MARINER ENERGY INC
Form 10-K
April 16, 2003

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

FORM 10-K

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2002

COMMISSION FILE NUMBER 333-12707

MARINER ENERGY, INC.
(Exact name of registrant as specified in its charter)

DELAWARE	86-0460233
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

2101 CITYWEST BLVD., SUITE 1900
HOUSTON, TEXAS 77042
(Address of principal executive offices including Zip Code)

(713) 954-5500
(Registrant's telephone number)

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

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[ ] No[X]

Note: The Company is not subject to the filing requirements of the Securities Exchange Act of 1934. This annual report is filed pursuant to contractual obligations imposed on the Company by an Indenture, dated as of August 1, 1996, under which the Company is the issuer of certain debt.

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]

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

The aggregate market value of the 1380 shares of voting stock held by affiliates of registrant as of June 28, 2002 (the last business day of the most recently completed second quarter) is indeterminable, as there is no established public trading market for the registrant's common stock.

As of March 4, 2003, there were 1,380 shares of the registrant's common stock outstanding. See Part III, Item 13. "Certain Relationships and Related

Party Transactions" related to common stock ownership and other entities related to registrant.

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Item

PART I

Mariner Energy, Inc. ("Mariner" or the "Company") has provided definitions for some of the natural gas and oil industry terms used in this report in the "Glossary" on page 82.

Cautionary Statement About Forward-Looking Statements

Some of the information in this Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. The forward-looking statements speak only as of the date made, and we undertake no obligation to update such forward-looking statements. These forward-looking statements may be identified by the use of the words "believe," "expect," "anticipate," "will," "contemplate," "would" and similar expressions that contemplate future events and subject to uncertainties. Actual results and trends in the future may differ materially depending on a variety of factors including, but not limited to the following matters:

- Impact of bankruptcy proceedings related to our ultimate parent, Enron Corp. and affiliates;

- cash flow and liquidity;

- financial position;

- business strategy;

- budgets;

- amount, nature and timing of capital expenditures, including future development costs;

- drilling of wells;

- natural gas and oil reserves;

- timing and amount of future production of natural gas and oil;

- operating costs and other expenses;

- prospect development and property acquisitions; and

- marketing of natural gas and oil.

Numerous important factors, risks and uncertainties may affect our operating results, including:

- The risks associated with exploration;

- the ability to find, acquire, market, develop and produce new properties;

- natural gas and oil price volatility;

- uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;

- operating hazards attendant to the natural gas and oil business;

- downhole drilling and completion risks that are generally not recoverable from third parties or insurance;

- potential mechanical failure or under-performance of significant wells;
- climatic conditions;
- availability and cost of material and equipment;
- delays in anticipated start-up dates;
- Loss of Royalty Relief on certain blocks

- actions or inactions of third-party operators of our properties;
- the ability to find and retain skilled personnel;
- availability of capital;
- the strength and financial resources of competitors;
- regulatory developments;
- environmental risks; and
- general economic conditions.

Any of the factors listed above and other factors contained in this annual report could cause our actual results to differ materially from the results implied by these or any other forward-looking statements made by us or on our behalf. We cannot provide assurance that future results will meet our expectations. You should pay particular attention to the risk factors and cautionary statements described under "Risk Factors" in "Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

(a) OVERVIEW

Mariner Energy, Inc. ("Mariner" or "Company") is an independent oil and natural gas exploration, development and production company with principal operations in the Gulf of Mexico and along the U.S. Gulf Coast. We have been an active explorer in the Gulf Coast area since the mid-1980s, when we operated as Hardy Oil & Gas USA Inc., and have increased our production and reserve base through the exploitation and development of internally generated prospects, which we refer to as growth "through the drillbit." In 1996, Joint Energy Development Investments Limited Partnership ("JEDI"), an affiliate of Enron Corp. ("Enron") and Enron North America Corp. ("ENA") (also see further description under "Enron" in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations"), along with management led a buyout from Hardy Oil & Gas, Plc. JEDI currently owns approximately 96%, while employees and former employees own the remaining 4% of Mariner Energy LLC, which owns 100% of Mariner Holdings, Inc. Mariner Holdings, Inc. owns all of the common stock of Mariner.

