NUEVO ENERGY CO
Form 10-K405
March 29, 2001

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, 2000

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 registered
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. [X]

The aggregate market value of the voting stock held by non-affiliates of the registrant at March 22, 2001, was approximately $291,326,805.

As of March 22, 2001, the number of outstanding shares of the registrant's common stock was 16,505,768.

Documents Incorporated by Reference:

Portions of the registrant's annual proxy statement, to be filed within 120 days after December 31, 2000, are incorporated by reference into Part III.

NUEVO ENERGY COMPANY

ANNUAL REPORT ON FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2000

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NUEVO ENERGY COMPANY

PART I

This document includes "forward looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), Section 21E of the Securities Exchange Act of 1934 ("Exchange Act") 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 under "Management's Discussion and Analysis of Financial Condition and Results of Operations" regarding the Company's financial position, estimated quantities and net present values of reserves, business strategy, plans and objectives of management of the Company for future operations and covenant compliance, are forward looking statements. The Company 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 the Company's expectations ("Cautionary Statements") are set forth throughout this document. All subsequent written and oral forward looking statements attributable to the Company or persons acting on its behalf are expressly qualified by the Cautionary Statements.

Item 1. Business

General

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 Predecessor Partnerships. Such Plan of Consolidation provided for the exchange of the net assets of the Predecessor Partnerships for common stock of Nuevo ("Common Stock"). The Common Stock began trading on the New York Stock Exchange on July 10, 1990, under the symbol "NEV." All references to the "Company" include Nuevo and its majority and wholly-owned subsidiaries, unless otherwise indicated or the context indicates otherwise.

Nuevo, headquartered in Houston, Texas, is primarily engaged in the exploration for, and the acquisition, exploitation, development and production of crude oil and natural gas. The Company's strategy to differentiate itself from its numerous peer group competitors and to generate long term shareholder value consists of: (i) a management philosophy that frames all important decisions in terms of anticipated impact on per share (rather than absolute) growth of reserves, production, cash flow and net asset value; (ii) a contrarian investment and financing orientation, in which the Company seeks to purchase assets during periods of industry weakness and sell assets during periods of industry strength; (iii) the outsourcing of non-strategic functions; and (iv) the alignment of employee compensation structures with shareholder objectives. Nuevo is also committed to an exemplary corporate governance structure, which reinforces management's overarching view that Nuevo should be a conduit for shareholders to achieve superior long-term capital gains. All of Nuevo's directors, other than the chief executive officer, are independent directors. Nuevo's directors and executive officers each have made substantial equity investments in Nuevo, in order to align their interests with that of the Company's stockholders.

The Company accumulates oil and gas reserves through the drilling of exploratory wells on acreage owned by or leased to the Company, or through the purchase of reserves from others. The Company maximizes production from these reserves through the drilling of developmental wells and through other exploitative techniques. The Company also owns and operates gas plants and other facilities, which are ancillary to the primary business of producing oil and natural gas. The Company also owns certain surface real estate parcels in

California that are candidates for sale and/or development in future years.

Oil and Gas Activities

Since its inception in 1990, Nuevo has expanded its operations through a series of disciplined, low-cost acquisitions of oil and gas properties and the subsequent exploitation and development of these properties. The Company has complemented these efforts with divestitures of non-core assets and an opportunistic exploration program, which provides exposure to high potential prospects. The Company's primary strengths are its large inventory of exploitation projects in its core areas of operation which the Company believes will support future growth in reserves and production per share; its ability to identify and acquire, at attractive prices, long-lived

producing properties which have significant potential for further exploration, exploitation and development; a capital structure supportive of a growing investment program and future acquisitions; and a price risk management policy designed to protect the Company's ability to generate self-sustaining cash flow and to meet the interest coverage tests under the Company's bond indentures. During the five years ended December 31, 2000, the Company invested $594.7 million in six acquisitions that added estimated net proved reserves of 196.6 MMBBLS of oil and 171.1 BCF of natural gas and replaced 329% of its production at an average cost of $3.32 per BOE.

Domestic Operations

As of December 31, 2000, the Company's estimated net U.S. proved reserves totaled 224.4 MMBOE or 91% of Nuevo's total proved reserve base. During 2000, the Company's domestic production was 18.1 MMBOE, or 91% of total production.

The majority of the Company's domestic properties are located in the state of California, where the Company operates from an office in Bakersfield. The Company's properties in California are categorized as either Onshore or Offshore.

Nuevo's California onshore district operations encompass an estimated net proved reserve base of 143.4 MMBOE as of December 31, 2000, and produced 11.0 MMBOE in 2000. The Company's main California onshore properties include the Company's interests in the Cymric, Midway-Sunset and Belridge oil fields in the Western San Joaquin Basin in Kern County, California, the Buena Vista Hills field in the Southern San Joaquin Basin in Kern County and the Coalinga gas field in the North San Joaquin Valley. Certain of the Company's onshore properties utilize thermal operations to maximize current production and the ultimate recovery of reserves. The Company owns a 100% working interest (88% net revenue) in its properties in the Cymric field and the entire working interest and an average net revenue interest of approximately 98% in its 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. The productive zones of the Belridge field above 2,000 feet in which the Company owns royalty interest are operated by another independent energy company. The remaining deeper zones of the Belridge field are operated and owned by the Company in fee with 100% working and net revenue interests. The Company operates and owns a 100% working interest (79% net revenue) in the Buena Vista Hills field. Production from this field is from the Etchegoin Sands and the Antelope Shale. The Coalinga gas field is operated by Nuevo and the

Company owns an average 61% working interest (52% net revenue). Production is from the Gatchell formation. The Company also operates three fee properties in the Brea Olinda oil field in northern Orange County with a 100% working and net revenue interest. The Company has royalty interests in additional wells in the Brea Olinda field. Brea Olinda production is from multiple-pay zones in the Miocene and Pliocene sandstones at depths up to 6,500 feet.

Nuevo's California offshore district operations encompass an estimated net proved reserve base of 79.1 MMBOE as of December 31, 2000, and resulted in production of 6.4 MMBOE in 2000. Nuevo's offshore district properties include the Company's interests in the Point Pedernales, Dos and East Dos Cuadras, Huntington Beach, Santa Clara and Belmont oil fields in federal OCS leases, offshore Santa Barbara and Ventura Counties and Long Beach. The Company acquired a 12% working interest (10% net revenue) in the Point Pedernales field in July 1994 and an additional 68% working interest (57% net revenue) in the field as part of the acquisition of the California properties in 1996. The Point Pedernales field is operated by the Company, and 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. The Company operates three platforms with a 50% working interest (42% net revenue) and another platform with a 67.5% working interest (56% net revenue).

The Company also has properties located in the onshore Gulf Coast region, which are operated from the Company's headquarters in Houston. Nuevo's Houston district operations encompass an estimated net proved reserve base of 1.8 MMBOE as of December 31, 2000, and produced 0.7 MMBOE in 2000. Houston district properties include the Company's interests in the Giddings field in Grimes and Austin Counties, Texas; and in the North Frisco City field in Monroe County, Alabama. The Company owns an interest in 12 producing wells in the

Giddings field and has an average 46.9% working (35.2% net revenue) interest in these wells. The North Frisco City field is operated by Nuevo. Nuevo owns approximately a 22% working (17% net revenue) interest in this field.

The Company continues to create value through domestic oil and gas development projects. The Company initiates workovers, recompletions, development drilling, secondary and tertiary recovery operations and other production enhancement techniques to maximize current production and the ultimate recovery of reserves. The Company has identified in excess of 1,200 domestic exploitation projects on existing properties, at a West Texas Intermediate ("WTI") crude price of $24.86 per Bbl. Capital expenditures for domestic exploitation projects totaled $91.3 million in 2000 and are currently budgeted at approximately $105.0 million in 2001. Examples of current or planned projects include the continuation of horizontal drilling in the onshore district and infill drilling in the Cymric field to further exploit the Diatomite formation.

The Company also has a program targeting exploration opportunities in California. The Company seeks to reduce the risks normally associated with exploration through the use of advanced technologies, such as 3-D seismic surveys and computer aided exploration ("CAEX") techniques, and by participating with experienced industry partners. The Company's exploration program resulted in 11 successful wells and two dry wells in 2000.

Capital expenditures for domestic exploration activity totaled $5.3 million in 2000 and are budgeted at approximately $15.0 million in 2001.

International Operations

As of December 31, 2000, the Company's estimated international net proved reserves totaled 23.2 MMBOE, or 9% of Nuevo's total proved reserve base. During 2000, the Company's international production was 1.8 MMBOE, or 9% of Nuevo's total production.

Congo: The Company's international reserves and production consist of a 50% working interest (37.5% average net revenue) in the Yombo and Masseko oil fields located in the Marine 1 Permit offshore the Republic of Congo in West Africa ("Congo"). Estimated net proved reserves of the Yombo and Masseko oil fields as of December 31, 2000 were 23.2 MMBbl, and production during 2000 totaled 1.8 MMBbl, all from the Yombo field. In 2000, revenues relating to production from the Yombo field accounted for approximately 12% of the total oil and gas revenues for the Company. The properties are located 27 miles offshore in approximately 370 feet of water. The Company also owns 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"). The Company's production is converted on the FPSO to No. 6 fuel oil with less than 0.3% sulfur content.

The Company's most significant international discovery in 1997 was the Masseko M-4 well drilled on the Marine 1 Permit approximately six miles to the northwest of the Yombo field. The Company drilled an exploration well to evaluate the Lower Sendji and sub-salt sections underlying the Masseko structure, as well as to further delineate the Upper Sendji and Tchala zones, which were discovered but not developed by a previous operator. This well tested at rates over 3,000 gross barrels per day from a newly discovered middle Sendji section. Platform design and development plans are being formulated for Masseko. Other potential exploration features are being evaluated for possible future drilling. Additionally, the Company initiated a waterflood project in the Yombo field to enhance production from existing Upper Sendji and Tchala zones. Plans for 2001 include the continuation of horizontal drilling and the waterflood project, as well as facility upgrades and pipeline replacements.

Ghana: In October 1997, Nuevo Ghana, Inc., ("Nuevo Ghana"), signed a petroleum agreement with the Republic of Ghana in West Africa ("Ghana") and the Ghana National Petroleum Corporation, ("GNPC") for petroleum rights covering 2.7 million acres offshore Ghana in the Accra-Keta prospect area. In November 2000, the Company relinquished rights covering 800,000 acres under this agreement, leaving rights covering 1.9 million acres. The Company is the operator of this prospect and has a 50% participating interest. The exploration program for this acreage has involved reprocessing existing seismic data, shooting additional seismic and drilling an exploration well during the first phase of the agreement.

On February 16, 2000, the Company completed its acquisition and processing of a 3-D seismic survey across the eastern portion of its Accra-Keta concession. The Company's costs of the 3-D seismic survey acquisition and processing were approximately $2.0 million. This survey extends from the outer shelf, across the slope, and into the deepwater regions of the block. In October 2000, the Company transferred a 25% participating interest in this permit to a large U.S.-based independent oil and gas company. In January 2001, the Company added two new partners, The Korean National Oil Corporation and SK Corporation, which combined to acquire a 25% interest in the permit on a promoted basis. The addition of these two new partners is subject to Ghanaian government approval. Nuevo will continue to be the operator of the permit and will retain a 50% participating interest. During January and February 2001, Nuevo drilled the NAK #1 exploratory well in the Accra-Keta Permit. This well was located in approximately 1,000 feet of water and was drilled to a total depth of 10,100 feet. The Company plugged and abandoned the NAK #1 well as a dry hole. Costs to drill this well are expected to be approximately $12.5 million (approximately $1.5 million net to Nuevo), and are expected to be incurred in the first quarter of 2001. The Company plans to evaluate the NAK #1 well results during the second quarter of 2001 in order to determine its future exploration plans in this permit.

In February 2000, the Company relinquished its concession for petroleum rights covering approximately 1.7 million acres in the East Cape Three Points concession offshore Ghana. In September 1998, the Company plugged and abandoned its first well in Ghana on the East Cape Three Points concession due to the lack of commercial quantities of hydrocarbons. Dry hole costs and geological and geophysical costs for this well (net to the Company) were $7.3 million and $1.6 million, respectively, in 1998.

Tunisia: In June 2000, the Company acquired interests in two exploration permits in the Republic of Tunisia, North Africa, that added 1.3 million acres to the Company's international portfolio. The first of these permits is the 171,000-acre (gross) Alyane Permit located offshore Tunisia in the Gulf of Gabes. The Company will own a 100% participating interest and act as operator of the block. The Convention and Joint Venture Agreement for the Alyane Permit call for an initial term of four years, followed by two optional three-year terms. Nuevo's work commitment requires shooting 3-D seismic and drilling one exploratory well on the Alyane Permit in the initial term. The Company's anticipated costs under this commitment are approximately $9.0 million. The Company plans to explore the Alyane Permit aggressively and will acquire 3-D seismic data in 2002 with the aim of drilling its first exploratory well in 2002. Nuevo anticipates formal government approval of the Convention and Joint Venture Agreement in the second quarter of 2001.

Effective April 1, 2000, Nuevo acquired a 10.42% participating interest from Bligh Tunisia Inc. in the 1.1-million-acre (gross) Anaguid Permit located onshore southern Tunisia in the Ghadames Basin for approximately $1.5 million. This permit is operated by Anadarko Petroleum Company. Under the current work commitment, the partners must drill one exploration well on the Anaguid Permit by December 2001. The Company's anticipated costs under this commitment are approximately $1.3 million. In addition, the partners plan to reprocess all existing seismic data and acquire new 2-D seismic data during 2001. Following the expiration of the current work commitment term in December 2001, the final renewal phase requires the drilling of one exploration well on the Anaguid Permit during the 2 1/2-year term. Nuevo received government approval of this acquisition in December 2000. The Company and its partners plan to drill a well in the Anaguid Permit in late 2001, subject to rig availability.

In addition to acquiring its interests in the Anaguid and Alyane Permits, Nuevo has, effective April 1, 2000, increased its existing 17.5% participating interest in the 900,000-acre (gross) Fejaj Permit onshore Tunisia, North Africa, by acquiring an additional 20% participating interest from Bligh Tunisia Inc. Nuevo and its partners plan to re-enter and deepen the Chott Fejaj #3 well on the Fejaj Permit to test a sub-salt prospect in 2001. The Company's anticipated costs under this commitment are approximately $750,000. The current term of the Fejaj Permit has been extended to April 2002. The Chott Fejaj #3 well was drilled initially to the top of salt in December 1998, when it was temporarily abandoned. Based on the Company's evaluation of the initial test results on this well, the Company expensed $1.8 million of costs incurred as dry hole costs in 1998.

Canada: In May 2000, the Company acquired a 50% working interest (49.5% net revenue) in 22,140 acres in Alberta, Canada. This project, Marten Hills, is a heavy oil play that will require thermal operations in order to produce. Total costs to acquire this interest were approximately $350,000. No significant operating activity has occurred on this undeveloped acreage to date.

General: Capital expenditures for 2000 international exploration and development activity totaled $3.6 million and $4.7 million, respectively. The Company's 2001 international exploration budget of approximately $9.0 million includes the acquisition and processing of seismic data and the drilling of three to four wells. International development plans for 2001 include the continuation of the Company's waterflood program, facility upgrades and pipeline replacements in the Congo and are currently budgeted at approximately $18.0 million.

The Company's 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 its foreign operations, the Company 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. The Company attempts to conduct its business and financial affairs so as to protect against political and economic risks applicable to operations in the various countries where it operates, but there can be no assurance that the Company will be successful in so protecting itself. A portion of the Company's investment in the Congo is insured through political risk insurance provided by the Overseas Private Investment Corporation ("OPIC"). See "Risk Factors".

Gas Plant and Other Facilities

The Company has owned and operated gas plants and other facilities, most of which have been ancillary to the primary business of producing oil and natural gas.

As of December 31, 2000, the Company owned two gas plants in California that are strategic assets for the Company's oil and gas activities in California. The Stearns Gas Plant is located in the Brea Olinda field and was processing 3.1 MMCFD at December 31, 2000. The HS&P Gas Plant is used to process gas production from the Point Pedernales field. At December 31, 2000, the HS&P Gas Plant was processing 1.3 MMCFD.

In December 1999, the Company sold the Santa Clara Valley Gas Plant, which is located east of Ventura, California, in connection with the Company's sale of its interest in the non-core properties onshore California.

In addition to the gas plants that process Company production, Nuevo has owned certain non-core gas gathering, pipeline and storage assets. In December 1997, the Company announced its intention to dispose of these non-core assets during 1998. The decision was made to dispose of these assets as they did not directly contribute to the Company's core oil and gas operations. Such assets included: the Company's 48.5% interest in the Richfield Gas Storage facility, which was sold in February 1998 for proceeds of $2.1 million, an 80% interest in Bright Star Gathering, Inc., which was sold in July 1998 for proceeds of $1.7 million, and the Illini pipeline, which was sold in November 1999 for proceeds of $10.0 million. An agreement to sell the Illini Pipeline was reached in April 1998; however, the approval of the sale was not received from the Illinois Commerce

Commission until November 1999. No gains or losses were recognized in connection with these sales. The Company recorded a non-cash, pre-tax charge to fourth quarter 1997 earnings of $23.9 million, reflecting the estimated loss on the disposition of these assets. A positive revision to this charge was made in the fourth quarter of 1998 in the amount of $3.7 million to reflect the estimated current fair value of the Illini pipeline. The Company's results of operations included the operating results from these assets through the disposition date, as applicable. Such amounts were not significant relative to total revenues and net operating results for the Company. These assets were not depreciated subsequent to 1997.

On May 2, 1997, the Company sold its 95% interest in the NuStar Joint Venture, which owned an interest in the Benedum natural gas processing plant, and an interest in certain related assets and natural gas gathering systems located in West Texas. The Company recognized a $2.3 million gain on this sale, which was effective January 1, 1997.

Real Estate

In April 1996, along with its acquisition of certain California upstream oil and gas properties from Union Oil Company of California ("Unocal") (see "Acquisitions and Divestitures of Oil and Gas Properties"), the Company

acquired tracts of land in Orange and Santa Barbara Counties in California, two office buildings, one in Ventura County and one in Santa Barbara County, and nearly 8,000 acres of agricultural property in the central valley of California. As of December 31, 2000, there was $53.2 million of basis allocated to land. The office buildings are included in other facilities at December 31, 2000.

Consistent with Nuevo's proactive asset management strategy, the Company may, from time to time, sell certain of its surface real estate assets. The Company expects to monetize a portion of its California real estate portfolio in late 2001 or 2002. In 2000, the Company withdrew its entitlement application for the Brea Highlands residential development from the City of Brea and submitted the project, now named "Tonner Hills", to Orange County, which also has jurisdiction over real estate development.

The agricultural land, primarily in Kings County, Fresno County and Kern County, has surface leases for grazing or farming use, which are compatible with the production of oil.

Acquisitions and Divestitures of Oil and Gas Properties

Consistent with its contrarian acquisition and divestiture strategy, Nuevo has, from time to time, been an active participant in the market for oil and gas properties. The Company attempts to purchase high growth assets which, for any of a variety of reasons, are out of favor in the marketplace and hence available for acquisition at attractive prices. From time to time, the Company also seeks to divest itself of lower growth assets at times when those assets are valued highly by the marketplace. Examples of this contrarian strategy are listed below:

In May 2000, the Company sold its working interest in the Las Cienegas field in California for proceeds of approximately $4.6 million. The Company reclassified these assets to assets held for sale during the third quarter of 1999, at which time it discontinued depleting and depreciating these assets. No impairment charge was recorded upon reclassification to assets held for sale.

On December 31, 1999, the Company completed the sale of its interests in 13 onshore fields and a gas processing plant located in Ventura County, California for an adjusted sales price of $29.6 million. The effective date of the sale was September 1, 1999. A portion of the proceeds, $4.5 million, was deposited in escrow to address possible remediation issues. The funds will remain in escrow until the Los Angeles Regional Water Quality Control Board approves completion of the remediation work. All or any portion of the funds not used in remediation shall be delivered to the Company. The remainder of the proceeds from the sale were used to repay a portion of the Company's outstanding bank debt.

In June 1999, the Company acquired oil and gas properties located onshore and offshore California for $61.4 million from Texaco Inc ("Texaco"). To purchase these assets, the Company used funds from a $100.0 million interest-bearing escrow account that provided "like-kind exchange" tax treatment for the purchase of domestic oil and gas producing properties. The escrow account was created with proceeds from the Company's January 1999 sale of its East Texas natural gas assets. Following the Texaco transaction, the $41.0 million remaining in the escrow account, which included $2.4 million of interest income, was used to repay a portion of outstanding bank debt in early July 1999. The acquired properties had estimated net proved reserves at June 30, 1999, of 33.7 MMBOE and represent either additional interests in the Company's existing properties or are located near its existing properties. The acquisition included interests in Cymric, East Coalinga, Dos Cuadras, Buena Vista Hills and other fields the Company operates.

On January 6, 1999, the Company completed the sale of its East Texas natural gas assets to an affiliate of Samson Resources Company for an adjusted sales price of approximately $191.0 million (see Note 4 to the Notes to Consolidated Financial Statements). The Company realized an $80.2 million adjusted pre-tax gain on the sale of these assets. A $5.2 million gain on settled hedge transactions was also realized in connection with the closing of this sale in 1999. The effective date of the sale was July 1, 1998. The Company reclassified these assets to assets held for sale and discontinued depleting these assets during the third quarter of 1998. Estimated net proved reserves associated with these properties totaled approximately 329.0 BCF of natural gas equivalent at January 1, 1999.

