 Form of Amended and Restated Declaration of Trust dated December 23, 1996, among the Company, as Sponsor, Wilmington Trust Company, as Institutional Trustee and Delaware Trustee, and Michael D. Watford, Robert L. Gerry, III and Robert M. King, as Regular Trustees. (Exhibit 4.1 to our Form 8-K filed on December 23, 1996).

4.4 Form of Subordinated Indenture dated as of November 25, 1996, between the Company and Wilmington Trust Company, as Indenture Trustee. (Exhibit 4.2 to Form 8-K filed on December 23, 1996).

4.5 Form of First Supplemental Indenture dated December 23, 1996, between the Company and Wilmington Trust Company, as Indenture Trustee. (Exhibit 4.3 to Form 8-K filed on December 23, 1996).

4.6 Form of Preferred Securities Guarantee Agreement dated as of December 23, 1996, between the Company and Wilmington Trust Company, as Guarantee Trustee. (Exhibit 4.4 to Form 8-K filed on December 23, 1996).

4.7 Form of Certificate representing TECONS. (Exhibit 4.5 to Form 8-K filed on December 23, 1996).

4.8 Shareholder Rights Plan, dated March 5, 1997, between Nuevo Energy Company and American Stock Transfer & Trust Company, as Rights Agent (Exhibit 1 to our Form 8-A filed on April 1, 1997).

4.9 Release and Termination of Subsidiary Guarantees with respect to the 9 1/2% Senior Subordinated Notes due 2006. (Exhibit 4.11 to our 1997 Form 10-K)

4.10 Second Supplemental Indenture to the Indenture dated April 1, 1996, dated August 9, 1999 between Nuevo Energy Company and State Street Bank and Trust Company - 9 1/2% Senior Subordinated Notes due 2006 (Exhibit 4.10 to our Form S-4 (No. 333-90235) filed on November 3, 1999).

4.11 Indenture dated as of August 20, 1999, between Nuevo Energy Company and State Street Bank Trust Company, as Trustee (Exhibit 4.11 to our Form S-4 (No. 333-90235) filed on November 3, 1999).

4.12 Registration Agreement dated August 20, 1999, between Nuevo Energy Company, Banc of America Securities LLC and Salomon Smith Barney Inc. (Exhibit 4.12 to our Form S-4 (No. 333-90235) filed on November 3, 1999).

4.13 Indenture dated September 26, 2000, between Nuevo Energy Company and State Street Bank and Trust Company as the Trustee - 9 3/8% Senior subordinated Notes due 2010 (Exhibit 4.12 to our 2000 Third Quarter Form 10-Q).

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	*99.2	Certification of Chief Financial Officer of Nuevo Energy Company

GLOSSARY OF OIL AND GAS TERMS

TERMS USED TO DESCRIBE QUANTITIES OF OIL AND NATURAL GAS

- Bbl -- One stock tank barrel, or 42 US gallons liquid volume, of crude oil or other liquid hydrocarbons.
- Bcf -- One billion cubic feet of natural gas.
- Bcfe -- One billion cubic feet of natural gas equivalent.
- BOE -- One barrel of oil equivalent, converting gas to oil at the ratio of 6 Mcf of gas to 1 Bbl of oil.
- BOPD -- One barrel of oil per day.
- MBbl -- One thousand Bbls.
- Mcf -- One thousand cubic feet of natural gas.
- MMBbl -- One million Bbls of oil or other liquid hydrocarbons.
- MMcf -- One million cubic feet of natural gas.
- MBOE -- One thousand BOE.
- MMBOE -- One million BOE.

TERMS USED TO DESCRIBE THE COMPANY'S INTERESTS IN WELLS AND ACREAGE

- Gross oil and gas wells or acres -- The Company's gross wells or gross acres represent the total number of wells or acres in which the Company owns a working interest.
- Net oil and gas wells or acres -- Determined by multiplying "gross" oil and natural gas wells or acres by the working interest that the Company owns in such wells or acres represented by the underlying properties.

TERMS USED TO ASSIGN A PRESENT VALUE TO THE COMPANY'S RESERVES

- Standard measure of proved reserves -- The present value, discounted at 10%, of the pre-tax future net cash flows attributable to estimated net proved reserves. The Company calculates this amount by assuming that it will sell the oil and gas production attributable to the proved reserves estimated in its independent engineer's reserve report for the prices it received for the production on the date of the report, unless it had a contractual arrangement specific to a property to sell the production for a different price. The Company also assumes that the cost to produce the reserves will remain constant at the costs prevailing on the date of the report. The assumed costs are subtracted from the assumed revenues resulting in a stream of future net cash flows. Estimated future income taxes using rates in effect on the date of the report are deducted from the net cash flow stream. The after-tax cash flows are discounted at 10% to result in the standardized measure of the Company's proved reserves. The standardized measure of the Company's proved reserves is disclosed in the Company's audited financial statements in Note 15.
- Pre-tax discounted present value -- The discounted present value of proved reserves is identical to the standardized

measure, except that estimated future income taxes are not deducted in calculating future net cash flows. The Company discloses the discounted present value without deducting estimated income taxes to provide what it believes is a better basis for comparison of its reserves to the producers who may have different tax rates.