Since 1996, we significantly increased our focus in the Gulf of Mexico. Currently our strategy is to primarily focus our exploration efforts on Gulf of Mexico shelf (less than 1000 feet water depth) prospects with a secondary focus on Gulf of Mexico deepwater (greater than 1000 feet) opportunities leveraging our expertise in deepwater subsea field development technology that were tiebacks to near existing infrastructures (offshore platforms). Management believes that no other U.S. independent oil and gas exploration company has more experience then Mariner utilizing this technology in deepwater. In addition we operate the onshore Aldwell field located West Texas comprised of 80 producing wells and over 100 undeveloped locations

During 2002, we drilled 6 exploratory wells with 2 successes. We also commenced a 42 well drilling program in the Aldwell unit and as of December 31, 2002, 8 wells were completed and on production. Ryder Scott Company estimated that we had proved reserves of 202 Bcfe before the sale of our remaining interest in the Falcon Corridor (see Recent Events) as of December 31, 2002, of which 67% were natural gas and 33% were oil and condensate. Proved reserves included net reserve additions of 39 Bcfe, representing 100% of 2002's Company's production.

We expect our production for 2003 to be slightly lower than 2002's average rate of 100 MMcfe per day, after the sale of our remaining interest in the Falcon Corridor (see Recent Events). Our 2003 production rate is expected to average 93 Mcfe per day. As of March 4, 2003, our daily production was 98 Mcfe.

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In 2003, we expect to drill 8 to 12 exploratory wells. As of March 20, 2003 we have drilled three exploratory wells of which two have been successful (see Recent Events). Development activities in 2003 include the completion of our Roaring Fork and Vermillion 144 projects and development of the Swordfish discovery and several development wells in currently producing fields.

We anticipate capital expenditures for 2003, before capitalized indirect costs and proceeds from property conveyances of $103 million, to be approximately $41 million for leasehold acquisition, exploration drilling and $62 million for development projects, compared to our 2002 capital expenditures of approximately $96.4 million, before capitalized indirect costs and proceeds from property conveyances of $52.3 million. We expect to fund our capital expenditures by a combination of internally generated cash flow and proceeds from property conveyances, including the recently-announced sale of our remaining interest in the Falcon development project.

The following table sets forth certain summary information with respect to our oil and gas activities and results during the five years ended December 31, 2002. Reserve volumes and values were determined under the method prescribed by the Securities and Exchange Commission, which requires the application of year-end oil and natural gas prices, held constant throughout the projected reserve life. The year-end oil and gas prices utilized do not include any impact relating to hedging activities. See "Reserves" later in this item and Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations".

	YEAR ENDING DECEMBER 31, (dollars in millions unless otherwis		
	2002	2001	2000
PROVED RESERVES:			
Oil (MMbbls)	11.0	10.1	12.4
Natural gas (Bcf)	136.1	176.5	129.3

Natural gas equivalent (Bcfe)	202.2	237.1	203.6	
PRESENT VALUE OF ESTIMATED FUTURE NET REVENUES (1)	$515.0	$232.0	$1,043.2	$
ANNUAL RESERVE REPLACEMENT RATIO (2)	1.0	3.2	1.7	
CAPITAL EXPENDITURES AND DISPOSAL DATA:				
Capital costs incurred	$106.1	$164.5	$ 108.1	$
Proceeds from property conveyances	(52.3)	(90.5)	(29.0)	
Capital costs net of proceeds from property conveyances	53.8	74.0	79.1	
PERCENTAGE OF NET CAPITAL COSTS ATTRIBUTABLE TO:				
Lease acquisition	14.0%	5.4%	10.5%	
Exploratory drilling, geological and geophysical	24.3%	35.0%	19.6%	
Development and other	61.7%	59.6%	69.9%	
PRODUCTION:				
Oil (MMbls)	1.7	3.0	1.8	
Natural gas (Bcf)	29.6	18.8	25.7	
Natural gas equivalent (Bcfe)	39.8	36.7	36.3	
AVERAGE REALIZED SALES PRICE PER UNIT (excluding the effects of hedging):				
Oil ($/Bbl)	$21.60	$22.41	$ 29.53	$
Natural gas ($/Mcf)	3.35	4.86	4.07	
Gas equivalent ($/Mcfe)	3.41	4.31	4.32	
AVERAGE REALIZED SALES PRICE PER UNIT (including the effects of hedging):				
Oil ($/Bbl)	$22.85	$23.22	$ 21.54	$
Natural gas ($/Mcf)	4.03	4.57	3.24	

Gas equivalent ($/Mcfe)	3.97	4.22	3.24	
EXPENSES ($/MCFE):				
Lease operating	$ 0.65	$ 0.55	$ 0.47	$
Transportation	0.26	0.33	0.22	
General and administrative, net	0.19	0.25	0.18	

(1) Discounted at an annual rate of 10%. See "Glossary" included elsewhere in this annual report for the definition of "present value of estimated future net revenues".