In April 1998, the Company acquired an additional working interest in the Marine 1 Permit in the Congo for $7.8 million. This acquisition increased the Company's net working interest in the Congo from 43.75% to 50.0%.

In July 1996, the Company completed the acquisition of certain East Texas oil and gas properties, which added 31.2 BCF to the Company's reserve base, for a net purchase price of $9.3 million in cash. The package consisted of interests in 11 fields. In December 1996, the holders of the preferential rights on these properties exercised such rights for a cash payment of $8.0 million, acquiring properties constituting approximately half of the estimated proved reserves related to this acquisition.

In June 1996, the Company sold 177 producing wells and the majority of its acreage in the Giddings field and East Texas Austin Chalk holdings for $27.3 million, representing estimated net proved reserves of 4.2 MMBOE as of December 31, 1995. The Company retained ownership of seven wells and surrounding acreage in the Turkey Creek prospect area of the Austin Chalk trend located in Grimes County, Texas.

In April 1996, the Company acquired certain upstream oil and gas properties located onshore and offshore California ("Unocal Properties") from Unocal and certain California oil properties ("Point Pedernales Properties" and, together with the Unocal Properties, the "California Properties") from Torch Energy Advisors Incorporated and certain of its wholly-owned subsidiaries ("Torch") for a combined net purchase price of $525.9 million, plus a contingent payment based on future realized oil prices.

Subsidiaries

The Company's domestic oil and gas operations are organized under Nuevo Energy Company. The Company's oil and gas operations in the Congo are organized under The Nuevo Congo Company and Nuevo Congo Ltd., both wholly-owned subsidiaries of Nuevo. From time to time, the Company may set up a new wholly-owned subsidiary for its international oil and gas operations. As of December 31, 2000, the Company did not have any significant operating activities under any other subsidiary.

Industry Segment Information

For industry segment data (including foreign operations), see Note 10 to the Notes to Consolidated Financial Statements.

Markets

The markets for hydrocarbons continue to be quite volatile. The Company's financial condition, operating results, future growth and the carrying value of its oil and gas properties are substantially dependent on prevailing prices of oil and gas. The Company's ability to maintain or increase its 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 the control of the Company. 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 ("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. Any substantial and extended decline in the price of oil or gas would have an adverse effect on the Company's carrying value of its proved reserves, borrowing capacity, the Company's ability to obtain additional capital, and its revenues, profitability and cash flows from operations. (See Note 14 to the Notes to Consolidated Financial Statements.)

The price of natural gas and the threat of electrical disruptions are factors that create volatility in the Company's California oil and gas operations. Because of the recent developments in these commodities, Nuevo has made significant changes in its natural gas disposition and electricity production in California. Regarding natural gas, Nuevo has a net long position in California - producing more natural gas than consumed in thermal crude production. Moreover, as gas prices escalated in late 2000, Nuevo began to exploit this gas position by diverting gas

consumed in uneconomic cyclic steaming operations to gas sales. In January and February 2001, Nuevo sold an average of 19 MMcfd, or 44% of its total daily gas production, which resulted in an increase in gas sales of 33%. This strategy will remain as long as gas prices support sales over thermal oil production.

In California, Nuevo generates a total of 22.5 Megawatts ("MW") of power at various sites. Two turbines came on-line at the Company's Brea Olinda field using gas previously flared. Three turbines in Kern County produce 12 MW of power and cogenerate 15% of Nuevo's total steam needs in thermal operation. By self-generating power consumption in Kern County, Nuevo has reduced it exposure to rising electricity prices. With the exception of the Point Pedernales field, for which the Company has contracted for firm electric power service, Nuevo's facilities receive power under interruptible service contracts. Considering the fact that California is short of electricity and some Nuevo facilities receive interruptible service, the Company could experience periodic power interruptions. In addition, the State of California could change existing rules or impose new rules or regulations with respect to power that could impact the Company's 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 51% of the Company's total 2000 crude output.

In addition, properties which produce primarily other grades of relatively heavy oil (generally, 20o API or heavier, but produced through non-thermal operations) constituted 32% of the Company's total 2000 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.

In February 2000, the Company entered into a 15-year contract, effective January 1, 2000, to sell all of its current and future California crude oil production to Tosco Corporation. The contract provides pricing based on a fixed percentage of the NYMEX crude oil price for each type of crude oil that Nuevo produces in California. While the contract does not reduce the Company's exposure to price volatility, it does effectively eliminate the basis differential risk between the NYMEX price and the field price of the Company's California oil production. In doing so, the contract makes it substantially easier for the Company to hedge its realized prices. The Tosco contract permits the Company, under certain circumstances, to separately market up to ten percent of its California crude production. The Company exercised this right and, effective January 1, 2001, began selling 5,000 BOPD of its San Joaquin Valley oil production to a third party under a one-year contract containing NYMEX pricing.

The Company's Yombo Field production in its Marine 1 Permit offshore the 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 9% of the Company's total 2000 output. 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 Tosco Corporation accounted for 84%, 79% and 60% of 2000, 1999 and 1998 oil and gas revenues, respectively. Sales to Torch Energy Marketing accounted for 11%, 12% and 10% of 2000, 1999 and 1998 oil and gas revenues, respectively. The loss of any single significant customer or contract could have a material adverse short-term effect on the Company; however, management of the Company does not believe that the loss of any single significant customer or contract would materially affect its 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 the Company's 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 the Company may conduct operations. State and Federal regulations generally are intended to prevent waste of oil and gas, protect rights to produce oil and gas between owners in a common reservoir, control the amount of oil and gas produced by assigning allowable rates of production and control contamination of the environment. Pipelines and gas plants also are subject to the jurisdiction of various Federal, state and local agencies.

The Company's 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, as well as under Section 311 of the Natural Gas Policy Act. 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.

The Company's 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. In this connection, 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 or across 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 the Company conducts 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.

The Company's 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 Company operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect the Company's 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 the Company generally sells its production to third parties and therefore pays royalties on production from federal leases, it is not anticipated that this final rule will have any substantial impact on the Company.

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. The Company owns interest in numerous federal onshore oil and gas leases. It is possible that holders of equity interests in the Company may be citizens of foreign countries, which at some time in the future might be determined to be non-reciprocal under the Mineral Act.

The Company's pipelines used to gather and transport its 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 the Company 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. The Company believes its pipelines are in substantial compliance with all HLPSA and the Pipeline Safety Act. Nonetheless, significant expenses would be incurred if new or additional safety measures are required.

Environmental Regulation

General. The Company's activities are subject to existing Federal, state and local laws and regulations governing environmental quality and pollution control. 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 the operations, capital expenditures, earnings or the competitive position of the Company.

Activities of the Company 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"), the DOT and the FERC. 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.

With respect to the Company's offshore oil and gas operations in California, the Company has significant exit cost liabilities. These liabilities include costs for dismantlement, rehabilitation and abandonment. As of December 31, 2000, the Company's net liability for these exit costs was approximately $82.1 million. The Company is not indemnified for any part of these exit costs.

Waste Disposal. The Company currently owns or leases, and has in the past owned or leased, numerous properties that have been used for production of oil and gas for many years. Although the Company has 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 owned or leased by the Company. In addition, many of these properties have been operated by third parties over whom the Company 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 more strict. Under these new laws, the Company could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination) or to perform remedial plugging operations to prevent future contamination.

The Company may generate wastes, including hazardous wastes that are subject to the Federal Resource Conservation and Recovery Act and comparable state statutes. The EPA has limited the disposal options for certain hazardous wastes and is considering the adoption of stricter disposal standards for nonhazadous wastes. Furthermore, certain wastes generated by the Company's 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, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release of a "hazardous substance" into the environment. These persons include the current owner and operator of a facility and persons that disposed of or arranged for the disposal of the hazardous substances found at 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 responsible classes of persons the costs of such action. In the course of its operations, the Company may have generated and may generate wastes that fall within CERCLA's definition of "hazardous substances". The Company may also be an owner of facilities on which "hazardous substances" have been released by previous owners or operators. The Company may be responsible under CERCLA for all or part of the costs to clean up facilities at which such wastes have been released. Neither the Company nor, to its knowledge, its Predecessor Partnerships has been named a potentially responsible person under CERCLA nor does the Company know of any prior owners or operators of its properties that are named as potentially responsible parties related to their ownership or operation of such property.

Air Emissions. The operations of the Company are subject to local, state and Federal regulations for the control of emissions of air pollution. 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 the Company to forego construction, modification or operation of certain air emission sources, although the Company believes that in the latter cases it would have enough permitted or permittable capacity to continue its operations without a material adverse effect on any particular producing field.

Oil Pollution Act. The Oil Pollution Act of 1990 ("OPA") and regulations thereunder impose certain duties and liabilities on "responsible parties" related to the prevention of oil spills and damages resulting from such spills in United States waters. A "responsible party" includes the owner or operator of a facility or vessel, or the lessee or permittee of the area in which a facility covered by OPA is located. OPA assigns joint and several liability 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.

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 OCS waters, with higher amounts, up to $150 million based upon worst case oil-spill discharge

volume calculations. The Company believes that it currently has established adequate proof of financial responsibility for its offshore facilities.

Management believes that the Company is in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on the Company.

Competition

The Company operates 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 the Company for the minimum projected return on investment and the availability of alternate fuel sources are factors that affect the Company's ability to compete in the marketplace. The Company's competitors include major integrated oil companies and a substantial number of independent energy companies, many of which possess greater financial and other resources than the Company. The Company competes with these competitors to acquire producing properties, exploration leases, licenses, concessions and marketing agreements.

Personnel

At December 31, 2000, the Company employed 67 full time employees who represent the executive officers and key operating, exploration, financial and accounting management. The Company outsources certain administrative and operational functions to third-party service providers, which maintain large technical, operating, accounting and/or administrative staff to provide services to Nuevo and other clients. (See Note 5 to the Notes to Consolidated Financial Statements).

In a move designed to further streamline operations, improve performance and reduce costs, Nuevo brought in-house key operations and environmental safety and regulatory compliance functions. Effective January 1, 2001, Nuevo hired approximately 43 professionals in California for positions in drilling, production engineering and supervision, operations and facilities management, environmental safety and regulatory compliance and procurement. Under this new organizational structure, Nuevo currently outsources only direct field operations and certain administrative functions. All other operating and management functions related to Nuevo's oil and gas operations are now performed by Nuevo employees. As a result of this hiring process, Nuevo now has approximately 110 employees located in its offices in Houston, Texas, and Bakersfield and Orcutt, California.

Item 2. Properties

Reserves, Productive Wells, Acreage and Production

The Company holds interests in oil and gas wells located in the United States and West Africa. The Company's principal developed properties are located in California, Texas, Alabama, and offshore Congo, West Africa; undeveloped acreage is located primarily in California, Texas, Congo, Ghana and Tunisia. Estimated proved oil and gas reserves at December 31, 2000 decreased approximately 14% since December 31, 1999, primarily as a result of price revisions relating to extremely high natural gas prices which adversely affect thermal oil producing property reserves. The estimates are based on realized prices at year-end 2000, of $19.51 per Bbl and $13.94 per Mcf, and are adjusted for the effects of contractual agreements with Unocal and Amoco in connection with the California and Congo property acquisitions. (See Notes 13 and 14 to the Notes to Consolidated Financial Statements). The Company has not filed any different oil or gas reserve information with any foreign government or other Federal authority or agency.

The following table sets forth certain information, as of December 31, 2000, which relates to the Company's principal oil and gas properties:

		Net Proved Reserves (SEC) December 31, 2000			2000 Production		
	Gross Wells	Oil* (Mbbls)	Gas (Mmcf)	MBOE	Oil* (Mbbls)	Gas (Mmcf)	
U.S. PROPERTIES							
California Fields							
Cymric........................	458	50,531	7,436	51,771	4,982	746	5,
Brea Olinda...................	220	32,747	22,361	36,474	790	209	
Santa Clara...................	23	18,579	36,763	24,707	742	510	
Midway-Sunset.................	364	18,561	--	18,561	2,497	--	2,
Dos Cuadras...................	95	14,593	12,121	16,613	759	573	
Belridge......................	329	15,899	1,205	16,100	859	220	
Point Pedernales..............	12	14,334	4,620	15,104	1,867	412	1,
Pitas Point...................	9	--	23,352	3,891	--	3,863	
Buena Vista...................	194	2,640	23,208	6,508	180	1,547	
Other.........................	439	28,375	26,524	32,795	2,673	4,452	3,
Total California Fields......	2,143	196,259	157,590	222,524	15,349	12,532	17,
Other U.S. Fields							
Other U.S. Fields............	42	433	8,387	1,831	242	2,683	
Total U.S. Properties........	2,185	196,692	165,977	224,355	15,591	15,215	18,
FOREIGN PROPERTIES							
Yombo, Congo..................	31	14,921	--	14,921	1,843	--	1,
Masseko, Congo................	--	8,281	--	8,281	--	--	
Total Foreign Properties	31	23,202	--	23,202	1,843	--	1,
Unocal contingent payment......	--	--	--	--	--	--	
TOTAL PROPERTIES	2,216	219,894	165,977	247,557	17,434	15,215	19,

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* includes natural gas liquids
** pre-tax

In addition to the information presented in the above table, the Company had entered into swap arrangements on a portion of its future crude production as of December 31, 2000 (see Note 12 to the Notes to Consolidated Financial Statements). The effects of these hedges would decrease the PV-10 by approximately $39.3 million.

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The summary of SEC reserves, which is presented on the previous page, is computed based on realized prices at December 31, 2000, held constant over time (see Note 14 to the Notes to Consolidated Financial Statements). Oil and gas prices at December 31, 2000, were high compared to historical levels. Management believes that the following reserve information, which reflects fluctuating commodity pricing based on market information available at year-end, is more consistent with management's belief that the current oil and gas prices will revert to long-term historical averages. The following table sets forth this alternative reserve information as of December 31, 2000 (based on forward NYMEX price strips at December 31, 2000, beginning with $24.86 per Bbl and $6.19 per Mcf in 2001, and ending with $18.73 per Bbl and $3.58 per Mcf in 2015). Because the prices used in the following table are lower than the year-end prices Nuevo received for its production, the following does not represent information attributable to "proved reserves" as defined by the SEC.

	Estimated Market Case December 31, 2000		
	Oil* (Mbbls)	Gas (Mmcf)	MBOE
U.S. PROPERTIES			
California Fields			
Cymric	88,888	7,436	90,127
Brea Olinda	32,583	22,361	36,310
Midway-Sunset	30,117	--	30,117
Santa Clara	16,543	32,108	21,894
Belridge	18,021	1,143	18,212
Dos Cuadras	12,164	9,408	13,732
Point Pedernales	12,691	3,864	13,335
Other	24,383	64,142	35,074
Total California Fields	235,390	140,462	258,801
Other U.S. Fields			
Other U.S. Fields	417	8,077	1,763
Total U.S. Properties	235,807	148,539	260,564
FOREIGN PROPERTIES			
Yombo, Congo	14,869	--	14,869
Masseko, Congo	8,123	--	8,123
Total Foreign Properties	22,992	--	22,992
Unocal contingent payment	--	--	--
TOTAL PROPERTIES	258,799	148,539	283,556

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* includes natural gas liquids
** pre-tax

In addition to the information presented in the above table, the Company had entered into swap arrangements on a portion of its future crude production as of December 31, 2000 (see Note 12 to the Notes to Consolidated Financial Statements). The effects of these hedges would decrease the PV-10 by approximately $19.6 million.

Acreage

The following table sets forth the acres of developed and undeveloped oil and gas properties in which the Company held an interest as of December 31, 2000. Undeveloped acreage is considered to be those 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 in the following table refers to the number of acres in which a working interest is owned directly by the Company. The number of net acres is the sum of the fractional ownership of working interests owned directly by the Company in the gross acres expressed as a whole number and percentages thereof. A "net acre" is deemed to exist when the sum of the Company's fractional ownership of working interests in gross acres equals one.

	Gross	Net
Developed Acreage	206,321	122,435
Undeveloped Acreage	4,416,134	1,739,944
Total	4,622,455	1,862,379

The following table sets forth the Company's undeveloped acreage as of December 31, 2000:

	Gross	Net
California	245,029	121,195
Texas	24,023	7,379
Alberta, Canada	22,140	11,070
Congo, West Africa:		
Marine 1 Permit	38,000	19,000
Ghana, West Africa:		
Accra-Keta	1,900,000	950,000
Tunisia, North Africa	2,171,000	623,120
Other	15,942	8,180
Total	4,416,134	1,739,944

Productive Wells

The following table sets forth the Company's gross and net interests in productive oil and gas wells as of December 31, 2000. Productive wells are producing wells and wells capable of production.

	Gross	Net
Oil Wells	2,072	1,705
Gas Wells	144	80
Total	2,216	1,785

Production

The Company's principal production volumes for the year ended December 31, 2000, were from California and offshore Congo.

Data relating to production volumes, average sales prices, average unit production costs and oil and gas reserve information appears in Note 14 to the Notes to Consolidated Financial Statements.

Drilling Activity and Present Activities

During the three year period ended December 31, 2000, the Company's principal drilling activities occurred in the continental United States and offshore in state and federal waters, and offshore the Congo in West Africa.

The Company believes that its demonstrated ability to reduce operating costs to levels well below those of the larger oil and gas companies from which acquisitions have been made allows it to compete successfully in an industry characterized by fluctuating commodity prices.

As of December 31, 2000, the Company had drilled 360 wells in the Cymric field in central California, which contained 21% of the Company's total estimated net proved equivalent reserves at December 31, 2000, and anticipates drilling approximately 30 wells in the Cymric field during 2001. In the Midway-Sunset field in central California, which contained 7% of the total estimated net proved equivalent reserves at December 31, 2000, the Company drilled 40 wells during 2000, and plans to defer future development in this field until 2002. In the Belridge field in central California, which contained 7% of the total estimated net proved equivalent reserves at December 31, 2000, the Company drilled 20 wells during 2000, and plans to drill approximately 9 wells in 2001.

In 1999, the Company initiated a waterflood project in the Yombo field offshore Congo to enhance production from existing Upper Sendji and Tchala zones. The Company continued its development drilling program in the Yombo field during 2000 and repaired a pipeline from one of its platforms. Plans for 2001 include the drilling of three to four development wells, expansion of the waterflood program and replacing pipelines from the two platforms.

The Company's most significant discovery in 2000 was the 701 well on its Star Fee lease in the Cymric Field in California, which was acquired from Texaco in 1999. The Star Fee 701 deep well tested at a rate of over 900 BOPD and 1.2 million cubic feet of gas per day, and has already produced over 216 equivalent barrels since August 2000. The Company owns a 100% working and net revenue interest in this well, which is currently producing at rates over 660 BOPD. As a result of this success, additional exploratory wells have been scheduled for drilling in 2001 to further test the deep geologic model. The Company's most significant discoveries in 1998 were: (i) four successful wells at Four Isle Dome in Louisiana, which helped increase net production from 0.6 MMCFPD and 35 BOPD at the beginning of 1998 to 7.9 MMCFPD and 170 BOPD at the end of 1998; (ii) two successful wells at Weeks Island, Louisiana, which each resulted in completions producing in excess of 700 BOPD (the Company's interest in Weeks Island was sold in 1999); and (iii) successful extension to the south and east at the Monument Junction reservoir in the Cymric Field in California.

The Company had two gross (two net) wells in progress at December 31, 2000. The following table sets forth the results of drilling activity by the Company, net to its interest, for the last three calendar years. Gross wells, as it applies to wells in the following tables, refers to the number of wells in which a working interest is owned directly by the Company. The number of net wells is the sum of the fractional ownership of working interests owned directly by the Company in gross wells expressed as whole numbers and percentages thereof.

	Exploratory Wells				
	Gross			N	
	Productive	Dry Holes	Total	Productive	D Ho
1998	8	6	14	4.09	3.5
1999	--	4	4	--	2.3
2000	11	2	13	11	1.4

	Development Wells				
	Gross			N	
	Productive	Dry Holes	Total	Productive	D Ho
1998	155	--	155	134.43	
1999	44	1	45	40.21	0
2000	175	3	178	173.25	2

Exit Cost Liabilities

With respect to the Company's offshore oil and gas operations in California, the Company has significant exit cost liabilities. These liabilities include costs for dismantlement, rehabilitation and abandonment. As of December 31, 2000, the Company's net liability for these exit costs was approximately $82.1 million. The Company is not indemnified for any part of these exit costs.

Gas Plant, Pipelines and Other Facilities

As of December 31, 2000, the Company owned interests in the following gas plant facilities:

Facility	State	Operator	Capacity MMCFD	2000 Throughput MMCFD
Stearns Gas Plant	California	Nuevo Energy Company	5	3.2
HS&P Gas Plant	California	Nuevo Energy Company	13	3.1

Risk Factors

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 the control of the Company. These factors include weather conditions in the United States, the condition of the United States economy, the actions of 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. Any substantial and extended decline in the price of oil or gas would have an adverse effect on the Company's carrying value of its proved reserves, borrowing capacity, the Company's ability to obtain additional capital, and its 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 the Company's production is California heavy oil. The market price for California heavy oil differs substantially from the established market indices for oil and gas, due principally 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 for 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 "Hedging" below for discussion of 15-year crude oil contract).