TERMS USED TO CLASSIFY OUR RESERVE QUANTITIES

- Proved reserves -- The estimated quantities of crude oil, natural gas and natural gas liquids which, upon analysis of geological and engineering data, appear with reasonable certainty to be recoverable in the future from known oil and natural gas reservoirs under existing economic and operating conditions.

The SEC definition of proved oil and gas reserves, per Article 4-10(a)(2) of Regulation S-X, is as follows:

Proved oil and gas reserves. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(a) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(b) Reserves which can be produced economically through application of improved recovery, techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(c) Estimates of proved reserves do not include the following: (1) oil that may become available from known reservoirs, but is classified separately as "indicated additional reserves"; (2) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (3) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (4) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

- Proved developed reserves -- Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

- Proved undeveloped reserves -- Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required.

TERMS WHICH DESCRIBE THE COST TO ACQUIRE THE COMPANY'S RESERVES

- Finding costs -- The Company's finding costs compare the amount the Company spent to acquire, explore and develop its oil and gas properties, explore for oil and gas and to drill and complete wells during a period, with the increases in reserves during the period. This amount is calculated by dividing the net change in the Company's evaluated oil and property costs during a period by the change in proved reserves plus production over the same period. The Company's finding costs as of December 31 of any year represent the average finding costs over the three-year period ending December 31 of that year.

TERMS WHICH DESCRIBE THE PRODUCTIVE LIFE OF A PROPERTY OR GROUP OF PROPERTIES

- Reserve life index -- A measure of the productive life of an oil and gas property or a group of oil and gas properties, expressed in years. Reserve life index for the years ended December 31, 2002, 2001 or 2000 equal the estimated net proved reserves attributable to a property or group of properties divided by production from the property or group of properties for the four fiscal quarters preceding the date as of which the proved reserves were estimated.

TERMS USED TO DESCRIBE THE LEGAL OWNERSHIP OF THE COMPANY'S OIL AND GAS PROPERTIES

- Royalty interest -- A real property interest entitling the owner to receive a specified portion of the gross proceeds of the sale of oil and natural gas production or, if the conveyance creating the interest provides, a specific portion of oil and natural gas produced, without any deduction for the costs to explore for, develop or produce the oil and natural gas. A royalty interest owner has no right to consent to or approve the operation and development of the property, while the owners of the working interests have the exclusive right to exploit the mineral on the land.

- Working interest -- A real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of oil and natural gas production or a percentage of the production, but requiring the owner of the working interest to bear the cost to explore for, develop and produce such oil and natural gas. A working interest owner who owns a portion of the working interest may participate either as operator or by voting his percentage interest to approve or disapprove the appointment of an operator and drilling and other major activities in connection with the development and operation of a property.

- Net revenue interest -- A real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of oil and natural gas production or a percentage of the production, net of royalty interests and costs to explore for, develop and produce such oil and natural gas.

TERMS USED TO DESCRIBE SEISMIC OPERATIONS

- Seismic data -- Oil and gas companies use seismic data as their principal source of information to locate oil and gas deposits, both to aid in exploration for new deposits and to manage or enhance production from known reservoirs. To gather seismic data, an energy source is used to send sound waves into the subsurface strata. These waves are reflected back to the surface by underground formations, where they are detected by geophones which digitize and record the reflected waves. Computers are then used to process the raw data to develop an image of underground formations.

- 2-D seismic data -- 2-D seismic survey data has been the standard acquisition technique used to image geologic formations over a broad area. 2-D seismic data is collected by a single line of energy sources which reflect seismic waves to a single line of geophones. When processed, 2-D seismic data produces an image of a single vertical plane of sub-surface data.

- 3-D seismic -- 3-D seismic data is collected using a grid of energy sources, which are generally spread over several miles. A 3-D survey produces a three dimensional image of the subsurface geology by collecting seismic data along parallel lines and creating a cube of information that can be divided into various planes, thus improving visualization. Consequently, 3-D seismic data is a more reliable indicator of potential oil and natural gas reservoirs in the area evaluated than 2-D seismic data.

THE COMPANY'S MISCELLANEOUS DEFINITIONS

- Infill drilling - Infill drilling is the drilling of an additional well or additional wells in excess of those provided for by a spacing order in order to more adequately drain a reservoir.

- No. 6 fuel oil (Bunker) - No. 6 fuel oil is a heavy residual fuel oil used by ships, industry, and for large-scale heating installations.