(2) The annual reserve replacement ratio for a year is calculated by dividing aggregate reserve additions, including revisions, on a Mcfe basis for the year by actual production on a Mcfe basis for such year.

(b) RECENT EVENTS

On March 20, 2003, with bids totaling $3.9 million net to us, we were the apparent high bidder solely or with industry partners, on 11 out of 11 blocks on which we and our partners submitted bids in the Central Gulf of Mexico

Oil and Gas Lease Sale 185 held on that date. The blocks are in water depths ranging from approximately 20 feet to 1,500 feet. Mariner has a 100% working interest in five of the block and a 50% working interest in six blocks.

In January 2003 we made a deepwater Gulf of Mexico Discovery at "Harrier", East Breaks 759, and a shelf Gulf of Mexico discovery at Vermillion 144. Harrier was drilled in 4,100 feet of water to a total measured depth of 9,510 feet and encountered 315 net feet of gas pay. Mariner Energy holds a 25% working interest. Vermilion 144 was drilled in 87 feet of water to a total measured depth of 16,522 feet and encountered 90 net feet of pay. Mariner Energy is operator with a 42% working interest. First production is expected in June 2003.

In March 2003, we sold our remaining 25% working interest in our Falcon and Harrier discoveries and surrounding blocks, located in East Breaks area in the western Gulf of Mexico, for $121.6 million. We retained a 4 1/4 percent overriding royalty interest on seven non-producing blocks. The proceeds from the sale are expected to be used for debt reduction, capital expenditures, and other corporate purposes. At December 31, 2002, the Falcon project had 33.3 Bcfe assigned as proven oil and gas reserves to our interest.

(c) BUSINESS STRATEGY

Our business strategy is to increase reserves, production and cash flow by emphasizing growth through the drillbit. Our strategy consists of the following elements:

- BULK SEISMIC PURCHASES. In 2001 and the first quarter of 2002, we acquired three bulk seismic databases covering blocks in both the shelf and deepwater Gulf of Mexico. We believe maintaining a large 3-D seismic database allows us to identify high quality exploratory prospects. This seismic data allows us to better understand the geology before selecting prospects and increases the probability of accurately identifying the hydrocarbon-bearing zones.

- DIVERSIFY OUR PORTFOLIO. Currently, we maintain a significant amount of both shelf and deepwater Gulf of Mexico lease positions. Our strategy is to allocate approximately 30% to 40% of our capital budget for moderate risk exploration opportunities on both the Shelf and Deepwater. Shelf wells are less expensive, lower risk, and can be connected to market relatively quickly compared to Deepwater wells; however, the reserve targets are typically smaller than in the Deepwater. To manage the typical higher cost of Deepwater projects we focus on projects that will most likely utilize subsea tie back technology. Management believes that no other U.S. independent oil and gas company has utilized this technology more than Mariner. We believe this gives us a competitive advantage. In addition, we plan allocate 60% to 70% of our capital budget to develop our existing asset base to realize full asset value. This includes development of our Swordfish and Roaring Fork projects as well as our onshore infill drilling program at our Aldwell field located in West Texas.

- REDUCE DEPENDENCE ON CAPITAL INFUSIONS AND BORROWINGS. Historically, we have been required to sell various properties in order to manage our cash flow. In 2002, we sold half of our 50% working interest in our Falcon project for $52.3 million. This sale allowed us to maintain a high level of exploratory activity in addition to repaying our Revolving Credit Facility. In March 2003, we sold our remaining 25% working interest in our Falcon and Harrier projects for $121.6 million. The proceeds of the sale are expected to be used to reduce our corporate debt, maintain an active exploration program and other corporate purposes. We will continue to consider monetizing assets to achieve high rates of returns for our shareholders and reduce our overall risk profile.

- INTERNALLY GENERATE MOST OF OUR PROSPECTS. By internally generating most of our prospects, we believe we have better control over the quality of the prospects in which we participate, thereby increasing our chances for commercial success. Our geoscientists average more than 20 years of experience in the exploration and production business, including extensive experience in the Gulf and with major oil companies. Through our technical staff's understanding of the geology and geophysics of the Gulf, we intend to continue to generate the majority of our prospects internally.