Reserve Replacement Risks

The Company's future performance depends upon its ability to find, develop and acquire additional oil and gas reserves that are economically recoverable. Without successful exploration, exploitation or acquisition activities, the Company's reserves and revenues will decline. No assurances can be given that the Company 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 the Company's exploitation and development activities will result in any increase in reserves. The Company's 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

The Company makes, and will continue to make, substantial capital expenditures for the exploitation, exploration, acquisition and production of oil and gas reserves. Historically, the Company has financed these expenditures primarily with cash generated by operations, proceeds from bank borrowings and the proceeds of debt and equity issuances. The Company believes that it will have sufficient cash provided by operating activities and borrowings under its bank credit facility to fund planned capital expenditures. If revenues or the Company's borrowing base decreases as a result of lower oil and gas prices, operating difficulties or declines in reserves, the Company 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 of the Company will depend upon its ability to develop, produce and sell its 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

Nuevo's 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 to the Company 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. Moreover, 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. The Company's 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. The Company 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 the Company's financial condition and results of operations. The Company maintains insurance coverage for its operations, including limited coverage for sudden environmental damages and for existing contamination, but does not believe that insurance coverage for environmental damages that occur over time is available at a reasonable cost. Moreover, the Company does not believe that insurance coverage for the full potential liability that could be caused by sudden environmental damages is available at a reasonable cost. Accordingly, the Company may be subject to liability or may lose substantial portions of its properties in the event of certain environmental damages.

California Natural Gas and Electricity Markets

The price of natural gas and the threat of electrical disruptions are factors that create volatility in the Company's California oil and gas operations. Because of the recent developments in these commodities, Nuevo has made significant changes in its natural gas disposition and electricity production in California. Regarding natural gas, Nuevo has a net long position in California - producing more natural gas than consumed in thermal crude production. Moreover, as gas prices escalated in late 2000, Nuevo began to exploit this gas position by diverting gas consumed in uneconomic cyclic steaming operations to gas sales. In January and February 2001, Nuevo sold an average of 19 MMcfd, or 44% of its total daily gas production, which resulted in an increase in gas sales of 33%. This strategy will remain as long as gas prices support sales over thermal oil production.

In California, Nuevo generates a total of 22.5 Megawatts ("MW") of power at various sites. Two turbines came on-line at the Company's Brea Olinda field using gas previously flared. Three turbines in Kern County produce 12 MW of power and cogenerate 15% of Nuevo's total steam needs in thermal operation. By self-generating power consumption in Kern County, Nuevo has reduced it exposure to rising electricity prices. With the exception of the Point Pedernales field, for which the Company has contracted for firm electric power service, Nuevo's facilities receive power under interruptible service contracts. Considering the fact that California is short of electricity and some Nuevo facilities receive interruptible service, the Company could experience periodic power interruptions. In addition, the State of California could change existing rules or impose new rules or regulations with respect to power that could impact the Company's operating costs.

Foreign Investments

The Company's 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. The Company attempts to conduct its business and financial affairs so as to protect against political and economic risks applicable to operations in the various countries where it operates, but there can be no assurance the Company will be successful in protecting against such risks.

The Company's 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, the Company 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.

The Company's private ownership of oil and gas reserves under oil and gas leases in the United States differs distinctly from its ownership of foreign oil and gas properties. In the foreign countries in which the Company does 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.

Hedging

During 1999, the Company formalized its policies regarding the management of price risk to ensure the Company's ability to optimally manage its portfolio of investment opportunities. In a typical swap transaction, the Company 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, the Company is required to pay the counterparty the difference. The Company would be required to pay the counterparty the difference between such prices regardless of whether the Company's

production was sufficient to cover the quantities specified in the hedge. In addition, the index used to calculate the floating price in a hedge is frequently not the same as the prices actually received for the production hedged. The difference (referred to as basis differential) may be material, and may reduce the benefit or increase the detriment caused by a particular hedge. 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. Consequently, prior to 2000, hedging California heavy crude oil was particularly subject to the risks associated with volatile basis differentials. In February 2000, the Company entered into a 15-year contract, effective January 1, 2000, to sell substantially all of its current and future California crude oil production to Tosco Corporation. The contract provides pricing based on a fixed percentage of the NYMEX crude oil price for each type of crude oil that Nuevo produces in California. Therefore, the actual price received as a percentage of NYMEX will vary with the Company's production mix. Based on the Company's current production mix, the price received by Nuevo for its California oil production is expected to average approximately 72% of WTI. While the contract does not reduce the Company's exposure to price volatility, it does effectively eliminate the basis differential risk between the NYMEX price and the field price of the Company's California oil production, thereby facilitating Nuevo's ability to hedge its realized prices.

As a result of hedging transactions, oil and gas revenues were reduced by $117.7 million and $44.9 million in 2000 and 1999, respectively, and increased by $0.6 million in 1998. For 2001, the Company has entered into swap arrangements on 26,000 BOPD for the first quarter at an average WTI price of

$19.52, for the second quarter on 25,000 BOPD at an average WTI price of $19.54, for the third quarter on 20,000 BOPD at an average WTI price of $21.22, and for the fourth quarter on 15,500 BOPD at an average WTI price of $22.95 per barrel. Subsequent to December 31, 2000, the Company entered into swaps on an additional 1,200 BOPD for the second quarter, bringing the total to 26,200 BOPD at an average price of $19.84 per barrel. On a physical volume basis, these hedges cover 47% of the Company's estimated 2001 oil production. At December 31, 2000, the market value of the swaps in place for 2001 was a loss of $35.1 million. For 2002, the Company has entered into swap arrangements on 12,500 BOPD for the first quarter at an average WTI price of $25.91 per barrel. For the remainder of 2002, the Company purchased put options with a WTI strike price of $22.00 per barrel, on 19,000 BOPD for the second quarter, and on 14,000 BOPD for both the third and fourth quarters. At December 31, 2000, the market value of the 2002 hedge positions is a gain of $8.3 million. See Item 7a. "Quantitative and Qualitative Disclosures About Market Risk".

Risk Management Policy

The Board of Directors adopted a risk management policy, which was implemented by management and is periodically assessed by the Governance Committee of the Board. The Company's policy is designed to meet the following goals: (i) to assure the Company can generate sufficient operating cash flow to replace reserves that are produced and (ii) to assure compliance with restrictive debt covenants that would otherwise limit the Company's ability to incur additional debt. It is also the Company's policy that significant capital investments whose rates of return are sensitive to future oil and gas prices be protected from exposure to extreme price volatility.

The Company's 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, the Company will hedge as much of its production as is necessary to meet its policy goals for that period. Variations from this policy require Board approval. The risk management policy states that hedging activity that is speculative or otherwise unrelated to the Company's normal business activities is considered inappropriate. The Company recognizes the risks inherent in price management. In order to minimize such risk, the Company has instituted a set of controls addressing approval authority, trading limits and other control procedures. All hedging activity is the responsibility of the Chief Financial Officer. In addition, Internal Audit, which independently reports to the Audit Committee, reviews the Company's price management activity.

Competition/Markets for Production

The Company operates 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 standards established by the Company for the minimum projected return on investment, the availability of alternate fuel sources and the intermediate transportation of oil and gas are factors which affect the Company's ability to compete

in the marketplace. The Company's competitors include major integrated oil companies and a substantial number of independent energy companies, many of which possess greater financial and other resources than the Company.

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

Environmental and Other Regulation

The Company's operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, and impose substantial liabilities for pollution which might result from the Company's operations. Moreover, the recent trend toward stricter standards in environmental legislation and regulation is likely to continue. For instance, legislation has been proposed in Congress from time to time that would reclassify certain oil and gas exploration and production wastes as "hazardous wastes" which would make the reclassified wastes subject to much more stringent handling, disposal and cleanup requirements. If such legislation were to be enacted, it could have a significant impact on the operating costs of the Company, as well as the oil and gas industry in general. Initiatives to further regulate the disposal of oil and gas wastes are also pending in certain states, and these various initiatives could have a similar impact on the Company. The Company could incur substantial costs to comply with environmental laws and regulations.

The OPA imposes a variety of regulations on "responsible parties" related to the prevention of oil spills. The implementation of new, or the modification of existing, environmental laws or regulations, including regulations promulgated pursuant to the OPA, could have a material adverse impact on the Company.

ITEM 3. LEGAL PROCEEDINGS

The Company had been named as a defendant in Gloria Garcia Lopez and Husband, Hector S. Lopez, Individually, and as successors to Galo Land & Cattle Company v. Mobil Producing Texas & New Mexico, et al. in the 79th Judicial District Court of Brooks County, Texas. On June 9, 2000, the parties entered into a memorandum of settlement agreement, pursuant to which the lawsuit was dismissed, the defendants paid the plaintiffs $12.0 million and the lease agreement was amended. Nuevo's working interest in these properties is 20%, and its share of the settlement payment was approximately $2.4 million.

On September 22, 2000, the Company was named as a defendant in the lawsuit Thomas Wachtell et al. versus Nuevo Energy Company in the Superior Court of Los Angeles County, California. The plaintiffs, who own certain interests in the Point Pedernales properties, have asserted numerous causes of action including breach of contract, fraud and conspiracy in connection with the plaintiff's allegation that: (i) royalties have not been properly paid to them for production from the Point Pedernales field, (ii) payments have not been made to them related to production from the Sacate field, and, (iii) the Company has failed to recognize the plaintiff's interests in the Tranquillon Ridge project. The plaintiffs have not specified damages. The Company has not yet been required to file an answer, but believes the allegations are without merit and intends to vigorously contest these claims. Management does not believe that the outcome of this matter will have a material adverse impact on the Company's operating results, financial condition or liquidity.

On April 5, 2000, the Company filed a lawsuit against ExxonMobil Corporation in the United States District Court for the Central District of California, Western Division. The Company and ExxonMobil each own a 50% interest in the Sacate Field, offshore Santa Barbara County, California, which can only be accessed from an existing ExxonMobil platform. The Company has alleged that by grossly inflating the fee that ExxonMobil insists the Company must pay to use an existing ExxonMobil platform and production infrastructure, ExxonMobil failed to submit a proposal for the development of the Sacate field consistent with the Unit Operating Agreement. The Company therefore believes that it has been denied a reasonable opportunity to exercise its rights under the Unit

Operating Agreement. ExxonMobil contends that Nuevo had not consented to the operation and therefore cannot receive its share of production from Sacate until ExxonMobil has first recovered certain costs and fees. As a result, Nuevo has neither received revenues, incurred operating expenses, nor booked any proved reserves related to Sacate. The Company has alleged that ExxonMobil's actions breach the Unit Operating Agreement and the covenant of good faith and fair dealing. The Company is seeking damages and a declaratory judgment as to the payment that must be made to access ExxonMobil's platform and facilities. The Company's capitalized costs associated with Sacate are insignificant.

The Company has been named as defendant in certain other lawsuits incidental to its business. Management does not believe that the outcome of such litigation will have a material adverse impact on the Company's operating results or financial condition. However, these actions and claims in the aggregate seek substantial damages against the Company and are subject to the inherent uncertainties in any litigation. The Company is defending itself vigorously in all such matters.

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

There were no matters submitted to a vote of security holders during the fourth quarter of 2000.

PART II

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

The principal market on which the Company's Common Stock is traded is the New York Stock Exchange (Symbol: NEV). On March 22, 2001, Nuevo had 16,505,768 shares of common stock outstanding and had reserved 1,936,830 shares of common stock for issuance upon conversion of the TECONS and 225,534 shares for issuance pursuant to employee stock options. There were approximately 1,076 stockholders of record and approximately 2,472 additional beneficial owners as of March 22, 2001. The Company has not paid dividends on its Common Stock and does not anticipate the payment of cash dividends in the immediate future as it contemplates the use of cash flows for expansion of its operations. In addition, certain restrictions contained in the Company's financing arrangements restrict the payment of dividends (See Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity and Note 6 to the Notes to Consolidated Financial Statements). The high and low recorded prices of the Company's Common Stock during 2000 and 1999 are presented in the following table:

	Market Price	
	High	Low
Quarter Ended:		
March 31, 2000	$26.00	$15.5
June 30, 2000	$22.06	$16.8
September 30, 2000	$20.25	$14.3
December 31, 2000	$21.00	$14.6
March 31, 1999	$16.38	$ 6.1
June 30, 1999	$18.19	$11.6
September 30, 1999	$18.13	$13.5
December 31, 1999	$19.50	$13.6

Treasury Stock Repurchases

Since December 1997, the Board of Directors of the Company authorized the open market repurchase of up to 4,616,600 shares of outstanding Common Stock at times and at prices deemed appropriate by management. During 2000, the Company repurchased 1,482,000 shares of its Common Stock in open market transactions at an average purchase price, including commissions, of $16.67 per share. During 1999, the Company repurchased 1,999,100 shares of its Common Stock in open market transactions at an average purchase price, including commissions, of $16.50 per share. No Common Stock was repurchased during 1998. As of March 22, 2001, the Company had repurchased 3,608,900 shares, on a cumulative basis, at an average purchase price of $16.56 per share, including commissions, under the current share repurchase program.

Shareholder Rights Plan

In March 1997, the Company adopted a Shareholder Rights Plan to protect the Company's 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 the prior consent of the Company, or the Company is acquired in a merger or other business combination, or 50% or more of its 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. The Company 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 the Board of Directors of the Company.

On January 10, 2000, the Company amended the Shareholder Rights Plan to provide that if the Company receives and consummates 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

During July 1997, the Board of Directors of the Company adopted a plan to encourage senior executives to personally invest in the stock of the Company, 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 Common Stock of the Company at a discount to market prices or make other investments at the employee's discretion. Stock acquired at a discount will be held in a benefit trust and will be restricted for a two-year period. The Plan does not permit investment in a diversified equity portfolio until and unless targeted levels of Common Stock ownership in the Company are achieved and maintained. 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.

NUEVO ENERGY COMPANY

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data with respect to the Company should be read in conjunction with the consolidated financial statements and supplementary information included in Item 8 (amounts in thousands, except per share data).

	As of and for the Years ended De		
	2000	1999	1998
Oil and gas revenues..............	$331,655	$242,274	$242,675
Gas plant revenues................	--	--	--
Pipeline and other revenues.......	--	--	--
Gain on sale of assets, net.......	657	85,294	5,768
Interest and other income.........	4,293	4,667	4,260
Total revenues..................	336,605	332,235	252,703
Total costs and expenses before extraordinary item and cumulative effect (including income taxes and minority interest)/(2)/...................	324,174	300,793	346,975
Cumulative effect of a change in accounting principle............	796	--	--
Extraordinary loss on early extinguishment of debt...........	--	--	--

Net income (loss)/(1)(3)/.........	$ 11,635	$ 31,442	$(94,272)
Net income (loss) attributable to Common Stockholders..............	$ 11,635	$ 31,442	$(94,272)
Earnings (loss) per Common Share - Basic..........................	$0.67	$ 1.62	$ (4.77)
Earnings (loss) per Common Share - Diluted........................	$0.64	$ 1.61	$ (4.77)
Total Assets......................	$848,024	$760,030	$817,685
Long-term debt, net of current maturities.......................	$409,727	$340,750	$419,150
Company-obligated Mandatorily Redeemable Convertible Preferred Securities of Nuevo Financing I..	$115,000	$115,000	$115,000

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(1) No Common Stock dividends have been declared since the formation of the Company. See Note 6 to the Notes to Consolidated Financial Statements concerning restrictions on the payment of Common Stock dividends.

(2) Results for the years ended 1998 and 1997 include impairments of oil and gas properties of $68.9 million and $30.0 million, respectively, and (revision to) provision for impairment on assets held for sale of ($3.7) million and $23.9 million, respectively.

(3) The year ended December 31, 1996, includes activity of the California Properties from the date of acquisition (April 9, 1996).

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NUEVO ENERGY COMPANY

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

Overview

Nuevo, headquartered in Houston, Texas, is primarily engaged in the exploration for, and the acquisition, exploitation, development and production of crude oil and natural gas. The Company's strategy to differentiate itself from its numerous peer group competitors and to generate long term shareholder value consists of: (i) a management philosophy that frames all important decisions in terms of anticipated impact on per share (rather than absolute) growth of reserves, production, cash flow and net asset value; (ii) a contrarian investment and financing orientation, in which the Company seeks to purchase assets during periods of industry weakness and sell assets during periods of industry strength; (iii) the outsourcing of non-strategic functions; and (iv) the alignment of employee compensation structures with shareholder objectives. Nuevo is also committed to an exemplary corporate governance structure, which reinforces management's overarching view that Nuevo should be a conduit for shareholders to achieve superior long-term capital gains. All of Nuevo's directors, other than the chief executive officer, are independent directors. Nuevo's directors and executive officers each have made substantial equity investments in Nuevo, in order to align their interests with that of the Company's stockholders.

Nuevo is an independent energy company. Since its inception in 1990, Nuevo has expanded its operations through a series of disciplined, low-cost acquisitions of oil and gas properties and the subsequent exploitation and development of these properties. The Company has complemented these efforts with divestitures of non-core assets and an opportunistic exploration program, which provides exposure to high-potential prospects. The Company's primary strengths are its large inventory of exploitation projects in its core areas of operation, which the Company believes will support future growth in reserves and production per share; its ability to identify and acquire, at attractive prices, long-lived producing properties, which have significant potential for further exploration, exploitation and development; a capital structure supportive of a growing investment program and future acquisitions; and a price risk management policy designed to protect the Company's ability to generate self-sustaining cash flow and to meet the interest coverage tests under the Company's bond indentures.

The Company's results of operations have been significantly affected by fluctuations in oil and gas prices. The Company's success in acquiring oil and gas properties and its ability to maintain or increase production through its exploitation activities have also significantly affected the Company's results. The following table reflects the Company's oil and gas production and its average oil and gas prices (inclusive of crude oil and natural gas price swaps), by oil and gas segment and in total, for the periods presented:

	Year Ended December 31,	
Production:	2000	1999
Oil (MBBLS):		
Domestic	15,413	15,685
Foreign	1,843	1,835
Total	17,256	17,520
Natural gas (MMCF):		
Domestic	15,215	17,620
Natural gas liquids (MBBLS):		
Domestic	178	207

	Year Ended December 31,	
Average sales price:	2000	1999
Oil (per barrel):		
Domestic	$21.73	$13.59
Foreign	$22.19	$16.69
Total - exclusive of hedges	$21.88	$13.82
Total - hedge effect	$(7.13)	$(2.61)
Total - net of hedge effect	$14.75	$11.21
Natural gas (per MCF):		
Domestic/Total - exclusive of hedges	$ 4.78	$ 2.27

Domestic/Total - hedge effect...........	$ ---	$ ---
Domestic/Total - net of hedge effect.....	$ 4.78	$ 2.27
AVERAGE UNIT PRODUCTION COST PER EQUIVALENT BARREL (6 MCF EQUALS 1 BARREL):		
Domestic................................	$ 7.88	$ 6.07
Foreign.................................	$ 7.39	$ 7.01
Total...................................	$ 7.84	$ 6.15

The Company utilizes the successful efforts method of accounting for its investments in oil and gas properties. Under the successful efforts method of accounting, 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.

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. An impairment of unproved leasehold costs of $8.1 million was recognized as of December 31, 1998. No such impairment was recognized for the years ended December 31, 2000 or 1999. Exploration costs, including geological and geophysical expenses, exploratory dry holes and delay rentals, are charged to expense as incurred.

Costs of successful wells, development dry holes and proved leases are capitalized and depleted on a unit-of-production basis over the life of the remaining proved reserves. Capitalized drilling costs are depleted on a unit-of-production basis over the life of the remaining proved developed reserves. Estimated costs (net of salvage value) of dismantlement, abandonment and site remediation are computed by the Company and an independent consultant and are included when calculating depreciation and depletion using the unit-of-production method.

In accordance with SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of", the Company reviews its 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. 121 requires an impairment loss be recognized when the carrying amount of an asset exceeds the sum of the undiscounted estimated future cash flows. In this circumstance, the Company recognizes 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 present value of expected future net cash flows from proved reserves, utilizing a risk-adjusted rate of return.

During 1998, the Company recorded a fair value impairment totaling $60.8 million on its East Coalinga, Las Cienegas, Beta, Point Pedernales and South

Mountain fields and certain other insignificant oil and gas properties due to the significant, sustained decline in domestic oil prices during the year from an average Company realized price of $14.86 per barrel for 1997 to an average realized price of $9.25 per barrel in 1998. No such impairment was recognized during 2000 or 1999.

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

Financing Activities

The Company had $409.7 million in outstanding indebtedness at December 31, 2000, which is scheduled to mature as follows (amounts in thousands):

2001	$ --
2002	--
2003	--
2004	--
2005	--
Thereafter	409,727
	$409,727

On September 26, 2000, the Company issued $150.0 million of 9-3/8% Senior Subordinated Notes due September 15, 2010 ("9-3/8% Notes"). Interest on the 9-3/8% Notes accrues at the rate of 9-3/8% per annum and is payable semi-annually in arrears on April 1 and October 1. The 9-3/8% Notes are redeemable, in whole or in part, at the option of the Company, on or after October 1, 2005, under certain conditions. The Company is not required to make mandatory redemption or sinking fund payments with respect to the 9-3/8% 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. If a subsidiary of the Company guarantees other subordinated indebtedness of the Company, the subsidiary must also guarantee the 9-3/8% Notes. Currently, none of the Company's subsidiaries guarantees subordinated indebtedness of the Company. The 9-3/8% Notes are unsecured general obligations of the Company, and are subordinated in right of payment to all existing and future senior indebtedness of the Company. In the event of a defined change in control, the Company will be required to make an offer to repurchase all outstanding 9-3/8% Notes at 101% of the principal amount thereof, plus accrued and unpaid interest to the date of redemption.