- Upstream oil and gas properties - Upstream is a term used in describing operations performed before those at a point of reference. Production is an upstream operation and marketing is a downstream operation when the refinery is used as a point of reference. On a gas pipeline, gathering activities are considered to have ended when gas reaches a central point for delivery into a single line, and facilities used before this point of reference are upstream facilities used in gathering, whereas facilities employed after commingling at the central point and employed to make ultimate delivery of the gas are downstream facilities.

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: March 31, 2003

By: /s/ James L. Payne
James L. Payne
Chairman, President and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report is signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

By: /s/ James L. Payne
James L. Payne
Chairman, President and
Chief Executive Officer
(Principal Executive Officer)

Date: March 31, 2003

By: /s/ Janet F. Clark
Janet F. Clark
Senior Vice President and
Chief Financial Officer
(Principal Financial and
Accounting Officer)

Date: March 31, 2003

By: /s/ Isaac Arnold, Jr.
Isaac Arnold, Jr.
Director

Date: March 31, 2003

By: /s/ Charles M. Elson
Charles M. Elson
Director

Date: March 31, 2003

By: /s/ Robert L Gerry III	Date: March 31, 2003
Robert L. Gerry III Director	
By: /s/ J. Frank Haasbeek	Date: March 31, 2003
J. Frank Haasbeek Director	
By: /s/ James T. Jongebloed	Date: March 31, 2003
James T. Jongebloed Director	
By: /s/ Gary R. Petersen	Date: March 31, 2003
Gary R. Petersen Director	
By: /s/ Sheryl K. Pressler	Date: March 31, 2003
Sheryl K. Pressler Director	

INDEX TO EXHIBITS

EXHIBIT NUMBER		DESCRIPTION
(2)	Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession.	
	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).
(3)	Articles of Incorporation and bylaws.	
	3.1	Certificate of Incorporation of Nuevo Energy Company (Exhibit 3.1 to our 1999 Second Quarter Form 10-Q).
	3.2	Certificate of Amendment to the Certificate of

Incorporation of Nuevo Energy Company (Exhibit 3.2 to our 1999 Second Quarter Form 10-Q).

3.3 Bylaws of Nuevo Energy Company (Exhibit 3.3 to our 1999 Second Quarter Form 10-Q).

3.4 Amendment to section 3.1 of the Bylaws of Nuevo Energy Company (Exhibit 3.4 to our 1999 Second Quarter Form 10-Q).

(4) Instruments defining the rights of security holders, including indentures.

4.1 Specimen Stock Certificate (Exhibit 4.1 to our Form S-4 (No. 33-33873) filed under the Securities Act of 1933).

4.2 Indenture dated April 1, 1996 among Nuevo Energy Company as Issuer, various Subsidiaries as the Guarantors, and State Street Bank and Trust Company as the Trustee - 9 1/2% Senior Subordinated Notes due 2006. (Incorporated by reference from Form S-3 (No. 333-1504).

4.3 Form of Amended and Restated Declaration of Trust dated December 23, 1996, among the Company, as Sponsor, Wilmington Trust Company, as Institutional Trustee and Delaware Trustee, and Michael D. Watford, Robert L. Gerry, III and Robert M. King, as Regular Trustees. (Exhibit 4.1 to our Form 8-K filed on December 23, 1996).

4.4 Form of Subordinated Indenture dated as of November 25, 1996, between the Company and Wilmington Trust Company, as Indenture Trustee. (Exhibit 4.2 to Form 8-K filed on December 23, 1996).

4.5 Form of First Supplemental Indenture dated December 23, 1996, between the Company and Wilmington Trust Company, as Indenture Trustee. (Exhibit 4.3 to Form 8-K filed on December 23, 1996).

4.6 Form of Preferred Securities Guarantee Agreement dated as of December 23, 1996, between the Company and Wilmington Trust Company, as Guarantee Trustee. (Exhibit 4.4 to Form 8-K filed on December 23, 1996).

4.7 Form of Certificate representing TECONS. (Exhibit 4.5 to Form 8-K filed on December 23, 1996).

4.8 Shareholder Rights Plan, dated March 5, 1997, between Nuevo Energy Company and American Stock Transfer & Trust Company, as Rights Agent (Exhibit 1 to our Form

8-A filed on April 1, 1997).

4.9 Release and Termination of Subsidiary Guarantees with respect to the 9 1/2% Senior Subordinated Notes due 2006. (Exhibit 4.11 to our 1997 Form 10-K)

4.10 Second Supplemental Indenture to the Indenture dated April 1, 1996, dated August 9, 1999 between Nuevo Energy Company and State Street Bank and Trust Company - 9 1/2% Senior Subordinated Notes due 2006 (Exhibit 4.10 to our Form S-4 (No. 333-90235) filed on November 3, 1999).

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+ Management contract or compensatory plan or arrangement required to be filed.

* Not incorporated by reference.