- CONTROL ADMINISTRATIVE COSTS. In order for us to be competitive, we understand we must control administrative costs. In 2002, we continued to reduce our workforce and have caused an approximate 40% reduction since third quarter of 2001. We believe these reductions will allow us to control costs while maintaining necessary technical expertise. In addition, we expect to continue to generate reimbursements of costs through joint ventures with partners.

(d) RESERVES

The following table sets forth certain information with respect to our proved reserves by geographic area as of December 31, 2002. Reserve volumes and values were determined under the method prescribed by the Securities and Exchange Commission which requires the application of year-end prices held constant throughout the projected reserve life. The reserve information as of December 31, 2002 is based upon a reserve report prepared by the independent petroleum consulting firm of Ryder Scott Company, independent reserve engineers. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Therefore, without reserve additions in excess of production through successful exploration and development activities, the Company's reserves and production will decline. See Note 11 to the Financial Statements included elsewhere in this Annual Report for a discussion of the risks inherent in oil and natural gas estimates and for certain additional information concerning the proved reserves.

	AS OF DECEMBER 31, 2002				
	PROVED RESERVE QUANTITIES			PRESENT ESTIMATED FUTURE	
				DOLLARS IN	
GEOGRAPHIC AREA	OIL (MMBbls)	NATURAL GAS (Bcf)	TOTAL (Bcfe)	DEVELOPED	UNDEV
Deepwater Gulf............	3.2	92.0	111.2	175.6	$ 1
Gulf Shallow Water and Gulf Coast Onshore......	1.9	14.0	25.4	24.8	
Permian Basin.............	5.9	30.1	65.5	43.8	
Total...............	11.0	136.1	202.1	$ 244.2	$ 2

Proved Developed Reserves..	3.6	64.6	86.1	$ 240.0

(1) Discounted (at 10%) present value as of December 31, 2002 (year-end prices held constant).

Our estimates of proved reserves set forth in the foregoing table do not differ materially from those filed by us with other federal agencies.

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(e) OIL AND GAS PROPERTIES

(i) SIGNIFICANT PROPERTIES WITH PROVED RESERVES AS OF DECEMBER 31, 2002

We own oil and gas properties, both producing and non-producing, onshore in Texas and offshore in the Gulf, primarily in federal waters. Our 10 largest producing properties, as shown in the following table, accounted for approximately 93% of the Company's proved reserves as of December 31, 2002.

	OPERATOR	MARINER WORKING INTEREST	APPROXIMATE WATER DEPTH (FEET)	PRODUCING WELLS(3)
DEEPWATER GULF:				
East Breaks 579 (Falcon)(1)...........	Pioneer	25%	3,400	-
Green Canyon 472 (King Kong)..........	AGIP	50%	3,900	2
Mississippi Canyon 718 (Pluto)........	Mariner	51%	2,710	1
Ewing Bank 966 (Black Widow)..........	Mariner	69%	1,850	1
Green Canyon 516 (Yosemite)...........	AGIP	44%	3,850	1
Viosca Knoll 917 (Swordfish)..........	Mariner	15%	4,200	1
Mississippi Canyon 322 (Crater Lake)	Walter O&G	40%	700	-
GULF SHALLOW WATER AND GULF COAST ONSHORE:				
South Timbalier 316 (Roaring Fork)....	Westport	20%	450	-
Brazos A-105..........................	Unocal	12.5%	192	4
PERMIAN BASIN OF WEST TEXAS:				
Spraberry Aldwell Unit(2).............	Mariner	70.3%	Onshore	91
OTHER PROPERTIES:	--	--	--	36
TOTAL PROVED RESERVES:				137

(1) In March 2003 our remaining 25 working interest was sold for $121.6 million.

(2) We operate the unit and own working interests in individual wells ranging from approximately 33% to 84%.

(3) Producing wells or wells capable of producing.

Following is additional information regarding the properties in the table shown above.

GULF OF MEXICO

East Breaks 579 (Falcon) Mariner generated and acquired the Falcon prospect at a federal lease sale in August 1997. Currently Mariner has a 25% working interest in this Pioneer operated discovery located in the deepwater Gulf of Mexico 95 miles southeast of Corpus Christi, Texas in a water depth of 3,400 feet. In April 2001, the Mariner EB 579 #1 well was drilled and yielded a significant discovery that was sanctioned for development in October of the same year. Estimated net proved reserves from Falcon are 33.3 Bcfe. First production is anticipated to commence in March of 2003. (also see "Recent Events").