In July 1999, the Company authorized a new issuance of $260.0 million of 9-1/2% Senior Subordinated Notes due June 1, 2008 ("9-1/2% Notes"). The Company offered to exchange the new notes for its outstanding $160.0 million of 9-1/2% Senior Subordinated Notes due 2006 ("Old 9-1/2% Notes") and $100.0 million of 8-7/8% Senior Subordinated Notes due 2008 ("8-7/8 % Notes"). In August 1999, the Company received tenders to exchange $157.5 million of its Old 9-1/2% Notes and $99.85 million of the 8-7/8% Notes. In connection with the exchange offers, the Company solicited consents to proposed amendments to the indentures under which the old notes were issued. These amendments streamline the Company's covenant structure and provide the Company with additional flexibility to pursue its operating strategy. The exchange was accounted for as a debt modification. As such, the consideration that the Company paid to the holders of the Old 9-1/2% Notes who tendered in the exchange offer (equal to 3% of the outstanding principal amount of the Old 9-1/2% Notes exchanged) was accounted for as deferred financing costs. Also in connection with this exchange offer, the Company incurred a total of $3.1 million in third-party fees during the third and fourth quarters of 1999, which are included in other expense.

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

Nuevo's Third Amended and Restated Credit Agreement, (the "Credit Agreement"), dated June 7, 2000, provides for secured revolving credit availability of up to $410.0 million (subject to a semi-annual borrowing base determination) 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.

The borrowing base is subject to a semi-annual borrowing base determination within 60 days following March 1 and August 15 of each year. The borrowing base determination establishes the maximum borrowings that may be outstanding under the credit facility, and is determined by a 60% vote of the 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 the Company's oil and gas reserves based on its own assumptions regarding future prices, production, costs, risk factors and discount rates, and (ii) on 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, the Company would be required to repay such excess over a defined period of time. As of December 31, 2000, the Company's borrowing base was $225.0 million. There were no outstanding borrowings under this facility at December 31, 2000.

Amounts outstanding under the credit facility bear interest at a rate equal to the London Interbank Offered Rate ("LIBOR") plus an amount which increases as borrowing base utilization increases.

The Credit Agreement has customary covenants including, but not limited to, covenants with respect to the following matters: (i) limitations on certain restricted payments and investments; (ii) limitations on guarantees and indebtedness; (iii) limitations on prepayments of subordinated and certain other indebtedness; (iv) limitations on mergers and consolidations, on certain types of acquisitions and on the issuance of certain securities by subsidiaries; (v) limitations on liens; (vi) limitations on sales of properties; (vii) limitations on transactions with affiliates; (viii) limitations on derivative contracts; and (ix) limitations on debt in subsidiaries. The Company is 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. As a result of reduced revenues in 1998 due to falling oil prices, the Company obtained amendments for relief from the EBITDAX fixed charge coverage test through March 31, 2000. The Company was in compliance with this test and all other covenants of the Credit Agreement at December 31, 2000, and does not anticipate any issues of non-compliance arising in the foreseeable future.

In February 1995, in connection with the purchase of the stock of the Amoco Congo Petroleum Company, the Company negotiated with the Overseas Private Investment Corporation ("OPIC") and an agent bank for a non-recourse credit facility in the amount of $25.0 million. The credit facility expired in June 1999. The initial drawdown on the facility was $8.8 million to finance a portion of the purchase price. A portion of the remaining outstanding commitment, $6.0 million, was drawn down in January 1996 to fund the first phase of the development drilling program in the Congo. This loan agreement required a sixteen-quarter repayment period and was fully re-paid in April 2000.

At present, there is no plan to pay dividends on Common Stock. The Company maintains a policy of reinvesting its discretionary cash flows for the expansion of its business and operations.

Results of Operations

Revenues

The Company has experienced significant oil and gas revenue volatility in recent years. Beginning in late 1997 and continuing through early 1999, oil prices were very low compared with historical prices. Oil prices improved significantly during 1999 and 2000. During this three-year period, the volatility of oil and gas prices directly impacted revenues. For the purpose of reducing exposure to decreases in oil and gas prices, the Company utilizes derivative financial instruments in accordance with its price risk management policy, which was adopted in 1999. As a result of such hedging transactions, oil and gas revenues were reduced by $117.7 million and $44.9 million in 2000 and 1999, respectively, and increased by $0.6 million in 1998.

Oil and gas revenues for 2000 were 37% higher than 1999 oil and gas revenues primarily due to a 32% increase in average realized oil prices and a 111% increase in average realized gas prices from 1999 to 2000. Partially offsetting these increases in realized prices, the Company's gas production decreased 14% from 1999 to 2000, and oil production decreased 2% from 1999 to 2000. The production decreases were primarily a result of asset sales. Oil and gas revenues for 1999 were relatively flat as compared to 1998, however the factors driving oil and gas revenues for each period were different. The 15% decrease in oil and gas production from 1998 to 1999 was almost entirely offset by higher commodity prices received in 1999. Oil volumes decreased 6% from 1998 to 1999 primarily as a result of reduced capital spending during 1999. This decrease was partially offset by the production from the California properties acquired from Texaco in June 1999. Gas volumes decreased 46% from 1998 to 1999 principally due to the January 1999 sale of the East Texas natural gas assets, and to a lesser extent, natural field declines in California. Offsetting these production declines, oil and gas price realizations increased 21% and 14%, respectively, from 1998 to 1999.

The net gain on sale of assets for 2000 was $657,000, primarily representing a $923,000 gain on the sale of the Company's working interest in the Las Cienegas field in California, which was partially offset by a $266,000 net loss on the sale of several individually insignificant non-core assets. The net gain on sale of assets for 1999 was $85.3 million, which is comprised of: (i) an $80.2 million gain on the sale of the Company's East Texas natural gas assets in January 1999, (ii) a $5.4 million gain on the sale of the Company's interest in 13 onshore fields and a gas processing plant located in Ventura County, California, in December 1999, and (iii) a $0.3 million net loss on the sale of other non-core properties. Gain on sale of assets for 1998 was $5.8 million. This gain on sale of assets includes a $4.1 million gain on the sale of the Company's interest in the Sansinena field in California in the third quarter of 1998 and a $1.7 million gain on the sale of the Company's interest in the Coke field in Chapel Hill, Texas in the first quarter of 1998.

Interest and other income for the year ended December 31, 2000, of $4.3 million includes $1.9 million in interest income resulting from higher cash balances in 2000 plus $1.5 million for a partial reimbursement of previously expensed funds, resulting from a negotiated settlement of a legal claim (see Note 11 to the Notes to Condensed Consolidated Financial Statements), as well as several individually insignificant items. Interest and other income for the year ended December 31, 1999, of $4.7 includes $2.4 million associated with interest earned on the $100.0 million in proceeds from the sale of the East Texas natural gas properties funded into an escrow account to provide "like-kind exchange" tax treatment in the event the Company acquired domestic producing oil and gas properties in the first half of 1999. The escrow account was liquidated in June 1999, in connection with the Company's June 1999 acquisition of certain California oil and gas properties from Texaco, Inc. and the repayment of a portion of bank debt. Also included in interest and other income in 1999 is $0.6 million related to the sale of an unconsolidated subsidiary. Interest and other income for the year ended December 31, 1998, of $4.3 million includes $2.7 million in pipeline revenue as well as several individually insignificant items.

Expenses

Lease operating expenses ("LOE") for 2000 totaled $156.5 million, as compared to $130.5 million and $137.9 million for 1999 and 1998, respectively. The 20% increase in LOE from 1999 to 2000 is primarily due to a $25.7 million increase in steam costs resulting from higher natural gas prices. The 5% decrease in LOE from 1998

to 1999 is primarily due to the Company's sale of the East Texas natural gas assets in January 1999. Even though total LOE decreased in 1999, LOE per BOE increased 11% from 1998 to 1999. This increase primarily relates to the January 1999 sale of the East Texas assets that had relatively low LOE per BOE rates.

Exploration costs, including geological and geophysical ("G&G") costs, dry hole costs and delay rentals, were $9.8 million, $14.0 million and $16.6 million for the years ended December 31, 2000, 1999 and 1998, respectively. Exploration costs for the year ended 2000 included: $2.5 million of dry hole costs, $5.4 million of G&G costs, $0.1 million of delay rentals and $1.8 million of other exploration costs. Exploration costs for the year ended 1999 included: $8.1 million of dry hole costs ($7.2 million of which relates to onshore California), $3.6 million of G&G costs ($2.1 of which relates to Ghana), $0.8

million of delay rentals and $1.5 million of other exploration costs. Exploration costs for the year ended 1998 included: $13.0 million of dry hole costs ($7.3 million of which relates to Ghana), $2.1 million of G&G costs ($1.5 million of which relates to Ghana), $0.9 million of delay rentals and $0.6 million of other exploration costs.

Depreciation, depletion and amortization decreased 16% in 2000 as compared to 1999. This decrease was driven by a lower depletion rate, which primarily resulted from a significant increase in reserve estimates attributable to higher commodity prices at year-end 1999 versus year-end 1998. Depreciation, depletion and amortization decreased 5% in 1999 as compared to 1998. This decrease is primarily due to the impairment of oil and gas properties of $60.8 million recognized in the fourth quarter of 1998, which reduced the capitalized costs to be depleted in 1999. Also, the East Texas properties were depleted for the first six months in 1998. The Company discontinued depleting these assets in the third quarter of 1998, when it was decided to sell these properties. The 5% decrease was partially offset by higher international depletion due to increased production.

The Company recorded a provision for impairment of oil and gas properties in 1998 in the amount of $68.9 million ($60.8 million of fair value impairments plus $8.1 million of unproved leasehold cost impairments). These impairments were recorded as a result of declines in the price of oil, which caused capitalized costs to be in excess of future net revenues. No such impairment was recognized during 2000 or 1999.

In December 1997, the Company recorded a provision for impairment on assets held for sale, in connection with its plans to dispose of its non-core gas gathering, pipeline and gas storage assets during 1998, including all such assets except its California gas plants. A positive revision to this charge was made in the fourth quarter of 1998 in the amount of $3.7 million to reflect the estimated current fair market value of the Illini pipeline.

General and administrative expenses ("G&A") increased only slightly in 2000 as compared to 1999. G&A expenses were up $4.2 million in 1999 versus 1998. The 15% increase is mainly comprised of a $1.9 million increase in bonuses paid to employees, as no bonuses were paid in 1998, and a $1.9 million increase in the market value of the Company's obligation for the executive compensation plan.

Interest expense of $37.5 million for year ended December 31, 2000, increased 13% as compared to interest expense in the same period in 1999. The increase is primarily attributable to an increase in outstanding borrowings under the Company's credit facility during the year plus higher interest rates on those outstanding borrowings. On September 26, 2000, all borrowings outstanding under the credit facility were paid off with net proceeds received from the Company's issuance of the 9-3/8% Notes (see Note 8 to the Notes to Consolidated Financial Statements). The increase is also due to higher interest rates as the Company exchanged its 8-7/8% Senior Subordinated Notes for 9-1/2% Senior Subordinated Notes due 2008 in the third quarter of 1999. Interest expense for 1999 increased slightly from 1998, however, the components of interest expense changed from year to year. The Company issued $100.0 million of 8-7/8% Senior Subordinated Notes in June 1998, which were exchanged for 9-1/2% Senior Subordinated Notes in July 1999. This increase was significantly offset by lower interest expense on the Credit Agreement as a result of lower average borrowings outstanding during 1999.

Other expense of $5.1 million in 2000 includes: a $2.0 million settlement for a lawsuit (see Note 11 to the Notes to Consolidated Financial Statements), $1.7 million for scientific information technology consulting, and $0.9 million in costs to evaluate potential business transactions. The remaining amount is made up of individually insignificant items. Other expense of $8.9 million in

1999 includes: $3.1 million in third-party charges incurred in connection with the July 1999 exchange offer (see Note 8 to the Notes to Consolidated Financial Statements), $1.6

million relating to the fraud discussed below, $1.3 million for scientific information technology consulting, and other miscellaneous charges. In March 1999, the Company discovered that a non-officer employee had fraudulently authorized and diverted for personal use Company funds totaling $5.9 million, $4.3 million in 1998 and the remainder in 1999, that were intended for international exploration. Other expense of $7.8 million in 1998 also includes $2.0 million of pipeline operating costs plus several individually insignificant items.

Dividends on the TECONS were $6.6 million in 2000, 1999 and 1998. The TECONS pay dividends at a rate of 5.75% and were issued in December 1996. (See Note 7 to the Notes to Consolidated Financial Statements.)

Income tax expense of $8.4 million was recognized in 2000, compared to a benefit of $5.4 million in 1999 and $32.6 million in 1998. The Company's effective income tax rate was 40.3%, (20.5)% and (25.7)% in 2000, 1999 and 1998, respectively. At December 31, 1998, the Company determined that it was more likely than not that a portion of the deferred tax assets would not be realized and the valuation allowance was increased by $16.9 million to a total valuation allowance of $17.6 million. At December 31, 1999, however, the Company determined that it was more likely than not that most of the deferred tax assets would be realized, based on commodity prices at year-end 1999, and the valuation allowance was decreased by $15.9 million.

Cumulative Effect of a Change in Accounting Principle

In December 2000, the staff of the Securities and Exchange Commission announced that commodity inventories should be carried at lower of cost or market rather than at market value. As a result, the Company changed its inventory valuation method to the lower of cost or market in the fourth quarter of 2000, retroactive to the beginning of the year. Accordingly, the Company recorded a non-cash, cumulative effect of a change in accounting principle to earnings, effective January 1, 2000, of $796,000 (net of the related income tax benefit of $537,000) to value product inventory at lower of cost or market. (See Note 2 to the Notes to Consolidated Financial Statements.)

Net Income (Loss)

Net income of $11.6 million and $31.4 million was reported in 2000 and 1999, respectively, as compared to a net loss of $94.3 million in 1998.

Capital Resources and Liquidity

Since its inception, the Company has grown and diversified its operations through a series of disciplined, low-cost acquisitions of oil and gas properties and the subsequent exploitation and development of these properties. The Company has complemented these efforts with divestitures of non-core assets and an opportunistic exploration program, which provides exposure to high-potential prospects. The funding of these activities has historically been provided by 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 $93.7 million, $24.0 million, and $35.8 million in 2000, 1999 and 1998, respectively. The Company invested $104.4 million, $125.9 million and $157.4 million in oil and gas properties in 2000, 1999 and 1998, respectively. Additionally, the Company spent $3.4 million, $10.2 million and $2.8 million on gas plant and other facilities in 2000, 1999 and 1998, respectively. In June 1999, the Company acquired oil and gas properties located onshore and offshore California for $61.4 million from Texaco, Inc. To purchase these assets, the Company used funds from a $100.0 million interest-bearing escrow account that was created with proceeds from the Company's January 1999 sale of its East Texas natural gas assets. Following the Texaco transaction, the $41.0 million remaining in the escrow account, which included $2.4 million of interest income, was used to repay a portion of outstanding bank debt in early July 1999.

The Company believes its working capital, cash flow from operations and available financing sources are sufficient to meet its obligations as they become due and to finance its exploration and development budget through 2001. The Company had an unused commitment under the Credit Facility of $225.0 million at December 31, 2000. At December 31, 2000, there were no maturities of long-term debt for the next five years.

Outlook

The Company's revenues, cash flows, results of operations and liquidity are highly dependent on oil and gas prices, as is its ability to acquire financing for its operations. Approximately 86% of the Company's production and 76% of the Company's revenues for 2000 were attributable to oil. Oil prices during 1998 and the first part of 1999 were very low compared to historical prices. As a result, the Company's 1998 revenues, earnings and cash flows were materially reduced compared to prior years, even though production levels increased during 1998. During 1999 and 2000, crude oil prices increased significantly. In late 2000, due to a natural gas shortage in California, natural gas prices increased significantly. Nuevo has a net long gas position in California - producing more natural gas than consumed in its thermal crude production. As gas prices escalated in late 2000, Nuevo began to exploit this gas position by diverting gas consumed in uneconomic cyclic steaming operations to gas sales. In January and February 2001, Nuevo sold an average of 19 MMcfd, or 44% of its total daily gas production, which has resulted in an increase in 2001 gas sales of 33%. This strategy will remain as long as gas prices support sales over thermal oil production.

In 1999, the Company's Board of Directors adopted a risk management policy, which was implemented by management and is periodically assessed by the Governance Committee of the Board. The Company's policy is designed to meet the following goals: (i) to assure the Company can generate sufficient operating cash flow to replace reserves that are produced and to (ii) assure compliance with restrictive debt covenants that would otherwise limit the Company's ability to incur additional debt. It is also the Company's policy that significant capital investments whose rates of return are sensitive to future oil and gas prices be protected from exposure to extreme price volatility.

The Company's 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, the Company will hedge as much of its production as is necessary to meet its policy goals for that period. Variations from this policy require Board approval. The risk management policy states that hedging activity that is speculative or otherwise unrelated to the Company's normal business activities is considered inappropriate. The Company recognizes the risks inherent in price management. In order to minimize such risk, the Company has instituted a set of controls addressing approval authority, trading limits and other control procedures. All hedging activity is the responsibility of the Chief Financial Officer. In addition, Internal Audit, which independently reports to the Audit Committee, reviews the Company's price management activity.

For 2001, the Company has entered into swap arrangements on 26,000 BOPD for the first quarter at an average WTI price of $19.52, for the second quarter on 25,000 BOPD at an average WTI price of $19.54, for the third quarter on 20,000 BOPD at an average WTI price of $21.22, and for the fourth quarter on 15,500 BOPD at an average WTI price of $22.95 per barrel. Subsequent to December 31, 2000, the Company entered into swaps on an additional 1,200 BOPD for the second quarter, bringing the total to 26,200 BOPD at an average price of $19.84 per barrel. On a physical volume basis, these hedges cover 47% of the Company's estimated 2001 oil production. At December 31, 2000, the market value of the swaps in place for 2001 was a loss of $35.1 million. A 10% increase in the underlying commodity prices would increase this loss by $19.7 million.

For 2002, the Company has entered into swap arrangements on 12,500 BOPD for the first quarter at an average WTI price of $25.91 per barrel. For the remainder of 2002, the Company purchased put options with a WTI strike price of $22.00 per barrel, on 19,000 BOPD for the second quarter, and on 14,000 BOPD for both the third and fourth quarters. At December 31, 2000, the market value of these hedge positions for 2002 is a gain of $8.3 million. A 10% increase in the underlying commodity prices would reduce this gain by $2.6 million.

All of these agreements expose the Company to counterparty credit risk to the extent that the counterparty is unable to meet its settlement commitments to the Company.

The Company set an original base level capital spending budget for 2001 of $181.0 million, with the potential for up to $24.0 million in additional capital spending, depending upon the level of drilling success. Due to the high gas prices in California, Nuevo deferred certain capital associated with its thermal operations and recently

adjusted its base capital spending budget to approximately $160.0 million, assuming gas prices remain at these high levels for the remainder of the year. Depending on the level of drilling success this year, capital spending could be increased by $18.0 million in 2001. Highlights of Nuevo's adjusted 2001 capital budget include the following:

- $123.0 million (77%) for exploitation projects, primarily earmarked for building on successful exploitation projects onshore California.
- $24.0 million (15%) for exploration, mainly for drilling eight to ten exploration wells in California and three to four exploration wells in Africa.
- $13.0 million (8%) for other capital projects.

Approximately 56% of Nuevo's $123.0 million exploitation budget in 2001 is allocated to onshore California exploitation projects, 29% to offshore California projects and 15% to international projects. The Company plans to drill a total of 73 exploitation wells in 2001. By comparison, Nuevo spent a total of $96.0 million company-wide for exploitation projects and drilled a total of 178 exploitation wells in 2000.

Onshore California, the Company's single largest exploitation project in 2001 is the continuing development of its Star Fee acreage in the Cymric Field. In 2001, this development will include drilling 7 Diatomite development wells and two follow-up wells to the highly successful Star Fee 701 well in this acreage. Nuevo also has budgeted to continue expanding the waterflood development and undertake other projects in its Brea Olinda Field and to continue successful drilling projects in the Belridge Field. Offshore California, Nuevo's capital spending is directed primarily at continuing development drilling in the Santa Clara Field and in the Pitas Point Field to further boost natural gas production. Internationally, the Company's exploitation budget is earmarked mainly for drilling additional horizontal wells to enhance the ongoing development in the Yombo Field offshore the Republic of Congo, West Africa.

Approximately 63% of Nuevo's $24.0 million exploration budget in 2001 will be used to drill nine exploratory wells in California and approximately 37% is allocated to drill three to four exploratory wells in West and North Africa.

The Company believes its working capital, cash provided by operating activities, project financing resources and the Credit Facility are sufficient to meet these capital commitments. The Company has not prepared a capital budget for annual periods after 2001.

Estimates of future net cash flows from proved reserves of oil, gas, condensate and natural gas liquids were made in accordance with SFAS No. 69, "Disclosures about Oil and Gas Producing Activities." (See Note 14 to the Notes to Consolidated Financial Statements). The estimates are based on realized prices at year-end 2000 of $19.51 per barrel of oil and $13.94 per MCF of gas. Significant changes can occur in these estimates based on prices currently in effect. The results of these disclosures should not be construed to represent the fair market value of the Company's 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. Natural gas prices were unusually high at December 31, 2000. Natural gas costs are a significant component of the Company's thermal operating costs in California. As such, the unusually high prices at year-end 2000 had an unfavorable effect on the Company's reserves for its thermal oil producing properties.

Inflation has not had a material impact on the Company and is not expected to have a material impact on the Company in the future.

New Accounting Pronouncements

In June 1998, the Financial Accounting Standards Board ("FASB") issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities". This statement, as amended by SFAS No. 137 and SFAS No. 138, establishes standards of accounting for and disclosures of derivative instruments and hedging activities. This

statement requires all derivative instruments to be carried on the balance sheet at fair value and is effective for the Company beginning January 1, 2001.

The Company adopted SFAS No. 133 on January 1, 2001. In accordance with the current transition provisions of SFAS 133, the Company will record a net-of-tax cumulative effect transition adjustment of $(16.0) million (net of related tax benefit of $10.8 million) in accumulated other comprehensive income to recognize the fair value of its derivatives designated as cash-flow hedging instruments at the date of adoption.

All of the Company's derivative instruments will be recognized on the balance sheet at their fair value. The Company currently uses swaps and options to hedge its exposure to material changes in the future price of crude oil.

Contingencies and Other Matters

The Company had been named as a defendant in Gloria Garcia Lopez and Husband, Hector S. Lopez, Individually, and as successors to Galo Land & Cattle Company v. Mobil Producing Texas & New Mexico, et al. in the 79th Judicial District Court of Brooks County, Texas. On June 9, 2000, the parties entered into a memorandum of settlement agreement, pursuant to which the lawsuit was dismissed, the defendants paid the plaintiffs $12.0 million and the lease agreement was amended. Nuevo's working interest in these properties is 20%, and its share of the settlement payment was approximately $2.4 million.

On September 22, 2000, the Company was named as a defendant in the lawsuit Thomas Wachtell et al. versus Nuevo Energy Company in the Superior Court of Los Angeles County, California. The plaintiffs, who own certain interests in the Point Pedernales properties, have asserted numerous causes of action including breach of contract, fraud and conspiracy in connection with the plaintiff's allegation that: (i) royalties have not been properly paid to them for production from the Point Pedernales field, (ii) payments have not been made to them related to production from the Sacate field, and, (iii) the Company has failed to recognize the plaintiff's interests in the Tranquillon Ridge project. The plaintiffs have not specified damages. The Company has not yet been required to file an answer, but believes the allegations are without merit and intends to vigorously contest these claims. Management does not believe that the outcome of this matter will have a material adverse impact on the Company's operating results, financial condition or liquidity.

The Company has been named as a defendant in certain other lawsuits incidental to its business. Management does not believe that the outcome of such litigation will have a material adverse impact on the Company's operating results or financial condition. However, these actions and claims in the aggregate seek substantial damages against the Company and are subject to the inherent uncertainties in any litigation. The Company is defending itself vigorously in all such matters.

In March 1999, the Company discovered that a non-officer employee had fraudulently authorized and diverted for personal use Company funds totaling $5.9 million, $1.6 million in 1999 and the remainder in 1998, that were intended for international exploration. The Board of Directors engaged a Certified Fraud Examiner to conduct an in-depth review of the fraudulent transactions. The investigation confirmed that only one employee was involved in the matter and that all misappropriated funds were identified. The Company has reviewed and, where appropriate, strengthened its internal control procedures. In August 2000, the Company recorded $1.5 million of other income for a partial reimbursement of these previously expensed funds, resulting from the negotiated settlement of a related legal claim.

In September 1997, there was a spill of crude oil into the Santa Barbara Channel from a pipeline that connects the Company's Point Pedernales field with shore-based processing facilities. The volume of the spill was estimated to be 163 barrels 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 insurance held by the Company, less the Company's deductibles of $120,000. The Company incurred clean-up and repair costs of $ 0.3 million, $0.5 million, and $2.4 million during 2000, 1999, and 1998, respectively. As of December 31, 2000, the Company had received insurance reimbursements of $4.1 million, with a remaining insurance receivable of $1.3 million. For amounts not covered by insurance, including the $120,000 deductible, the Company recorded lease operating expenses of $0.4 million and $0.5 million during 1999 and 1998,

respectively. No such expenses were recorded in 2000. Additionally, the Company has exposure to certain costs that are expected to be recoverable from insurance, including certain fines, penalties, and damages, for which the Company accrued $0.7 million as of December 31, 2000, as a receivable and payable. The Company also has exposure to costs that may not be recoverable from insurance, including certain fines, penalties, and damages. Such costs are not quantifiable at this time, but are not expected to be material to the Company's operating results, financial condition or liquidity.

The Company's 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 its foreign operations, the Company 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. The Company attempts to conduct its business and financial affairs so as to protect against political and economic risks applicable to operations in the various countries where it operates, but there can be no assurance that the Company will be successful in so protecting itself. A portion of the Company's investment in the Congo is insured through political risk insurance provided by 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. The Company has no deductible for this insurance.

In connection with their respective February 1995 acquisitions of two subsidiaries (each a "Congo subsidiary") owning interests in the Yombo field offshore Congo, the Company 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, the Company 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 the Company or CMS of its respective Congo subsidiary, (ii) either Congo subsidiary's sale of its interest in the Yombo field, (iii) the acquisition of the Company or CMS by another consolidated group or (iv) the failure of the Company or CMS's Congo subsidiary 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 US income tax purposes. The Company and CMS have agreed among themselves 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. The Company's potential direct liability could be as much as $42.5 million if a triggering event with respect to the Company occurs. Additionally, the Company believes that CMS's liability (for which the Company would be jointly liable with an indemnification right against CMS) could be as much as $61.0 million. The Company does not expect a triggering event to occur with respect to it or CMS and does not believe the agreement will have a material adverse effect upon the Company.

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 the Company's operations in the Congo, no assurances can be made that continued political unrest in West Africa will not have a material adverse effect on the Company and its operations in the Congo in the future.

In 1996, the previous Congo government requested that the convention governing the Marine 1 Exploitation Permit be converted to a Production Sharing Agreement ("PSA"). Preliminary discussions were held with the government in early 1997. Nuevo is under no obligation to convert to a PSA, and its existing convention is valid and protected by law. The Company's position is that any conversion to a PSA would have no detrimental impact to Nuevo, otherwise, Nuevo will not agree to any such conversion. In late 1997, a new government was established in the Congo. The new government has recently begun discussions with Nuevo and its partner

concerning the conversion to a PSA. Discussions with the new government are ongoing and, to date, no agreement has been reached concerning conversion to a PSA.

Contingent Payment and Price Sharing Agreements

In connection with the acquisition from Unocal in 1996 of the properties located in California, the Company is obligated to make a contingent payment for the years 1998 through 2004 if oil prices exceed thresholds set forth in the agreement with Unocal. Any contingent payment will be 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, 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). The Company accumulates credits to offset the contingent payment when prices are $.50 per Bbl or more below the minimum price. The Company computes this calculation annually and had accumulated $8.5 million in price credits as of December 31, 2000, which will be used to reduce future amounts owed under the contingent payment. There is no value attributable to this credit other than to offset future payments. At the end of 2004, if the Company still maintains a credit position with respect to this agreement, the credit will expire worthless. As of December 31, 2000, the Company had never been obligated to make a payment to Unocal under the terms of the agreement. However, a continuation of higher than normal oil price realizations is expected to trigger payments under this agreement beginning in March of 2002.

In connection with the acquisition of the Congo properties in 1995, the Company entered into a price sharing agreement with the seller. There is no termination date associated with this agreement. 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, then the Company is obligated to pay the seller 50% of the difference between the benchmark price and the actual price received, for all the barrels associated with this acquisition. The benchmark price for 1999 was $14.79 per Bbl, and the benchmark price for 2000 was $15.19 per Bbl. The benchmark price increases each year, based on the increase in the Consumer Price Index. For 2000, the effect of this agreement was that Nuevo only owned upside above $15.19 per Bbl on approximately 56% of its Congo production. In 2000, the Company was obligated to pay the seller $5.4 million pursuant to this price sharing agreement. This obligation was accounted for as a reduction in oil revenues. No such payments were due in 1998 or 1999.

The Company 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. The Company is entitled to all revenue proceeds up to $9.00 per Bbl, with the excess revenue over $9.00 per Bbl, if any, shared among the Company and the original owners from whom Torch acquired its interest. Amounts below $9.00 per Bbl are owned by the Company and the other working interest owners based on their respective ownership interests. For 2000, the effect of this agreement is that Nuevo was entitled to receive the pricing upside above $9.00 per Bbl on approximately 34% of the gross Point Pedernales production. Effective January 1, 2001, the Company will be entitled to receive the pricing upside above $9.00 per Bbl on approximately 70% of the gross Point Pedernales production. As of December 31, 2000, the Company had $581,000 accrued as its obligation under this agreement. As of December 31, 1999, the Company had $5.1 million accrued as its obligation under this agreement, which was paid in the first quarter of 2000.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to market risk, including adverse changes in commodity prices and interest rates.

Commodity Price Risk - The Company produces and sells crude oil, natural gas and natural gas liquids. As a result, the Company's operating results can be significantly affected by fluctuations in commodity prices caused by changing market forces. The Company reduces its exposure to price volatility by hedging its production through swaps, options and other commodity derivative instruments. In a typical swap transaction, the Company 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, the Company is required to pay the counterparty the difference. In a typical option contract, the Company purchases 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, the Company is not entitled to a payment. The Company uses 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 the Company to counterparty credit risk to the extent that the counterparty is unable to meet its settlement commitments to the Company.

The Company follows formal policies regarding the management of oil price risk to ensure the Company's ability to optimally manage its portfolio of investment opportunities. To accomplish this, the policy requires that derivative financial instruments must be entered into at least 18 months in advance of the effective period. For 2001, the Company has entered into swap arrangements on 26,000 BOPD for the first quarter at an average WTI price of $19.52, for the second quarter on 25,000 BOPD at an average WTI price of $19.54, for the third quarter on 20,000 BOPD at an average WTI price of $21.22, and for the fourth quarter on 15,500 BOPD at an average WTI price of $22.95 per barrel. Subsequent to December 31, 2000, the Company entered into swaps on an additional 1,200 BOPD for the second quarter, bringing the total to 26,200 BOPD at an average price of $19.84 per barrel. On a physical volume basis, these hedges cover 47% of the Company's estimated 2001 oil production. At December 31, 2000, the market value of the swaps in place for 2001 was a loss of $35.1 million. A 10% increase in the underlying commodity prices would increase this loss by $19.7 million.

For 2002, the Company has entered into swap arrangements on 12,500 BOPD for the first quarter at an average WTI price of $25.91 per barrel. For the remainder of 2002, the Company purchased put options with a WTI strike price of $22.00 per barrel, on 19,000 BOPD for the second quarter, and on 14,000 BOPD for both the third and fourth quarters. At December 31, 2000, the market value of these hedge positions for 2002 is a gain of $8.3 million. A 10% increase in the underlying commodity prices would reduce this gain by $2.6 million.

Interest Rate Risk - The Company may enter into financial instruments such as interest rate swaps to manage the impact of changes in interest rates. The Company's exposure to changes in interest rates primarily results from its short-term and long-term debt with both fixed and floating interest rates. The following table presents principal amounts (stated in thousands) and the related average interest rates by year of maturity for the Company's debt obligations at December 31, 2000:

	2001	2002	2003	2004	Thereafter	Total	Fair Value Liabili
Long-term debt:							
Variable rate	--	--	--	--	--	--	
Average interest rate	--	--	--	--	--	--	
Fixed rate	--	--	--	--	$409,727	$409,727	$412,8
Average interest rate	--	--	--	--	9.45%	9.45%	

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NUEVO ENERGY COMPANY

Item 8. Financial Statements and Supplementary Data

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Consolidated Balance Sheets as of December 31, 2000
and 1999...

Consolidated Statements of Operations for the Years Ended
December 31, 2000, 1999 and 1998...

Consolidated Statements of Changes in Stockholders'
Equity for the Years Ended December 31, 2000,
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Consolidated Statements of Cash Flows for the Years Ended
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Notes to Consolidated Financial Statements...

NUEVO ENERGY COMPANY

INDEPENDENT AUDITORS' REPORT

The Board of Directors
Nuevo Energy Company:

We have audited the accompanying consolidated balance sheets of Nuevo Energy Company and subsidiaries as of December 31, 2000 and 1999, and the related consolidated statements of operations, changes in stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 2000. 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, 2000 and 1999, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States of America.

As 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.

KPMG LLP

Houston, Texas
February 8, 2001

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NUEVO ENERGY COMPANY

CONSOLIDATED BALANCE SHEETS

(AMOUNTS IN THOUSANDS, EXCEPT SHARE DATA)

	2
ASSETS	
CURRENT ASSETS:	
Cash and cash equivalents	$
Accounts receivable	
Product inventory	
Prepaid expenses and other	
Total current assets	1
PROPERTY AND EQUIPMENT, at cost:	
Land	
Oil and gas properties (successful efforts method)	1,1
Gas plant facilities	
Other facilities	
	1,1
Accumulated depreciation, depletion and amortization	(4
	6
DEFERRED TAX ASSETS, net	
OTHER ASSETS	
	$ 8
LIABILITIES AND STOCKHOLDERS' EQUITY	
CURRENT LIABILITIES:	
Accounts payable	$

Accrued interest..	
Accrued drilling costs..	
Accrued lease operating costs...	
Other accrued liabilities...	
Current maturities of long-term debt..	
Total current liabilities...	
LONG-TERM DEBT, net of current maturities...	4
OTHER LONG-TERM LIABILITIES...	
COMPANY-OBLIGATED MANDATORILY REDEEMABLE CONVERTIBLE PREFERRED SECURITIES OF NUEVO FINANCING I...	1
CONTINGENCIES (Note 11)	
STOCKHOLDERS' EQUITY:	
Preferred stock, $1.00 par value, 10,000,000 shares authorized; 7% Cumulative Convertible Preferred Stock, none issued and outstanding at December 31, 2000 and 1999..	
Common stock, $0.01 par value, 50,000,000 shares authorized, 20,620,296 and 20,437,371 shares issued and 16,632,318 and 17,931,393 shares outstanding at December 31, 2000 and 1999, respectively.....................................	
Additional paid-in capital..	3
Treasury stock, at cost, 3,813,074 and 2,430,074 shares, at December 31, 2000 and 1999, respectively..	(
Stock held by benefit trust, 174,904 and 75,904 shares, at December 31, 2000 and 1999, respectively..	
Deferred stock compensation...	
Accumulated deficit...	(
Total stockholders' equity..	2
	$ 8

See Notes to Consolidated Financial Statements.

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NUEVO ENERGY COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS

(AMOUNTS IN THOUSANDS, EXCEPT PER SHARE DATA)

	Year
	2000
REVENUES:	
Oil and gas revenues..	$331,655
Gain on sale of assets, net.....................................	657
Interest and other income.......................................	4,293
	336,605
COSTS AND EXPENSES:	
Lease operating expenses..	156,476

Exploration costs	9,774
Revision of impairment on assets held for sale	--
Provision for impairment of oil and gas properties	--
General and administrative expenses	32,974
Depreciation, depletion and amortization	67,370
Interest expense, net	37,472
Dividends on Guaranteed Preferred Beneficial Interests in Company's Convertible Debentures (TECONS)	6,613
Other expense	5,103
	315,782
Income (loss) before income taxes and cumulative effect	20,823
Income tax (expense) benefit	(8,392)
Income (loss) before cumulative effect	12,431
Cumulative effect of a change in accounting principle, net of income tax benefit of $537	(796)
Net income (loss)	$ 11,635
Earnings (loss) per Common share -- Basic:	
Income (loss) before cumulative effect	$ 0.71
Cumulative effect of a change in accounting principle, net of income tax benefit	(0.04)
Net income (loss)	$ 0.67
Weighted average Common shares outstanding	17,447
Earnings (loss) per Common share -- Diluted:	
Income (loss) before cumulative effect	$ 0.68
Cumulative effect of a change in accounting principle, net of income tax benefit	(0.04)
Net income (loss)	$ 0.64
Weighted average Common and dilutive potential Common shares outstanding	17,941

See Notes to Consolidated Financial Statements.

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NUEVO ENERGY COMPANY

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

(Amounts in Thousands)

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Treasury Stock	Stock held by Benefit Trust	Deferred Sto Compensatio
January 1, 1998........	19,696	$202	$354,296	$(19,929)	$(1,244)	$ --
Exercise of stock options and related tax benefit...........	70	1	1,304	--	--	
Stock acquired by benefit trust.........	--	--	--	488	(1,341)	
Withdrawal from benefit trust.........	18	--	--	--	853	
Sale of Treasury shares	3	--	--	106	--	
Net loss...............	--	--	--	--	--	
December 31, 1998......	19,787	203	355,600	(19,335)	(1,732)	
Exercise of stock options and related tax benefit...........	129	1	1,810	--	--	
Stock acquired by benefit trust.........	--	--	--	1,850	(1,850)	
Issuance of warrants and other.............	--	--	120	--	--	
Withdrawal from benefit trust.........	14	--	--	--	398	
Purchase of Treasury shares................	(1,999)	--	--	(32,120)	--	
Deferred stock compensation..........	--	--	325	--	--	(2
Net income.............	--	--	--	--	--	
December 31, 1999......	17,931	204	357,855	(49,605)	(3,184)	(2
Exercise of stock options and related tax benefit...........	183	2	3,200	--	--	
Stock acquired by benefit trust.........	--	--	--	462	(462)	
Purchase of Treasury shares................	(1,482)	--	--	(25,560)	--	
Deferred stock compensation..........	--	--	588	--	--	(3
Net income.............	--	--	--	--	--	
December 31, 2000......	16,632	$206	$361,643	$(74,703)	$(3,646)	$(6

See Notes to Consolidated Financial Statements.

NUEVO ENERGY COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(AMOUNTS IN THOUSANDS)

	Year E
	2000
CASH FLOWS FROM OPERATING ACTIVITIES:	
Net income (loss)...	$ 11,635
Adjustments to reconcile net income (loss) to net cash provided by operating activities:	
Cumulative effect of a change in accounting principle, net of income tax benefit....................................	796
Depreciation, depletion and amortization..................	67,370
Dry hole costs...	2,503
Amortization of debt financing costs......................	1,983
Amortization of deferred revenue..........................	--
Revision of impairment on assets held for sale............	--
Provision for impairment of oil and gas properties.........	--
Gain on sale of assets, net..............................	(657)
Deferred taxes...	8,763
(Depreciation) appreciation of deferred compensation liability...	(234)
Debt modification costs..................................	--
Other..	203
	92,362
Changes in assets and liabilities:	
Accounts receivable......................................	(26,266)
Accounts payable...	5,403
Accrued liabilities......................................	25,490
Other..	(3,287)
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES.............	93,702
CASH FLOWS FROM INVESTING ACTIVITIES:	
Additions to oil and gas properties..........................	(104,420)
Proceeds from sales of properties............................	3,083
Additions to gas plant and other facilities..................	(3,388)
NET CASH FLOWS (USED IN) PROVIDED BY INVESTING ACTIVITIES....	(104,725)
CASH FLOWS FROM FINANCING ACTIVITIES:	
Proceeds from borrowings.....................................	197,100
Debt issuance and modification costs.........................	(5,186)
Payments of long-term debt...................................	(128,873)
Proceeds from exercise of stock options......................	2,701
Proceeds from sale of treasury stock.........................	--
Purchase of treasury shares..................................	(25,560)
NET CASH FLOWS PROVIDED BY (USED IN) FINANCING ACTIVITIES.....	40,182
Net increase (decrease) in cash and cash equivalents............	29,159
Cash and cash equivalents at beginning of year..................	10,288
Cash and cash equivalents at end of year........................	$ 39,447

See Notes to Consolidated Financial Statements.

NUEVO ENERGY COMPANY

NOTES TO 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 such 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.

The Company is primarily engaged in the exploration for, and the acquisition, exploitation, development and production of crude oil and natural gas. The Company's principal oil and gas properties are located domestically onshore and offshore California and the onshore Gulf Coast region; and internationally offshore West Africa.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The consolidated financial statements include the accounts of Nuevo and its majority and wholly-owned subsidiaries. The Company's 48.5% general partner interest in Richfield Gas Storage Partnership was pro rata consolidated through February 1998, at which time the Company's interest was sold. The consolidated financial statements also include Bright Star Gathering, Inc., which was 80% owned by the Company until it was sold in July 1998. All significant intercompany accounts and transactions have been eliminated in consolidation.

Oil and Gas Properties

The Company utilizes the successful efforts method of accounting for its investments in oil and gas properties. Under successful efforts, 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, gain or loss is recognized, taking into consideration any recorded impairment. When a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained.

Unproved leasehold costs are capitalized pending the results of exploration efforts. 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. An impairment of unproved leasehold costs of $8.1 million was recognized as of December 31, 1998. No such impairment was recognized for the years ended December 31, 2000 or 1999. Exploration costs, including geological and geophysical expenses, exploratory dry holes and delay rentals, are charged to expense as incurred.

Costs of successful wells, development dry holes and proved leases are capitalized and depleted on a unit-of-production basis over the life of the remaining proved reserves. Capitalized drilling costs are depleted on a unit-of-production basis over the life of the remaining proved developed reserves. Total estimated costs of $82.1 million (net of salvage value) for future dismantlement, abandonment and site remediation are computed by the Company and an independent consultant and are included when calculating depreciation and depletion using the unit-of-production method. At December 31, 2000, the Company had recorded $60.8 million as a component of accumulated depreciation, depletion and amortization.