Green Canyon 472 / Green Canyon 516 (King Kong / Yosemite) In July 2000, we entered into an agreement to acquire Shell Exploration and Production Company's 50% working interest in the "King Kong" Gulf of Mexico development project. The project is located in approximately 3,900 feet of water in Green Canyon Blocks 472 and 473, approximately 150 miles southeast of New Orleans. We purchased Shell's interest for an undisclosed amount of cash and overriding royalty interest in the field, and have been named operator for development of the project. Agip Petroleum Co. Inc., as a successor to British Borneo, owns the remaining 50% working interest. This project began production in February 2002 and it ties back 16 miles to the Allegheny mini-TLP operated by Agip. In 2001 we drilled our "Yosemite" exploration prospect located adjacent to King Kong in Green Canyon Block 516. Yosemite is jointly developed with King Kong. As of December 31, 2002 the fields have produced 18.7 Bcfe net to us with the combined projects having an estimated net remaining proved reserves of 36.2 Bcfe.

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Mississippi Canyon 718 (Pluto) We acquired a 30% interest in this project in 1997, two years after British Petroleum discovered gas on the project. We later increased our ownership to 97%, acquiring operatorship and gaining overall control of project planning and implementation. In 1998, we increased our working interest to 100% and submitted a deepwater royalty relief application that was granted in July 1999. Due to high natural gas commodity prices, however, royalty relief did not apply to natural gas production in 2000 or 2001. In June 1999, we sold a 63% working interest in the project to Burlington Resources, Inc., reducing our working interest to 37%. After project payout, which occurred in the third quarter of 2000, our working interest increased to 51% and Burlington's working interest decreased to 49%. We developed the field with a single subsea well which is located in the Gulf approximately 150 miles southeast of New Orleans, Louisiana at a water depth of 2,710 feet and a flow line tied back approximately 29 miles to a production platform on the shelf. Production began on December 29, 1999 and through December 31, 2002 the field produced net 30.8 Bcfe and has an estimated remaining net proved reserves of 8.2 Bcfe, 60% of which was natural gas.

Ewing Bank 966 (Black Widow) We acquired the Black Widow prospect at a federal offshore Gulf lease sale in March 1997. We operate and have a 69% working interest in this project, which is located in the Gulf approximately 130 miles south of New Orleans, Louisiana at a water depth of approximately 1,850 feet. In early 1998, we drilled a successful exploration well on the prospect. We commenced production in the fourth quarter of 2000 via subsea tieback to an existing platform, and the field has produced through December 31, 2002 net 22.3 Bcfe. Estimated remaining net proved reserves from Black Widow are approximately 10.1 Bcfe, 87.6% of which is oil.

Viosca Knoll 917 (Swordfish) Mariner entered into a farmout agreement with BP (Amoco) in September 2001 to drill the Swordfish prospect. We operate and have a 15% working interest in this project, which is located in the deepwater Gulf of Mexico 105 miles southeast of New Orleans, Louisiana in water depths that range from 4,200 feet. In November and December of 2001, Mariner drilled two successful exploration wells on the prospect. Estimated net proved reserves for the Swordfish prospect are 9.9 Bcfe. First production is anticipated to commence in the second quarter of 2004.

Mississippi Canyon 322 (Crater Lake) Mariner generated and acquired the Crater Lake prospect at a federal sale in March of 1998. Mariner has a 40% working interest in this Walter Oil & Gas operated project, which is located in the deepwater Gulf of Mexico 75 miles southeast of New Orleans, Louisiana in a water depth of 700 feet. In May of 2001, Walter Oil and Gas drilled a successful exploration well and a successful appraisal that were later completed. First production from the initial discovery well began February 2002. Production from the second well will begin upon depletion of the initial well. The field has produced through December 31, 2002 net 1.0 Bcfe with the estimated net proved remaining reserves from Crater Lake at 3.8 Bcfe.

South Timbalier 316 (Roaring Fork) Mariner entered into a farmout agreement with Westport and Samedan in October 2001 to participate in the drilling of the Roaring Fork prospect. Mariner has a 20% working interest in this Westport operated project, which is located in the Gulf of Mexico 135 miles south of New Orleans, Louisiana in a water depth of 450 feet. Westport drilled a successful exploration well on the prospect followed by two successful appraisal wells. The estimated net proved reserves for the Roaring Fork prospect are 15.5 Bcfe. First production is anticipated to commence in the fourth quarter of 2003.