In accordance with SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of", the Company reviews its 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. 121 requires an impairment loss be recognized when the carrying amount of an asset exceeds the sum of the undiscounted estimated future cash flows. In this circumstance, the Company recognizes 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 present value of expected future net cash flows from proved reserves, utilizing a risk-adjusted rate of return.

During 1998, the Company recorded a fair value impairment totaling $60.8 million on its East Coalinga, Las Cienegas, Beta, Point Pedernales and South Mountain fields and certain other insignificant oil and gas properties due to the significant, sustained decline in domestic oil prices during the year from an average Company realized price of $14.86 per barrel for 1997 to an average realized price of $9.25 per barrel in 1998. No such impairment was recognized during 2000 or 1999.

During 1999 and 1998, 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 the Company's weighted average cost of funds used to finance expenditures. No such costs were capitalized in 2000.

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

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 the Company's commitment to a formal plan of action.

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. The Company reviews these assets for impairment whenever events or changes in circumstances indicate that their carrying amounts may not be recoverable.

Comprehensive Income

Comprehensive income includes net income and all changes in other comprehensive income including, among other things, foreign currency translation adjustments, and unrealized gains and losses on investments in debt and equity securities that are classified as available-for-sale. There are no differences between comprehensive income (loss) and net income (loss) for the periods presented.

Recognition of Crude Oil and Natural Gas Revenue

The Company uses the entitlement method for recording sales of crude oil and natural gas from producing wells. Under the entitlement method, revenue is recorded based on the Company's net revenue interest in production. Deliveries of crude oil and natural gas in excess of the Company's 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. The Company's imbalance position was not significant in terms of units or value at December 31, 2000 and 1999.

Derivative Financial Instruments

The Company utilizes derivative financial instruments to reduce its exposure to decreases in the market prices of crude oil and natural gas. Commodity derivatives utilized as hedges include futures, swap and option contracts, which are used to hedge crude oil and natural gas prices. Basis swaps are sometimes used to hedge the basis differential between the derivative financial instrument index price and the commodity field price. In order to qualify as a hedge, price movements in the underlying commodity derivative must be highly correlated with the hedged commodity. Settlement of gains and losses on price swap contracts are realized monthly, generally based upon the difference between the contract price and the average closing New York Mercantile Exchange ("NYMEX") price and are reported as a component of oil and gas revenues and operating cash flows in the period realized.

Gains and losses on option and futures contracts that qualify as a hedge of firmly committed or anticipated purchases and sales of oil and gas commodities are deferred on the balance sheet and recognized in income and operating cash flows when the related hedged transaction occurs. Premiums paid on option contracts are deferred in other assets and amortized into oil and gas revenues over the terms of the respective option contracts. Gains or losses attributable to the termination of a derivative financial instrument are deferred on the balance sheet and recognized in revenue when the hedged crude oil and natural gas is sold. There were no such deferred gains or losses at December 31, 2000 or 1999. Gains or losses on derivative financial instruments that do not qualify as a hedge are recognized in income currently.

As a result of hedging transactions, oil and gas revenues were reduced by $117.7 million and $44.9 million in 2000 and 1999, respectively, and increased by $0.6 million in 1998.

New Accounting Pronouncements

In June 1998, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities". This statement, as amended by SFAS No. 137 and SFAS No. 138, establishes standards of accounting for and disclosures of derivative instruments and hedging activities. This statement requires all derivative instruments to be carried on the balance sheet at fair value and is effective for the Company beginning January 1, 2001.

The Company adopted SFAS No. 133 on January 1, 2001. In accordance with the current transition provisions of SFAS 133, the Company will record a net-of-tax cumulative-effect transition adjustment of $(16.0) million (net of related tax benefit of $10.8 million)(unaudited) in accumulated other comprehensive income to recognize the fair value of its derivatives designated as cash-flow hedging instruments at the date of adoption.

All of the Company's derivative instruments will be recognized on the balance sheet at their fair value. The Company currently uses swaps and options to hedge its exposure to material changes in the future price of crude oil.

Earnings per Share ("EPS")

Basic EPS is computed by dividing income available to common stockholders by the weighted-average number of common shares outstanding for the period. Diluted EPS reflects the potential dilution that could occur if securities or other contracts to issue Common Stock were exercised or converted into Common Stock or resulted in the issuance of Common Stock that then shared in the earnings of the entity. For the year ended December 31, 2000 and 1999, the Company's potentially dilutive securities included dilutive stock options. For the year ended December 31, 1998, the Company did not have any potentially dilutive securities, as a net loss was incurred during this period. Potential dilution may also occur in future periods due to the Company-Obligated Mandatorily Redeemable Convertible Preferred Securities of Nuevo Financing I ("TECONS").

Stock-Based Compensation

The Company applies the intrinsic value method for accounting for stock and stock-based compensation described by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees". Had the Company applied the fair value method described by SFAS No. 123, "Accounting for Stock-Based Compensation", it would have incurred compensation expense for stock-based compensation in 2000, 1999 and 1998. (See Note 6 for the SFAS No. 123 pro forma effects on income and earnings per share.)

Income Taxes

Deferred 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, the Company considers all highly liquid money market instruments with an original maturity of three months or less to be cash equivalents. Interest paid in cash, net of amounts capitalized, for 2000, 1999 and 1998 was $32.1 million, $33.5 million and $31.6 million, respectively. Net amounts (refunded) paid in cash for income taxes for 2000, 1999 and 1998 were ($486,000), $2,250,000 and $1,332,000, respectively.

Cumulative Effect of a Change in Accounting Principle

Historically, the Company 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 the Company 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 lower of cost or market rather than at market value. As a result, the Company changed its inventory valuation method to the lower of cost or market in the fourth quarter of 2000, retroactive to the beginning of the year. Accordingly, the Company recorded a non-cash, cumulative effect of a change in accounting principle to earnings, effective January 1, 2000, of $796,000 (net of the related income tax benefit of $537,000) to value product inventory at lower of cost or market. Quarterly results for 2000 were restated to reflect this change in accounting.

Had the Company valued its product inventory at lower of cost or market prior to 2000, net income (loss) would have been $30.6 million and $(94.3) million for the years ended December 31, 1999 and 1998, respectively.

Use of Estimates

In order to prepare these financial statements in conformity with accounting principles generally accepted in the United States, management of the Company 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.

Reclassifications

Certain reclassifications of prior period amounts have been made to conform to the current presentation.

3. ACQUISITIONS

In June 1999, the Company acquired working interests in oil and gas properties located onshore and offshore California for $61.4 million from Texaco Inc. The working interests in the acquired properties range

from an additional 25% interest in properties already owned and operated by the Company to 100%. To purchase these assets, the Company used funds from a $100.0 million interest-bearing escrow account that provided "like-kind exchange" tax treatment for the purchase of domestic oil and gas producing properties. The escrow account was created with proceeds from the Company's January 1999 sale of its East Texas natural gas assets (see discussion in Note 4). Following the Texaco transaction, the $41.0 million remaining in the escrow account, which included $2.4 million of interest income, was used to repay a portion of outstanding bank debt in early July 1999. The acquired properties had estimated net proved reserves at June 30, 1999, of 33.7 MMBOE (unaudited) and are either additional interests in the Company's existing properties or are located near its existing properties. The acquisition included interests in Cymric, East Coalinga, Dos Cuadras, Buena Vista Hills and other fields the Company operates.

In April 1998, the Company acquired an additional working interest in the Marine 1 Permit in the Republic of Congo, West Africa ("Congo") for $7.8 million. This acquisition increased the Company's net working interest in the Congo from 43.75% to 50.0%.

4. DIVESTITURES

In May 2000, the Company sold its working interest in the Las Cienegas field in California for proceeds of approximately $4.6 million. The Company reclassified these assets to assets held for sale during the third quarter of 1999, at which time it discontinued depleting and depreciating these assets. No impairment charge was recorded upon reclassification to assets held for sale. In connection with this sale, the Company unwound hedges of 2,800 BOPD for the period May 2000 through December 2000 and recorded an adjusted net gain on sale of approximately $923,000. Also, the Company sold certain of its non-core assets during 2000, recognizing a net loss of approximately $266,000.

On December 31, 1999, the Company completed the sale of its working interests (ranging from 8% to 100%) in 13 onshore fields and a gas processing plant located in Ventura County, California, to Vintage Petroleum, Inc. The effective date of the sale was September 1, 1999. Accordingly, the Company reclassified these properties to assets held for sale and discontinued depleting and depreciating these assets during the third quarter of 1999. Revenues less costs for the period September 1, 1999, through December 31, 1999, and other adjustments resulted in an adjusted sales price of $29.6 million at closing on December 31, 1999. A portion of the proceeds, $4.5 million, was deposited in escrow to address possible remediation issues. The funds will remain in escrow until the Los Angeles Regional Water Quality Control Board approves completion of the remediation work. All or any portion of the funds not used in remediation shall be delivered to the Company. As of December 31, 2000, the balance in the escrow account remained at $4.5 million. The remainder of the proceeds from the sale were used to repay a portion of the Company's outstanding bank debt. The assets accounted for approximately 3% of Nuevo's September 1, 1999 estimated proved reserves. Production from the properties for the year ended December 31, 1999, averaged 2,510 barrels of oil equivalent per day. The Company recorded a gain of $5.3 million on the sale of these properties.

On January 6, 1999, the Company completed the sale of its East Texas natural gas assets to an affiliate of Samson Resources Company for an adjusted sales price of approximately $191.0 million. Of the proceeds, $100.0 million was set aside to fund an escrow account, as discussed in Note 3. The remainder of the proceeds were used to repay outstanding senior bank debt. The Company realized an $80.2 million adjusted pre-tax gain on the sale of the East Texas natural gas assets resulting in the realization of $14.6 million of the Company's deferred tax asset. A $5.2 million gain on settled hedge transactions was realized in connection with the closing of this sale in 1999. The effective date of the sale was July 1, 1998. The Company reclassified these assets to assets held for sale and discontinued depleting these assets during the third quarter of 1998. Estimated net proved reserves associated with these properties totaled approximately 329.0 Bcfe (unaudited) at January 1, 1999.

During the third quarter of 1998, the Company sold its 100% working interest in the Sansinena field in California for proceeds of $4.2 million, and recorded a gain on the sale of $4.1 million. During the first quarter of 1998, the Company sold its 100% working interest in the Coke field in Chapel Hill, Texas for proceeds of $1.9 million, and recorded a $1.7 million gain on this sale.

5. OUTSOURCING SERVICES

Torch Energy Advisors Incorporated ("Torch"), the Company's outside service provider, is primarily in the business of providing management and advisory services relating to oil and gas assets for institutional and public investors and maintains a large technical, operating, accounting and administrative staff.

In early 1999, Nuevo signed new outsourcing agreements with Torch and its subsidiaries, effective January 1, 1999, to provide the following services: (i) oil and gas administration (accounting, information technology and land administration); (ii) human resources; (iii) corporate administration (legal, graphics, support, and corporate insurance); (iv) crude oil marketing; (v) natural gas marketing; (vi) land leasing, and (vii) field operations. Each of the new agreements is stand alone, with different terms ranging from one to four years. In addition, the Company executed a Master Services Agreement with Torch, which contains the overall terms and conditions governing each individual service agreement. Several functions that were previously outsourced, such as mergers and acquisitions and internal audit, were brought in-house during 1999. In 2000, Nuevo extended the oil and gas administration agreement, entered into a new field operations agreement and terminated the corporate administration and land leasing agreements. As a result, Nuevo reduced both the staffing requirements and cost structure under the Torch agreements and brought certain professional and other positions in-house.

The major components of compensation under each Torch agreement are as follows: (i) under the oil and gas administration agreement, Nuevo is charged a monthly base fee which is adjusted upward or downward to reflect the current number and type of properties for which services are provided; (ii) under the human resources agreement, Nuevo is charged a monthly base fee which is adjusted upward or downward to reflect changes in the total number of its employees; (iii) both the crude oil and natural gas marketing agreements obligate Nuevo to pay a base charge and a variable charge based on the volume of crude oil and natural gas sold or marketed; and (iv) under the field operation agreement, Nuevo is charged a base fee and pays performance based incentive fees related to, among other matters, regulatory compliance and cost control.

Prior to January 1, 1999, the Company's outsourcing services were governed by an agreement with Torch (the "Torch Agreement") whereby Torch administered certain business activities of the Company for a monthly fee. The Torch Agreement required Torch to administer the business activities of the Company for a monthly fee equal to the sum of one-twelfth of 2% on the first $250 million of assets and one-twelfth of 1% on assets in excess of $250 million, excluding certain gas plant facilities and cash, plus 2% of monthly operating cash flows (as defined) during the period in which the services were rendered. In addition, the Torch Agreement contained a provision whereby 20% of the overhead fees on Torch operated properties were credited against the monthly fee paid to Torch, as well as a provision whereby the monthly fee was credited for one-twelfth of $900,000. For the years ended December 31, 2000, 1999 and 1998, outsourcing fees paid to Torch amounted to $13.7 million, $14.1 million and $14.5 million, respectively.

A subsidiary of Torch markets oil, natural gas and natural gas liquids from certain oil and gas properties and gas plants in which the Company owns an interest. In 2000, 1999 and 1998, such marketing fees were $1.8 million, $1.2 million and $2.0 million, respectively.

Torch operates certain oil and gas interests owned by the Company. The Company is charged, on the same basis as other third parties, for all customary expenses and cost reimbursements associated with these activities. Operator's fees charged for these activities for the years ended December 31, 2000, 1999 and 1998, were $21.8 million, $25.1 million and $20.5 million, respectively.

6. STOCKHOLDERS' EQUITY

Common and Preferred Stock

The Certificate of Incorporation of the Company authorizes the issuance of up to 50,000,000 shares of Common Stock and 10,000,000 shares of Preferred Stock, the terms, preferences, rights and restrictions of which are established by the Board of Directors of the Company. 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 the Company's loan agreements limit the amount of dividends that may be declared. Under the terms of the most restrictive covenant in its indenture for the 9 1/2% Senior Subordinated Notes due 2008 described in Note 8, the Company and its restricted subsidiaries had $20.5 million available for the payment of dividends and share repurchases at December 31, 2000. The Company has not paid dividends on its Common Stock and does 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 1999 and 1998, weighted average shares held by benefit trust of 64,000 and 42,000, respectively, are not included in the calculation of diluted loss per share due to their anti-dilutive effect. In 1998, weighted average potential dilutive common shares of 331,000 are not included in the calculation of diluted loss per share due to their anti-dilutive effect. The Company's reconciliation is as follows (amounts in thousands):

	For the Year Ended December 31,				
	2000		1999		
	Income	Shares	Income	Shares	Loss
Earnings (loss) before cumulative effect per Common share -- Basic	$12,431	17,447	$31,442	19,353	$(94,
Effect of dilutive securities:					
Stock options	--	335	--	154	
Shares held by Benefit Trust	(152)	159	--	--	
Earnings (loss) before cumulative effect per Common share -- Diluted	$12,279	17,941	$31,442	19,507	$(94,

Treasury Stock Repurchases

Since December 1997, the Board of Directors of the Company authorized the open market repurchase of up to 4,616,600 shares of outstanding Common Stock at times and at prices deemed appropriate by management. During 2000, the Company repurchased 1,482,000 shares of its Common Stock in open market transactions at an average purchase price, including commissions, of $16.67 per share. During 1999, the Company repurchased 1,999,100 shares of its Common Stock in open market transactions at an average purchase price, including commissions, of $16.50 per share. No Common Stock was repurchased during 1998. As of March 22, 2001, the Company had repurchased 3,608,900 shares, on a cumulative basis, at an average purchase price of $16.56 per share, including commissions, under the current share repurchase program.

Shareholder Rights Plan

In March 1997, the Company adopted a Shareholder Rights Plan to protect the Company's 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 the prior consent of the Company, or the Company is acquired in a merger or other business combination, or 50% or more of its 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. The Company 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 the Board of Directors of the Company.

On January 10, 2000, the Company amended the Shareholder Rights Plan to provide that if the Company receives and consummates 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

During July 1997, the Board of Directors of the Company adopted a plan to encourage senior executives to personally invest in the stock of the Company, 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 Common Stock of the Company at a discount to market prices or make other investments at the employee's discretion. Stock acquired at a discount will be held in a benefit trust and will be restricted for a two-year period. The stock held in the benefit trust (174,904 shares, 75,904 shares and 47,759 shares at December 31, 2000, 1999 and 1998, respectively) is accounted for as a liability of the Company and is marked-to-market, with any necessary adjustment to general and administrative expense. The Company recorded a net benefit of $0.1 million in 2000 related to deferred compensation, total expenses of $1.7 million in 1999, and a net benefit of $0.6 million in 1998. The Plan does not permit investment in a diversified equity portfolio until and unless targeted levels of Common Stock ownership in the Company are achieved and maintained. 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 can be settled by the Company in cash or Common Stock, at the option of the employee. The Plan applies to certain highly compensated employees and all executives at a level of Vice-President and above.

Director Compensation

In May 1999, the Compensation Committee of the Board of Directors implemented changes to the compensation of the Company's non-employee directors. Non-employee directors may elect to receive all or part of the annual cash retainer of $30,000 in restricted shares of the Company's 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. Each non-employee director also receives a semi-annual grant of 1,750 ten-year options to purchase the Company's Common Stock at the market price of the stock on the date of the grant. Non-employee directors also receive a semi-annual grant of 1,250 restricted shares of the Company's 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.

Stock Incentive Plan

In 1990, the Company established its 1990 Stock Option Plan with respect to its Common Stock; 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"). The purpose of the Stock Incentive Plans is to provide directors and key employees of the Company performance incentives and to provide a means of encouraging stock ownership in the Company by such persons.

The total maximum number of shares subject to options under the Stock Incentive Plans is 5,000,000 shares. Options are granted under the Stock Incentive Plans on the basis of the optionee's contribution to the Company. 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. The Company's 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 granted are exercisable, in full, six months following the date of the grant. Options vest over a three-year period for officers of the Company who have not met the ownership target set out under the Targeted Stock Ownership Plan.

A summary of activity in the stock option plans during the three years ended 1999 is set forth below:

	Options	Weig Ave Exercis
Outstanding at January 1, 1998	2,089,463	
Granted	1,124,800 *	
Exercised	(70,925)	
Canceled	(466,975)*	
Outstanding at December 31, 1998	2,676,363	
Granted	481,225	
Exercised	(128,909)	
Canceled	(411,500)	
Outstanding at December 31, 1999	2,617,179	
Granted	419,189	
Exercised	(182,925)	
Canceled	(80,525)	
Outstanding at December 31, 2000	2,772,918	

* Reflects the cancellation and re-issuance of 401,850 non-executive employee stock options on December 14, 1998.

The Company had options exercisable of 2,361,979 (weighted average exercise price of $23.04), 2,202,454 (weighted average exercise price of $24.00), and 1,756,263 (weighted average exercise price of $29.44) at December 31, 2000, 1999 and 1998, respectively. Detail of stock options outstanding and options exercisable at December 31, 2000 follows:

Range of Exercise Prices	Outstanding Number	Outstanding Weighted-Average Remaining Life (Years)	Outstanding Weighted-Average Exercise Price	Numbe
$10.31 to $15.06..................	760,013	8.36	$12.21	57
$15.50 to $19.63..................	982,205	7.14	$16.67	75
$20.38 to $29.88..................	430,700	6.10	$23.44	43
$34.00 to $47.88..................	600,000	6.66	$41.84	60
Total...........................	2,772,918			2,36

The weighted-average fair value of options granted during 2000, 1999 and 1998, was $10.87, $11.38 and $7.55, respectively. 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 112% in 2000, 55.7% in 1999 and 50.9% in 1998; risk free interest of 5% in 2000, 6% in 1999 and 5% in 1998, and average expected option lives of three years in 2000 and five years in 1999 and 1998. Had compensation expense for stock-based compensation been determined based on the fair value at the date of grant, the Company's net income, earnings available to common stockholders and earnings per share would have been reduced to the pro forma amounts indicated below (amounts in thousands, except per share data):

		Year En 2000
Net income (loss)......................................	As reported	$11,635
	Pro forma	$ 6,740
Earnings (loss) per Common share -- Basic................	As reported	$ 0.67
	Pro forma	$ 0.39
Earnings (loss) per Common share -- Diluted.............	As reported	$ 0.64
	Pro forma	$ 0.38

7. 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 2,300,000 Term Convertible Securities, Series A, ("TECONS") on behalf of the Trust. The price to the public of the TECONS was $50.00 per TECONS. Distributions on the TECONS 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 .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 Nuevo 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.

8. LONG-TERM DEBT

Long-term debt is comprised of the following at December 31, 2000 and 1999 (amounts in thousands):

	2000
9 3/8% Senior Subordinated Notes due 2010 (a)	$150,000
9 1/2 % Senior Subordinated Notes due 2008 (b)	257,310
9 1/2 % Senior Subordinated Notes due 2006 (b) (c)	2,417
OPIC credit facility (at 5.8% at December 31, 1999, plus a guaranty fee of 2.75%) (d)	--
Bank credit facility (at 7.13% at December 31, 1999) (e)	--
Total debt	409,727
Less current maturities	--
Long-term debt	$409,727

(a) On September 26, 2000, the Company issued $150.0 million of 9 3/8% Senior Subordinated Notes due September 15, 2010 ("9 3/8% Notes"). Interest on the 9 3/8% Notes accrues at the rate of 9 3/8% per annum and is payable semi-annually in arrears on April 1 and October 1. The 9 3/8% Notes are redeemable, in whole or in part, at the option of the Company, on or after October 1, 2005, under certain conditions. The Company is not required to make mandatory redemption or sinking fund payments with respect to the 9 3/8% 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. If a subsidiary of the Company guarantees other subordinated indebtedness of the Company, the subsidiary must also guarantee the 9 3/8% Notes. Currently, none of the Company's subsidiaries guarantees subordinated indebtedness of the Company. The 9 3/8% Notes are unsecured general obligations of the Company, and are subordinated in right of payment to all existing and future senior indebtedness of the Company. In the event of a defined change in control, the Company will be required to make an offer to repurchase all outstanding 9 3/8% Notes at 101% of the principal amount thereof, plus accrued and unpaid interest to the date of redemption.

(b) In July 1999, the Company authorized a new issuance of $260.0 million of 9 1/2% Senior Subordinated Notes due June 1, 2008 ("9 1/2% Notes"). The Company offered to exchange the new notes for its outstanding $160.0 million of 9 1/2% Senior Subordinated Notes due 2006 ("Old 9 1/2% Notes") and $100.0 million of 8 7/8% Senior Subordinated Notes due 2008 ("8 7/8 % Notes"). In August 1999, the Company received tenders to exchange $157. 5 million of its Old 9 1/2% Notes and $99. 9 million of the 8 7/8% Notes. In connection with

the exchange offers, the Company solicited consents to proposed amendments to the indentures under which the old notes were issued. These amendments streamline the Company's covenant structure and provide the Company with additional flexibility to pursue its operating strategy. The exchange was accounted for as a debt modification. As such, the consideration that the Company paid to the holders of the Old 9 1/2% Notes who tendered in the exchange offer (equal to 3% of the outstanding principal amount of the Old 9 1/2% Notes exchanged, or $4.7 million) was accounted for as deferred financing costs. Also in connection with this exchange offer, the Company incurred a total of $3.1 million in third-party fees during the third and fourth quarters of 1999, which are included in other expense.

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

(c) In April 1996, the Company financed a portion of the purchase price of the Unocal Properties with proceeds from the sale to the public of a principal amount of $160.0 million, Old 9 1/2% Notes. In August 1999, most of the Old 9 1/2% Notes, except for $2,540,000, were exchanged for 9 1/2% Notes. In October 1999, the Company purchased $100,000 of the remaining Old 9 1/2% Notes. No significant costs were incurred in connection with the early retirement of the $100,000 notes. Interest on the Old 9 1/2% Notes accrues at the rate of 9 1/2% per annum and is payable semi-annually in arrears on April 15 and October 15. The Old 9 1/2% Notes are redeemable, in whole or in part, at the option of the Company, on or after April 15, 2001, under certain conditions. The Company is not required to make mandatory redemption or sinking fund payments with respect to the Old 9 1/2% Notes. The Old 9 1/2% Notes were guaranteed by certain of Nuevo's subsidiaries until February 1998, at which time such subsidiaries were released as guarantors. The Old 9 1/2% Notes are unsecured general obligations of the Company, and are subordinated in right of payment to all existing and future senior indebtedness of the Company.

(d) In February 1995, in connection with the purchase of the stock of Amoco Congo Production Company, the Company negotiated with the Overseas Private Investment Corporation ("OPIC") and an agent bank for a non-recourse credit facility in the amount of $25.0 million. The security for such facility is the assets and stock of the Nuevo Congo Company ("NCC"). The credit facility expired in June 1999. The initial drawdown on the facility was $8.8 million to finance a portion of the purchase price. A portion of the remaining outstanding commitment, $6.0 million, was drawn down in January 1996 to fund the first phase of the development drilling program in the Congo. The loan agreement required a sixteen-quarter repayment period and was fully paid in April 2000.

(e) Nuevo's Third Amended and Restated Credit Agreement, (the "Credit Agreement"), dated June 7, 2000, provides for secured revolving credit availability of up to $410.0 million (subject to a semi-annual borrowing base determination) 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.

The borrowing base is subject to a semi-annual borrowing base determination within 60 days following March 1 and August 15 of each year. The borrowing base determination establishes the maximum borrowings that may be outstanding under the credit facility, and is determined by a 60% vote of the 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 the

Company's oil and gas reserves based on its own assumptions regarding future prices, production, costs, risk factors and discount rates, and (ii) on 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, the Company would be required to repay such excess over a defined period of time. As of December 31, 2000, the Company's borrowing base was $225.0 million. There were no outstanding borrowings under this facility at December 31, 2000.

Amounts outstanding under the credit facility bear interest at a rate equal to the London Interbank Offered Rate ("LIBOR") plus an amount which increases as borrowing base utilization increases.

The Credit Agreement has customary covenants including, but not limited to, covenants with respect to the following matters: (i) limitations on certain restricted payments and investments; (ii) limitations on guarantees and indebtedness; (iii) limitations on prepayments of subordinated and certain other indebtedness; (iv) limitations on mergers and consolidations, on certain types of acquisitions and on the issuance of certain securities by subsidiaries; (v) limitations on liens; (vi) limitations on sales of properties; (vii) limitations on transactions with affiliates; (viii) limitations on derivative contracts; and (ix) limitations on debt in subsidiaries. The Company is 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. The Company was in compliance with all covenants of the Credit Agreement at December 31, 2000, and does not anticipate any issues of non-compliance arising in the foreseeable future.

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

2001	$ --
2002	--
2003	--
2004	--
2005	--
Thereafter	409,727
Total debt	$ 409,727

Based upon the quoted market price, the fair value of the 9 3/8% Notes was estimated to be $150.0 million at December 31, 2000; the fair value of the 9 1/2% Notes was estimated to be $260.4 million and $254.6 million at December 31, 2000 and 1999, respectively; and the fair value of the Old 9 1/2% Notes was estimated to be $2.5 million and $2.4 million at December 31, 2000 and 1999, respectively. For the OPIC credit facility and other debt, for which no quoted prices are available, management believes the carrying value of the debt materially represents the fair value of the debt at December 31, 1999.

9. Income Taxes

Income tax expense (benefit) is summarized as follows (amounts in thousands):

	Year Ended De	
	2000	1999
Current		
Federal	$ (371)	$ 1,0
State	--	1
	(371)	1,2
Deferred		
Federal	7,102	(8,4
State	1,661	1,8
	8,763	(6,5
Total income tax expense (benefit)	$8,392	$(5,3

NUEVO ENERGY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS--(Continued)

Also for the year ended December 31, 2000, the Company recorded a tax benefit of $537,000 related to a cumulative effect of a change in accounting principle (see Note 2).

A deferred tax benefit related to the exercise of employee stock options of approximately $0.5 million and $0.2 million was allocated directly to additional paid-in capital in 2000 and 1999, respectively.

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
	2000
Statutory federal income tax rate	35.0 %
(Decrease) increase in tax rate resulting from:	
State income taxes, net of federal benefit	5.2
(Decrease) increase in valuation allowance	--
Nondeductible travel and entertainment and other	0.1
	40.3 %

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 (amounts in thousands):

	As of December 31,	
	2000	
Net operating loss carryforwards	$ 51,033	$ 4
Alternative minimum tax credit carryforwards	1,704	
Capital loss carryforwards	--	
Total deferred income tax assets	52,737	4
Less: valuation allowance	(1,777)	(
Net deferred income tax assets	50,960	4
Property and equipment	(31,338)	(1
Equity in foreign subsidiaries	(1,684)	
State income taxes	(1,656)	

Total deferred income tax liabilities...............	(34,678)	(2
Net deferred income tax asset.........................	$ 16,282	$ 2

At December 31, 2000, the Company had a net operating loss carryforward for regular tax of approximately $146.0 million, which will begin expiring in 2018. The alternative minimum tax credit carryforward of $1.7 million does 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. At December 31, 1998, the Company determined that it was more likely than not that a portion of the deferred tax assets would not be realized and the valuation allowance was increased by $16.9 million to a total valuation allowance of $17.6 million. At December 31, 1999, however, the Company determined that it was more likely than not that most of the deferred tax assets would be realized, based on current projections of taxable income due to higher commodity prices at year-end 1999, and the valuation allowance was decreased by $15.9 million to a total valuation allowance of $1.8 million. The decrease in the valuation allowance was accounted for as a reduction in 1999 deferred income tax expense.

10. INDUSTRY SEGMENT INFORMATION

The Company's operations are concentrated primarily in two segments: exploration and production of oil and natural gas, and gas plant and other facilities.

	As of a
	2000
	(Amo
Sales to unaffiliated customers:	
Oil and gas -- Domestic..	$290,774
Oil and gas -- Foreign...	40,881
Total sales..	331,655
Gain on sale of assets, net......................................	657
Interest and other income..	4,293
Total revenues...	$336,605
Operating profit (loss) before income taxes:	
Oil and gas -- Domestic (1)......................................	$ 84,747
Oil and gas -- Foreign...	14,899
	99,646
Unallocated corporate expenses...................................	34,738
Interest expense...	37,472
Dividends on TECONS..	6,613

Operating profit (loss) before income taxes	$ 20,823
Identifiable assets:	
Oil and gas -- Domestic	$613,658
Oil and gas -- Foreign	103,204
Gas plant and other facilities	11,455
	728,317
Corporate assets, investments and other	119,707
Total	$848,024
Capital expenditures:	
Oil and gas -- Domestic	$101,773
Oil and gas -- Foreign	11,694
Oil and gas capital expenditures	113,467
Less: Geological & geophysical, delay rentals and other expenses	(9,047)
Additions to oil and gas properties per Statement of Cash Flows	$104,420
Gas plant and other facilities	$ 3,388
Depreciation, depletion and amortization:	
Oil and gas -- Domestic	$ 57,819
Oil and gas -- Foreign	8,085
Gas plant and other facilities	512
Corporate	954
	$ 67,370

(1) Includes gain on sale of the East Texas natural gas asset of $80.2 million for the year end

Credit Risks due to Certain Concentrations

In 2000, 1999 and 1998, the Company had one customer that accounted for 84%, 79%, and 60% of oil and gas revenues, respectively. In 2000, 1999 and 1998, the Company had another customer that accounted for 11%, 12% and 10% of oil and gas revenues, respectively.

In February 2000, the Company entered into a 15-year contract, effective January 1, 2000, to sell substantially all of its current and future California crude oil production to Tosco Corporation. The contract provides pricing based on a fixed percentage of the NYMEX crude oil price for each type of crude oil that Nuevo produces in California. Therefore, the actual price received as a percentage of NYMEX will vary with the Company's production mix. Based on the Company's current production mix, the price received by Nuevo for its California production is expected to average approximately 72% of WTI. While the contract does not reduce the Company's exposure to price volatility, it does effectively eliminate the basis differential risk between the NYMEX price and the field price of the Company's California oil production. The Tosco contract permits the Company under certain circumstances to separately market up to ten percent of its California crude production. The Company exercised this right and, effective January 1, 2001, began selling 5,000 BOPD of its San Joaquin Valley oil production to a third party under a one-year contract containing NYMEX pricing.

11. CONTINGENCIES AND OTHER MATTERS

In August 1996, the Company had been named as a defendant in Gloria Garcia Lopez and Husband, Hector S. Lopez, Individually, and as successors to Galo Land & Cattle Company v. Mobil Producing Texas & New Mexico, et al. in the 79th Judicial District Court of Brooks County, Texas. On June 9, 2000, the parties entered into a memorandum of settlement agreement, pursuant to which the lawsuit was dismissed, the defendants paid the plaintiffs $12.0 million and the lease agreement was amended. Nuevo's working interest in these properties is 20%, and its share of the settlement payment was approximately $2.4 million.

On September 22, 2000, the Company was named as a defendant in the lawsuit Thomas Wachtell et al. versus Nuevo Energy Company in the Superior Court of Los Angeles County, California. The plaintiffs, who own certain interests in the Point Pedernales properties, have asserted numerous causes of action including breach of contract, fraud and conspiracy in connection with the plaintiff's allegation that: (i) royalties have not been properly paid to them for production from the Point Pedernales field, (ii) payments have not been made to them related to production from the Sacate field, and, (iii) the Company has failed to recognize the plaintiff's interests in the Tranquillon Ridge project. The plaintiffs have not specified damages. The Company has not yet been required to file an answer, but believes the allegations are without merit and intends to vigorously contest these claims. Management does not believe that the outcome of this matter will have a material adverse impact on the Company's operating results, financial condition or liquidity.

The Company has been named as a defendant in certain other lawsuits incidental to its business. Management does not believe that the outcome of such litigation will have a material adverse impact on the Company's operating results or financial condition. However, these actions and claims in the aggregate seek substantial damages against the Company and are subject to the inherent uncertainties in any litigation. The Company is defending itself vigorously in all such matters.

In March 1999, the Company discovered that a non-officer employee had fraudulently authorized and diverted for personal use Company funds totaling $5.9 million, $1.6 million in 1999 and the remainder in 1998, that were intended for international exploration. The Board of Directors engaged a Certified Fraud Examiner to conduct an in-depth review of the fraudulent transactions. The investigation confirmed that only one employee was involved in the matter and that all misappropriated funds were identified. The Company has reviewed and, where appropriate, strengthened its internal control procedures. In August 2000, the Company recorded $1.5 million of other income for a partial reimbursement of these previously expensed funds, resulting from the negotiated settlement of a related legal claim.

In September 1997, there was a spill of crude oil into the Santa Barbara Channel from a pipeline that connects the Company's Point Pedernales field with shore-based processing facilities. The volume of the spill was estimated to be 163 barrels 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 insurance held by the Company, less the Company's deductibles of $120,000. The Company incurred clean-up and repair costs of $ 0.3 million, $0.5 million, and $2.4 million during 2000, 1999, and 1998, respectively. As of December 31, 2000, the Company had received insurance reimbursements of $4.1 million, with a remaining insurance receivable of $1.3 million. For amounts not covered by insurance, including the

$120,000 deductible, the Company recorded lease operating expenses of $0.4 million and $0.5 million during 1999 and 1998, respectively. No such expenses were recorded in 2000. Additionally, the Company has exposure to certain costs that are expected to be recoverable from insurance, including certain fines, penalties, and damages, for which the Company accrued $0.7 million as of December 31, 2000, as a receivable and payable. The Company also has exposure to costs that may not be recoverable from insurance, including certain fines, penalties, and damages. Such costs are not quantifiable at this time, but are not expected to be material to the Company's operating results, financial condition or liquidity.

The Company's 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 its foreign operations, the Company 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. The Company attempts to conduct its business and financial affairs so as to protect against political and economic risks applicable to operations in the various countries where it operates, but there can be no assurance that the Company will be successful in so protecting itself. A portion of the Company's investment in the Congo is insured through political risk insurance provided by 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. The Company has no deductible for this insurance.

In connection with their respective February 1995 acquisitions of two subsidiaries (each a "Congo subsidiary") owning interests in the Yombo field offshore Congo, the Company 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, the Company 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 the Company or CMS of its respective Congo subsidiary, (ii) either Congo subsidiary's sale of its interest in the Yombo field, (iii) the acquisition of the Company or CMS by another consolidated group or (iv) the failure of the Company or CMS's Congo subsidiary 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 US income tax purposes. The Company and CMS have agreed among themselves 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. The Company's potential direct liability could be as much as $42.5 million if a triggering event with respect to the Company occurs. Additionally, the Company believes that CMS's liability (for which the Company would be jointly liable with an indemnification right against CMS) could be as much as $61.0 million. The Company does not expect a triggering event to occur with respect to it or CMS and does not believe the agreement will have a material adverse effect upon the Company.

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 the Company's operations in the Congo, no assurances can be made that continued political unrest in West Africa will not have a material adverse effect on the Company and its operations in the Congo in the future.

12. FINANCIAL INSTRUMENTS

The Company follows formal policies regarding the management of oil price risk to ensure the Company's ability to optimally manage its portfolio of investment opportunities. To accomplish this, the policy requires that derivative financial instruments must be entered into at least 18 months in advance of the effective period. To the

extent that future markets over a forward 18 month period are significantly higher than long term norms, the Company will hedge as much of its production as is necessary to meet its policy goals for that period.

For 2001, the Company has entered into swap arrangements on 26,000 BOPD for the first quarter at an average WTI price of $19.52, for the second quarter on 25,000 BOPD at an average WTI price of $19.54, for the third quarter on 20,000 BOPD at an average WTI price of $21.22, and for the fourth quarter on 15,500 BOPD at an average WTI price of $22.95 per barrel. Subsequent to December 31, 2000, the Company entered into swaps on an additional 1,200 BOPD for the second quarter, bringing the total to 26,200 BOPD at an average price of $19.84 per barrel. On a physical volume basis, these hedges cover 47% of the Company's estimated 2001 oil production. At December 31, 2000, the market value of the swaps in place for 2001was a loss of $35.1 million.

For 2002, the Company has entered into swap arrangements on 12,500 BOPD for the first quarter at an average WTI price of $25.91 per barrel. For the remainder of 2002, the Company purchased put options with a strike price of $22.00 per barrel WTI, on 19,000 BOPD for the second quarter, and on 14,000 BOPD for both the third and fourth quarters. At December 31, 2000, the market value of these hedge positions is a gain of $8.3 million. All of these agreements expose the Company to counterparty credit risk to the extent that the counterparty is unable to meet its settlement commitments to the Company.

Determination of 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 the Company's other investments, derivative financial instruments and long-term debt at December 31, 2000 and 1999.

	December 31, 2000		
	Carrying Value	Approximate Fair Value	C
Other investments	$ 78	$ 78	
Derivative Instruments:			
Option premium	5,595	11,088	
Commodity price swaps	--	(32,253)	
Long-term debt (see Note 8)	409,727	412,823	
TECONS	115,000	60,950	

13. CONTINGENT PAYMENT AND PRICE SHARING AGREEMENTS

In connection with the acquisition from Unocal in 1996 of the properties located in California, the Company is obligated to make a contingent payment for the years 1998 through 2004 if oil prices exceed thresholds set forth in the agreement with Unocal. Any contingent payment will be 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, 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). The Company accumulates credits to offset the contingent payment when prices are $.50 per Bbl or more below the minimum price. The Company computes this calculation annually and had accumulated $8.5 million in price credits as of December 31, 2000, which will be used to reduce future amounts owed under the contingent payment. There is no value attributable to this credit other than to offset future payments. At the end of 2004, if the Company still maintains a credit position with respect to this agreement, the credit will expire worthless. As of December 31, 2000, the Company had never been obligated to make a payment to Unocal under the terms of the agreement.

However, a continuation of higher than normal oil price realizations is expected to trigger payments under this agreement beginning in March of 2002.

In connection with the acquisition of the Congo properties in 1995, the

Company entered into a price sharing agreement with the seller. There is no termination date associated with this agreement. 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, then the Company is obligated to pay the seller 50% of the difference between the benchmark price and the actual price received, for all the barrels associated with this acquisition. The benchmark price for 1999 was $14.79 per Bbl, and the benchmark price for 2000 was $15.19 per Bbl The benchmark price increases each year, based on the increase in the Consumer Price Index. For 2000, the effect of this agreement was that Nuevo only owned upside above $15.19 per Bbl on approximately 56% of its Congo production. In 2000, the Company was obligated to pay the seller $5.4 million pursuant to this price sharing agreement. This obligation was accounted for as a reduction in oil revenues. No such payments were due in 1998 or 1999.

The Company 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. The Company is entitled to all revenue proceeds up to $9.00 per Bbl, with the excess revenue over $9.00 per Bbl, if any, shared among the Company and the original owners from whom Torch acquired its interest. Amounts below $9.00 per Bbl are owned by the Company and the other working interest owners based on their respective ownership interests. For 2000, the effect of this agreement is that Nuevo was entitled to receive the pricing upside above $9.00 per Bbl on approximately 34% of the gross Point Pedernales production. As of December 31, 2000, the Company had $581,000 accrued as its obligation under this agreement. As of December 31, 1999, the Company had $5.1 million accrued as its obligation under this agreement, which was paid in the first quarter of 2000.

14. 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, 2000 are based primarily on reserve reports prepared by the independent petroleum engineering firm of Ryder Scott Company. Reserve quantities and future production for previous years are based primarily upon reserve reports prepared by 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 realized prices at year-end 2000, of $19.51 per Bbl and $13.94 per Mcf, and are adjusted for the effects of contractual agreements with Unocal and Amoco in connection with the California and Congo property acquisitions (see Note 13). Natural gas prices were unusually high at December 31, 2000. Natural gas costs are a significant component of the Company's thermal operating costs in California. As such, the unusually high prices at year-end 2000 had an unfavorable effect on the Company's reserves for its thermal oil producing properties.

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 the Company's 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.