Brazos A-105 We generated the Brazos A-105 prospect and own a 12.5% working interest in this Unocal-operated property, which commenced production in January 1993. Five wells exploit a single gas reservoir. No additional wells are currently anticipated. The field has produced 28.5 Bcfe net to us from its inception through December 31, 2002. The field has estimated remaining net proved reserves of 4.3 Bcfe as of December 31, 2002, 99% of which is natural gas.

PERMIAN BASIN OF WEST TEXAS

Spraberry Aldwell Unit. We acquired our interest in the Spraberry Aldwell Unit, located in Reagan County, Texas, in 1985. The 18,250-acre unit is located in the heart of the Spraberry Trend southeast of Midland, Texas and has produced oil since 1949. We operate the unit and own working interests in individual wells ranging from approximately 33% to 84%. We initiated an infill drilling program in 1987 innovatively commingling the unitized Spraberry formation with the non-unitized Dean formation. To date, 82 infill wells have been drilled resulting in 82

productive wells. Currently, there are a total of 91 producing wells in the unit. With Mariner having initially contracted 15 infill drilling wells for 2003. Plans are to drill over the next two to four years, the remaining 98 Proved Undeveloped Infill wells. Average cost to drill an Infill Spraberry Well is approximately $400,000(gross). We estimate that the field's remaining net proved reserves as of December 31, 2002 is 65.1 Bcfe. We believe that the field's potential for continued economic oil production exceeds 40 years.

(ii) DISPOSITION OF PROPERTIES

We periodically evaluate and, when appropriate, sell certain of our producing properties that we consider to be marginally profitable or outside of our areas of concentration. We also consider the sale of discoveries that are not yet producing when we believe we can obtain acceptable returns on our investment without holding the investment through depletion. Such sales enable us to maintain financial flexibility, reduce overhead and redeploy the proceeds to activities that we believe have a higher potential financial return. No property dispositions of producing properties were made during the three years ending December 31, 2002. However, in 2000, 2001 and 2002 we sold a 20% gross interest in our Devils Tower project for $29 million, a 30% gross interest in our Devils Tower project and 50% interest in our Aconcagua project for $39.5 million and $51 million respectively and a 25% working interest in the Falcon project for $52.3 million. In March of 2003, we sold our remaining 25% working interest in Falcon and Harrier for $121.6 million. See "Recent Events" above.

(iii) TITLE TO PROPERTIES

Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. We do not believe that any of these burdens materially interferes with the use of such properties in the operation of our business.

We believe that we have satisfactory title to or rights in all of our producing properties. As is customary in the oil and natural gas industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. Title investigation is made, and title opinions of local counsel are generally obtained, only before commencement of drilling operations. We believe that title issues generally are not as likely to arise on offshore oil and gas properties as on onshore properties.

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(f) PRODUCTION

The following table presents certain information with respect to oil and natural gas production attributable to our properties, average sales price received and expenses per unit of production during the periods indicated.

	YEAR ENDING DECEMBER 31,		
	2002	2001	2
PRODUCTION:			
Oil (MMbbls)	1.7	3.0	
Natural gas (Bcf)	29.6	18.8	
Natural Gas equivalent (Bcfe)	39.8	36.7	
AVERAGE REALIZED SALES PRICE PER UNIT (EXCLUDING EFFECTS OF HEDGING):			
Oil ($/Bbl)	$21.60	$22.41	$2
Natural gas ($/Mcf)	3.35	4.86	
Natural Gas equivalent ($/Mcfe)	3.41	4.31	
AVERAGE REALIZED SALES PRICE PER UNIT (INCLUDING EFFECTS OF HEDGING):			
Oil ($/Bbl)	$22.85	$23.22	$2
Natural gas ($/Mcf)	4.03	4.57	
Natural Gas equivalent ($/Mcfe)	3.97	4.22	

EXPENSES ($/MCFE):			
Lease operating	$ 0.65	$ 0.55	$
Transportation	0.26	0.33	
General and administrative, net (1)	0.19	0.25	
Depreciation, depletion and amortization	1.78	1.73	
CASH MARGIN ($/MCFE) (2)	$ 2.66	$ 2.86	$

(1) Net of overhead reimbursements received from other working interest owners and amounts capitalized under the full cost accounting method.

(2) Average equivalent gas sales price (including the effects of hedging prior to de-designation as a hedge), minus lease operating and gross general and administrative expenses.