NUEVO ENERGY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS--(Continued)

Costs incurred (amounts in thousands)-

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

	Year
	2000
Domestic	
Property acquisition:	
Proved properties	$ --
Unproved properties	4,892
Exploration	5,591
Development (1):	
Proved reserves	79,857
Unproved reserves	11,433
	$101,773
FOREIGN	
Property acquisition:	
Proved properties	$ --
Unproved properties	479
Exploration	6,467
Development:	
Proved reserves	4,406
Unproved reserves	342
	$ 11,694
Total	
Property acquisition:	
Proved properties	$ --
Unproved properties	5,371
Exploration	12,058
Development:	
Proved reserves	84,263
Unproved reserves	11,775
	$113,467

========

(1) Includes capitalized interest directly related to development activities of $0.3 million in

NUEVO ENERGY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS--(Continued)

Capitalized costs (amounts in thousands)-

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

	A
	2000
Domestic	
Proved properties	$ 986,889
Unproved properties	25,341
Total capitalized costs	1,012,230
Accumulated depreciation, depletion and amortization	(461,225)
Net capitalized costs	$ 551,005
FOREIGN	
Proved properties	$ 84,558
Unproved properties	5,445
Total capitalized costs	90,003
Accumulated depreciation, depletion and amortization	(29,008)
Net capitalized costs	$ 60,995
TOTAL	
Proved properties	$1,071,447
Unproved properties	30,786
Total capitalized costs	1,102,233
Accumulated depreciation, depletion and amortization	(490,233)
Net capitalized costs	$ 612,000

NUEVO ENERGY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS--(Continued)

Results of operations for producing activities (amounts in thousands) --

	Year
	2000
Domestic	
Revenues from oil and gas producing activities	$ 290,774
Production costs	(142,850)
Exploration costs	(5,503)
Depreciation, depletion and amortization	(57,819)
Provision for impairment of oil and gas properties	--
Income tax (provision) benefit	(34,096)
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 50,506
FOREIGN	
Revenues from oil and gas producing activities	$ 40,881
Production costs	(13,626)
Exploration costs	(4,271)
Depreciation, depletion and amortization	(8,085)
Provision for impairment of oil and gas properties	--
Income tax (provision) benefit	(6,005)
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 8,894
TOTAL	
Revenues from oil and gas producing activities	$ 331,655
Production costs	(156,476)
Exploration costs	(9,774)
Depreciation, depletion and amortization	(65,904)
Provision for impairment of oil and gas properties	--
Income tax (provision) benefit	(40,101)
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 59,400

The Company's estimated total proved and proved developed reserves of oil and gas are as follows:

	Year Ended December 31,	
	2000	1999

	Oil* (Mbbl)	Gas (Mmcf)	Oil* (Mbbl)	Gas (Mmcf)	Oil* (Mbbl)
DOMESTIC					
Proved reserves at beginning of year.......	239,190	145,125	164,300	403,256	202,77
Revisions of previous estimates............	(40,340)	20,740	61,168	56,097	(41,39
Extensions and discoveries.................	15,945	17,678	10,795	11,800	17,69
Production.................................	(15,591)	(15,215)	(15,892)	(17,620)	(17,34
Sales of reserves in-place.................	(2,512)	(2,351)	(10,270)	(335,927)	(1,59
Purchase of reserves in-place..............	--	--	29,089	27,519	4,17
Proved reserves at end of year.............	196,692	165,977	239,190	145,125	164,30
Proved developed reserves--					
Beginning of year........................	174,846	112,204	123,077	308,667	143,48
End of year..............................	160,039	122,500	174,846	112,204	123,07
Foreign					
Proved reserves at beginning of year.......	26,048	--	25,841	--	24,49
Revisions of previous estimates............	(1,003)	--	2,042	--	(42
Extensions and discoveries.................	--	--	--	--	-
Production.................................	(1,843)	--	(1,835)	--	(1,46
Sales of reserves in-place.................	--	--	--	--	-
Purchase of reserves in-place..............	--	--	--	--	3,22
Proved reserves at end of year.............	23,202	--	26,048	--	25,84
Proved developed reserves--					
Beginning of year........................	13,749	--	10,242	--	9,52
End of year..............................	11,013	--	13,749	--	10,24
Total					
Proved reserves at beginning of year.......	265,238	145,125	190,141	403,256	227,26
Revisions of previous estimates............	(41,343)	20,740	63,210	56,097	(41,81
Extensions and discoveries.................	15,945	17,678	10,795	11,800	17,69
Production.................................	(17,434)	(15,215)	(17,727)	(17,620)	(18,80
Sales of reserves in-place.................	(2,512)	(2,351)	(10,270)	(335,927)	(1,59
Purchase of reserves in-place..............	--	--	29,089	27,519	7,40
Proved reserves at end of year.............	219,894	165,977	265,238	145,125	190,14
Proved developed reserves--					
Beginning of year........................	188,595	112,204	133,319	308,667	153,01
End of year..............................	171,052	122,500	188,595	112,204	133,31

* Includes estimated NGL reserves.

NUEVO ENERGY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS--(Continued)

Discounted future net cash flows (amounts in thousands) --

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

	Year
	2000
Domestic	
Future cash inflows	$ 6,168,033
Future production costs	(2,968,448)
Future development costs	(349,150)
Future net inflows before income tax	2,850,435
Future income taxes	(896,974)
Future net cash flows	1,953,461
10% discount factor	(803,899)
Standardized measure of discounted future net cash flows	$ 1,149,562
FOREIGN	
Future cash inflows	$ 521,831
Future production costs	(235,825)
Future development costs	(54,475)
Future net inflows before income tax	231,531
Future income taxes	(70,452)
Future net cash flows	161,079
10% discount factor	(55,752)
Standardized measure of discounted future net cash flows	$ 105,327
Total	
Future cash inflows	$ 6,689,864
Future production costs	(3,204,273)
Future development costs	(403,625)
Future net inflows before income tax	3,081,966
Future income taxes	(967,426)
Future net cash flows	2,114,540
10% discount factor	(859,651)
Standardized measure of discounted future net cash flows	$ 1,254,889

*In addition to the information presented in the above table, the Company had entered into swap arrangements on a portion of its future crude production as of December 31, 2000 (see Note 12). The effects of these hedges would decrease the PV-10 by approximately $39.3 million as of December 31, 2000.

[THIS PAGE NEEDS TO BE REWORKED]

NUEVO ENERGY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS--(Continued)

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

	Year
	2000
Domestic	
Standardized measure -- beginning of year	$ 890,172
Sales, net of production costs	(147,924)
Purchases of reserves in-place	--
Net change in prices and production costs	387,009
Extensions, discoveries and improved recovery, net of future production and development costs	181,885
Changes in estimated future development costs	(8,806)
Development costs incurred	79,857
Revisions of quantity estimates	(233,132)
Accretion of discount	110,162
Net change in income taxes	(149,592)
Sales of reserves in-place	(9,242)
Changes in production rates and other	49,173
Standardized measure -- end of year	$1,149,562
FOREIGN	
Standardized measure -- beginning of year	$ 117,001
Sales, net of production costs	(27,255)
Purchases of reserves in-place	--
Net change in prices and production costs	19,595
Extensions, discoveries and improved recovery, net of future production and development costs	--
Changes in estimated future development costs	(7,167)
Development costs incurred	4,406
Revisions of quantity estimates	(7,204)
Accretion of discount	14,300
Net change in income taxes	(7,284)
Changes in production rates and other	(1,065)
Standardized measure -- end of year	$ 105,327
Total	
Standardized measure -- beginning of year	$1,007,173
Sales, net of production costs	(175,179)
Purchases of reserves in-place	--
Net change in prices and production costs	406,604
Extensions, discoveries and improved recovery, net of future production and development costs	181,885
Changes in estimated future development costs	(15,973)
Development costs incurred	84,263
Revisions of quantity estimates	(240,336)
Accretion of discount	124,462

Net change in income taxes..................................	(156,876)
Sales of reserves in-place..................................	(9,242)
Changes in production rates and other.......................	48,108
Standardized measure -- end of year.........................	$1,254,889

*In addition to the information presented in the above table, the Company had entered into swap arrangements on a portion of its future crude production as of December 31, 2000 (see Note 12). The effects of these hedges would decrease the PV-10 by approximately $39.3 million as of December 31, 2000.

NUEVO ENERGY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS--(Continued)

SELECTED QUARTERLY FINANCIAL DATA (AMOUNTS IN THOUSANDS, EXCEPT PER SHARE DATA) (UNAUDITED):

	Quarter Ended (1)(2)			
	March 31, 2000	June 30, 2000	September 30, 2000	D
Revenues......................................	$ 71,505	$ 72,171	$91,274	
Operating earnings............................	$ 20,372	$ 20,505	$32,689	
Net income....................................	$ 651	$ 263	$ 8,850	
Earnings per Common share -- Basic............	$ 0.04	$ 0.02	$ 0.51	
Earnings per Common share -- Diluted..........	$ 0.04	$ 0.00	$ 0.49	

	Quarter Ended (1)(2)			
	March 31, 1999	June 30, 1999	September 30, 1999	D
Revenues......................................	$126,643	$ 52,860	$70,248	
Operating (loss) earnings.....................	$(11,803)	$ (8,125)	$15,554	
Net income (loss) (3).........................	$ 31,342	$(15,558)	$(2,756)	
Earnings (loss) per Common share -- Basic......	$ 1.58	$ (0.78)	$ (0.14)	
Earnings (loss) per Common share -- Diluted....	$ 1.58	$ (0.78)	$ (0.14)	

(1) Certain reclassifications of prior period amounts have been made to conform with the current presentation.
(2) Results for the 2000 quarters have been revised due to a change in accounting for processed fuel oil and natural gas liquids inventories (see Note 2).
(3) Includes a fourth quarter decrease in the deferred tax asset valuation allowance of $15.9 million.

NUEVO ENERGY COMPANY

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

On March 9, 2001, Nuevo Energy Company ("Nuevo") notified KPMG LLP ("KPMG") that their engagement as Nuevo's independent accountants will be terminated following the issuance of their report on Nuevo's consolidated financial statements for the fiscal year ended December 31, 2000. On March 9, 2001, the Board of Directors of Nuevo, on the recommendation of the Audit Committee, appointed Arthur Andersen LLP as Nuevo's independent accountants to audit its consolidated financial statements for the year ending December 31, 2001.

Nuevo and KPMG have not, in connection with the audit of Nuevo's consolidated financial statements for each of the prior two years ended December 31, 2000 and December 31, 1999 or for any subsequent or interim period prior to and including March 9, 2001, had any disagreement on any matter of accounting principles or practice, financial statement disclosure, or auditing scope or procedure, which disagreement, if not resolved to KPMG's satisfaction, would have caused KPMG to make reference to the subject matter of the disagreement in connection with its reports.

The reports of KPMG on the Nuevo financial statements for the past two fiscal years did not contain an adverse opinion or a disclaimer of opinion and were not qualified or modified as to uncertainty or audit scope.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required by this item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after December 31, 2000. Such information is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after December 31, 2000. Such information is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by this item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after December 31, 2000. Such information is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by this item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after December 31, 2000. Such information is incorporated herein by reference.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) 1. and 2. Financial Statements:

See index to Consolidated Financial Statements and Supplemental Information in Item 8, which information is incorporated herein by reference.

3. Exhibits

(3) Articles of Incorporation and bylaws.

3.1 Certificate of Incorporation of Nuevo Energy Company (Incorporated by reference from Exhibit 3.1 to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 1999).

3.2 Certificate of Amendment to the Certificate of Incorporation of Nuevo Energy Company (Incorporated by reference from Exhibit 3.2 to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 1999).

3.3 Bylaws of Nuevo Energy Company (Incorporated by reference from Exhibit 3.3 to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 1999).

3.4 Amendment to section 3.1 of the Bylaws of Nuevo Energy Company (Incorporated by reference from Exhibit 3.4 to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 1999).

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

4.1 Specimen Stock Certificate (Incorporated by reference to Exhibit 4.1 to Registration Statement on 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. (Incorporated by reference from Exhibit 4.1 to 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. (Incorporated by reference from 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. (Incorporated by reference from 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. (Incorporated by reference from Exhibit 4.4 to Form 8-K filed on December 23, 1996).

4.7 Form of Certificate representing TECONS. (Incorporated by reference from 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 (incorporated by reference to Exhibit 1 to the Company's 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. (Incorporated by reference to Exhibit 4.11 of Form 10-K for the year ended December 31, 1997.)

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 (Incorporated by reference from Exhibit 4.10 to Registration Statement on 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 (Incorporated by reference from Exhibit 4.11 to Registration Statement on 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. (Incorporated by reference from Exhibit 4.12 to Registration Statement on 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 (Incorporated by reference from Exhibit 4.12 to Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2000).

4.14 Registration Agreement dated September 26, 2000, between Nuevo Energy Company and Banc of America Securities LLC, Banc One Capital Markets, Inc. and J.P. Morgan & Co. (Incorporated by reference from Exhibit 4.13 to Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2000).

(10) Material Contracts.

10.1 Third Restated Credit Agreement dated June 7, 2000, between Nuevo Energy Company (Borrower) and Bank of America N.A. (Administrative Agent), Bank One, NA (Syndication Agent), Bank of Montreal (Documentation Agent) and certain lenders (Incorporated by reference from Exhibit 10.1 to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2000).

10.2 1990 Stock Option Plan of the Company, as amended (Incorporated by reference from Exhibit 10.8 to Registration Statement on Form S-1 dated July 13, 1992).

10.3 1993 Stock Incentive Plan, as amended (Incorporated by reference from Exhibit 4.2 to Registration Statement on Form S-8 (No. 333-21063) filed on February 4, 1997.

10.4 1999 Stock Incentive Plan (Incorporated by reference from Exhibit 99.1) to Registration Statement on Form S-8 (No, 333-87899) filed on September 28, 1999).

10.5 Nuevo Energy Company Deferred Compensation Plan (Incorporated by reference from Exhibit 99 to Registration Statement on Form S-8 (No. 333-51217) filed on April 28, 1998).

10.6 Stock Purchase Agreement, dated as of June 30, 1994, among Amoco Production Company ("APC"), Walter International Inc. ("Walter"), Walter Congo Holdings, Inc. ("Walter Holdings"), Walter International Congo, Inc. (before the merger "Walter Congo" and after the merger "Old Walter Congo"), Nuevo, Nuevo Holding and The Nuevo Congo Company (before the merger, "Nuevo Congo" and after the merger, "Old Nuevo Congo"). (Incorporated by reference from Exhibit 2.1 to Form 8-K dated March 10, 1995).

10.7 Amendment to Stock Purchase Agreement dated as of September 19, 1994, among APC, Walter Congo, Nuevo Congo, Walter Holdings, Nuevo Holding, Walter and Nuevo. (Incorporated by reference from Exhibit 2.2 to Form 8-K dated March 10, 1995).

10.8 Second Amendment to Stock Purchase Agreement dated as of October 15, 1994, among APC, Walter Congo, Nuevo Congo, Walter Holdings, Nuevo Holding, Walter and Nuevo. (Incorporated by reference from Exhibit 2.3 to Form 8-K dated March 10, 1995).

10.9 Third Amendment to Stock Purchase Agreement dated as of December 2, 1994, among APC, Walter Congo, Nuevo Congo, Walter Holdings, Nuevo Holding, Walter and Nuevo. (Incorporated by reference from Exhibit 2.4 to Form 8-K dated March 10, 1995.

10.10 Fourth Amendment to Stock Purchase Agreement dated as of February 23, 1995, among APC, Walter Congo, Nuevo Congo, Walter Holdings, Nuevo Holding, Walter and Nuevo. (Incorporated by reference from Exhibit 2.5 to Form 8-K dated March 10, 1995).

10.11 Tax Agreement dated as of February 23, 1995, executed by APC, Amoco Congo Exploration Company ("ACEC"), Amoco Congo Production Company ("ACPC"), Walter, Walter Holdings, Walter Congo, Nuevo, Nuevo Holding and Nuevo Congo. (Incorporated by reference from Exhibit 2.6 to Form 8-K dated March 10, 1995).

10.12 Agreement and Plan of Merger executed by Nuevo Congo, Nuevo Holding and APC dated February 24, 1995. (Incorporated by reference from Exhibit 2.7 to Form 8-K dated March 10, 1995).

10.13 Finance Agreement dated as of December 28, 1994, among Nuevo Holding, Nuevo Congo and The Overseas Private Investment Corporation ("OPIC"). (Incorporated by reference from Exhibit 2.8 to Form 8-K dated March 10, 1995).

10.14 Subordination Agreement dated December 28, 1994, among Nuevo Congo, Nuevo Holding, Walter Congo, Walter Holdings and APC. (Incorporated by reference from Exhibit 2.9 to Form 8-K dated March 10, 1995).

10.15 Guaranty covering the obligations of Nuevo Congo and Walter Congo under the Stock Purchase Agreement dated February 24, 1995, executed by Walter and Nuevo. (Incorporated by reference from

Exhibit 2.10 to Form 8-K dated March 10, 1995).

10.16 Inter-Purchaser Agreement dated as of December 28, 1994, among Walter, Old Walter Congo, Walter Holdings, Nuevo, Old Nuevo Congo and Nuevo Holding. (Incorporated by reference from Exhibit 2.11 to Form 8-K dated March 10, 1995).

10.17 Latent ORRI Contract dated February 25, 1995, among Walter, Walter Holdings, Walter Congo, Nuevo, Nuevo Holding and Nuevo Congo. (Incorporated by reference from Exhibit 2.12 to Form 8-K dated March 10, 1995).

10.18 Latent Working Interest Contract dated February 25, 1995, among Walter, Walter Holdings, Walter Congo, Nuevo, Nuevo Holding and Nuevo Congo. (Incorporated by reference form Exhibit 2.13 to Form 8-K dated March 10, 1995).

10.19 Asset Purchase Agreement dated as of February 16, 1996 between Nuevo Energy Company, the Purchaser, and Union Oil Company of California as Seller. (Incorporated by reference from Exhibit 2.1 to Form S-3 (No. 333-1504).

10.20 Asset Purchase Agreement dated as of April 4, 1997, by and among Torch California Company and Express Acquisition Company, as Sellers, and Nuevo Energy Company, as Purchaser. (Incorporated by reference from Exhibit 2.2 to Form S-3 (No. 333-1504)).

10.21 Employment Agreement with Douglas L. Foshee. (Incorporated by reference to Exhibit 10.23 to Form 10-K for the year ended December 31, 1997.)

10.22 Employment Agreement with Robert M. King. (Incorporated by Reference from Exhibit 10.24 to Form 10-K for the year ended December 31, 1998).

10.23 Employment Agreement with Dennis Hammond. (Incorporated by reference to Exhibit 10.26 to Form 10-K for the year ended December 31, 1997.)

10.24 Employment Agreement with Michael P. Darden. (Incorporated by reference from Exhibit 10.1 to Form 10-Q filed November 13, 1998).

10.25 Purchase and sale agreement dated October 16, 1998 between Nuevo Energy Company (Seller) and Samson Lone Star Limited Partnership (Buyer). (Incorporated by reference from Exhibit 10.28 to Form 10-K for the year ended December 31, 1998).

10.26 Master Services Agreement among the Company and Torch Energy Advisors Incorporated, Torch Operating Company, Torch Energy Marketing, Inc., and Novistar, Inc. dated January 1, 1999. (Incorporated by reference from Exhibit 10.29 to Form 10-K for the year ended December 31, 1998).

10.27 Employment Agreement with Bruce Murchison dated June 1, 1999. (Incorporated by reference from Exhibit 10.27 to Form 10-Q for the quarter ended September 30, 1999).

10.28 Employment Agreement with John P. McGinnis dated July 15, 1999. (Incorporated by reference from Exhibit 10.28 to Form 10-Q for the quarter ended September 30, 1999).

10.29 Crude Oil Purchase Agreement dated February 4, 2000 between Nuevo Energy Company and Tosco Corporation. (Incorporated by reference from Exhibit 10.1 to Form 8-K dated March 23, 2000).

10.30 Employment Agreement with Phillip Gobe dated February 26, 2001.

10.31 Severance Protection Agreement dated March 25, 2001.

(21) Subsidiaries of the Registrant

(23) Consents of experts and counsel:

23.1 Consent of KPMG LLP

(b) Reports on Form 8-K:

1. A Current Report on Form 8-K, dated November 13, 2000, reporting Item 9. Regulation FD Disclosure was filed on November 13, 2000.

2. A Current Report on Form 8-K, dated December 15, 2000, reporting Item 9. Regulation FD Disclosure was filed on December 15, 2000.

(99) Additional Exhibits

None.

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 14.

- 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, 2000, 1999 or 1998 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 28, 2001

By: /s/Douglas L. Foshee

Douglas L. Foshee
Chairman of the Board of Directors,
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/ Douglas L. Foshee — Date: March 28, 2001

Douglas L. Foshee
Chairman of the Board of Directors,
President and Chief Executive Officer
(Principal Executive Officer)

By: /s/ Robert M. King — Date: March 28, 2001

Robert M. King
Senior Vice President and
Chief Financial Officer (Principal Financial Officer)

By: /s/ Sandra D. Kraemer — Date: March 28, 2001

Sandra D. Kraemer
Controller (Principal Accounting Officer)

By: /s/ Robert L. Gerry III — Date: March 28, 2001

Robert L. Gerry III

Director

By:	/s/ Gary R. Petersen Gary R. Petersen Director	Date:	March 28, 2001
By:	/s/ Thomas D. Barrow Thomas D. Barrow Director	Date:	March 28, 2001
By:	/s/ Isaac Arnold, Jr. Director	Date:	March 28, 2001
By:	/s/ David Ross David Ross Director	Date:	March 28, 2001
By:	/s/ Robert W. Shower Robert W. Shower Director	Date:	March 28, 2001
By:	/s/ Charles M. Elson Charles M. Elson Director	Date:	March 28, 2001
By:	/s/ David H. Batchelder David H. Batchelder Director	Date:	March 28, 2001