(g) PRODUCTIVE WELLS

The following table sets forth the number of productive oil and gas wells in which we owned a working interest at December 31, 2002:

	TOTAL PRODUCTIVE WELLS	
	GROSS	NET
Oil	88	61.6
Gas	49	8.9
Total	137	70.5

Productive wells consist of producing wells and wells capable of production, including gas wells awaiting pipeline connections. We have six wells that are completed in more than one producing horizon; those wells have been counted as single wells.

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(h) ACREAGE

The following table sets forth certain information with respect to the developed and undeveloped acreage as of December 31, 2002.

	DEVELOPED ACRES(1)		UNDEVELOPED ACRES(2)	
	GROSS	NET	GROSS	NET
Texas (Onshore)	18,337	12,300	282	117
Other states (Onshore)	671	212	574	126

Offshore	307,325	89,367	400,882	192,572
Total (3)	326,333	101,879	401,738	192,815

(1) Developed acres are acres spaced or assigned to productive wells.

(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

(3) Prior to the sale of our remaining 25% working interest in the Falcon and Harrier discoveries and their surrounding blocks.

(i) DRILLING ACTIVITY

Certain information with regard to our drilling activity during the years ended December 31, 2002, 2001 and 2000 is set forth below.

	YEAR ENDING DECEMBER 31,					
	2002		2001		2000	
	GROSS	NET	GROSS	NET	GROSS	NET
EXPLORATORY WELLS:						
Producing	2	1.08	7	2.48	1	0.40
Dry	4	1.60	4	1.50	3	2.08
Total	6	2.68	11	3.98	4	2.48
DEVELOPMENT WELLS:						
Producing	13	7.93	7	2.40	2	0.45
Dry	0	0.00	1	0.33	--	--
Total	3	7.93	8	2.73	2	0.45
TOTAL WELLS:						
Producing	15	9.01	14	4.88	3	0.85
Dry	4	1.60	5	1.83	3	2.08
Total	9	10.61	19	6.71	6	2.93

(j) MARKETING, CUSTOMERS AND HEDGING ACTIVITIES

We market substantially all oil and gas production from properties we operate and properties operated by others where our interest is significant. The majority of our natural gas, oil and condensate production is sold to a variety of purchasers under short-term (less than 12 months) contracts at market-sensitive prices. As to gas produced from the Spraberry Aldwell Unit, we have a long-term agreement for the sale and processing of such gas on terms that we believe to be competitive. The following table lists customers accounting for more than 10% of our total revenues for the year indicated.

CUSTOMER	PERCENTAGE OF TOTAL REVENUES FOR THE YEAR ENDING DECEMBER 31, 2002	2001	2000
Bridgeline Gas Distributing Company..........	42%	--	--
Conoco Inc...	14%	--	--
Duke Energy......................................	9%	14%	16%
Enron North America and affiliates (An affiliate of the Company)..................	--	32%	49%
Genesis Crude Oil LP............................	4%	24%	--

On June 28, 2002 the Company commenced price risk activities with a third party. These activities are intended to manage the Company's exposure to fluctuations in commodity prices for natural gas and crude. As of December 31, 2002, the Company had the following fixed price swaps outstanding.

TIME PERIOD	NOTIONAL QUANTITIES	FIXED PRICE	DECEMBER 3 FAIR V (millio Gain/(L
CRUDE OIL (MBbl)			
January 1 - December 31, 2003			
Fixed Price Swap	548	$24.02	$ (1.8
Fixed Price Swap	183	$24.81	(0.4
NATURAL GAS (MMbtu)			
January 1 - December 31, 2003			
Fixed Price Swap	730	$ 3.54	(7.5
Fixed Price Swap	730	$ 3.60	(7.1
			$(16.8

The Company has reviewed the financial strength of counterparts to these transactions and believes credit risk to be minimal. As of December 31, 2002 the Company had on deposit, classified as restricted cash, $15.2 million with a third party for collateral. This collateral included $5.8 million in initial margin in cash and $16.7 million in mark-to-market exposure which is recorded as a liability with an offset in accumulated other comprehensive income. Initial margin decreases as contracts settle.

As a result of increasing natural gas prices, in January and February of 2003, the Company unwound, through the purchase of counter positions, all natural gas swap contracts for the months of February through October 2003 locking in a loss of $23.2 million. This loss will be settled over the original contract period.

Subsequent to their unwinding the Company will have approximately 24% of 2003 production subject to hedges. Mark to market value changes approximately $8.6 million for every 10% overall change in commodity prices.

The following table sets forth the results of hedging transactions during the periods indicated that were made with non-Enron related parties.

	DECEMBER 31,	
	2002	2001
NATURAL GAS	--	--
Quantity hedged (Mmbtu)		
Increase (Decrease) in Natural Gas Sales (in thousands)	--	--
CRUDE OIL		
Quantity hedged (MBbls)	169	--
Increase (Decrease) in Crude Oil Sales (in thousands)	$(325)	--

(k) COMPETITION

We believe that the locations of our leasehold acreage, our exploration, drilling and production capabilities, and our experience generally enable us to compete effectively. However, our competitors include major integrated oil and natural gas companies and numerous independent oil and natural gas companies, individuals and drilling and income programs. Many of our larger competitors possess and employ financial and personnel resources substantially greater than those available to us. Such companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and

purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to discover reserves in the future is dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, there is substantial competition for capital available for investment in the oil and natural gas industry.

(l) ROYALTY RELIEF

The Outer Continental Shelf Deep Water Royalty Relief Act (the "RRA"), signed into law on November 28, 1995, provides that all tracts in the Gulf of Mexico west of 87 degrees, 30 minutes West longitude in water more than 200 meters deep offered for bid within five years of the RRA will be relieved from normal federal royalties as follows:

WATER DEPTH	ROYALTY RELIEF
200-400 meters.........................	no royalty payable on the first 105 Bcfe produced
400-800 meters.........................	no royalty payable on the first 315 Bcfe produced
800 meters or deeper...................	no royalty payable on the first 525 Bcfe produced

The RRA also allows mineral interest owners the opportunity to apply for royalty relief for new production on leases acquired before the RRA was enacted. If the United States Minerals Management Service ("MMS") determines that new production would not be economical without royalty relief, then a portion of the royalty may be relieved to make the project economical.

The impact of royalty relief is significant, as normal royalties for leases in water depths of 400 meters or less is 16.7%, and normal royalties for leases in water depths greater than 400 meters is 12.5%. Royalty relief can substantially improve the economics of projects in deep water. In the event that prices exceed certain prescribed thresholds royalty relief is suspended. In 2000 and 2001, our Pluto, Black Widow, Garden Banks 179 and King Kong projects qualified for royalty relief; however, natural gas prices exceeded the thresholds. Consequently, we have been required to pay royalties on natural gas for both 2000 and 2001. Natural gas prices did not exceed threshold for 2002. We are currently disputing the MMS right to suspend royalty relief on certain blocks solely because of the threshold prices and consequently filed an administrative appeal. We have accrued $5.5 million related to this obligation to provide for the event that we lose our appeal.

(m) REGULATION

Our operations are subject to extensive and continually changing regulation affecting the oil and natural gas industry. Many departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding on the oil and natural gas industry and its individual participants. The failure to comply with such rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability. We do not believe that we are affected in a significantly different manner by these regulations than are our competitors.

(i) TRANSPORTATION AND SALE OF NATURAL GAS

The FERC (Federal Energy Regulatory Commission) regulates interstate natural gas pipeline transportation rates and service conditions, which affect the marketing of gas produced by us and the revenues received by us for sales of such natural gas. In 1985, the FERC adopted policies that make natural gas transportation accessible to natural gas buyers and sellers on an open-access, non-discriminatory basis. The FERC issued Order No. 636 on April 8, 1992, which, among other things, prohibits interstate pipelines from tying sales of gas to the provision of other services and requires pipelines to "unbundle" the services they provide. This has enabled buyers to obtain natural gas supplies from any source and secure independent delivery service from the pipelines. All of the interstate pipelines subject to FERC's jurisdictions are now operating under Order No. 636 open access tariffs. On July 29, 1998, the FERC issued a Notice of Proposed Rulemaking regarding the regulation of short term natural gas transportation services. In a related initiative, FERC issued a Notice of Inquiry on July 29, 1998 seeking input from natural gas industry players and affected entities regarding virtually every aspect of the regulation of interstate natural gas transportation services. As a result, the FERC issued Order No. 637 (final rule on February 9, 2000) amending its transportation regulation in response to the growing

development of more competitive markets for natural gas and the transportation of natural gas. Order No. 637 revises the regulatory framework to improve the efficiency of the natural gas market and provide captive customers with the opportunity to reduce their cost of holding long-term pipeline capacity. The rate revises the FERC's pricing policy to enhance market efficiency for short term released capacity and permit pipelines to file for peak and off-peak and term differentiated rate structures. Order No. 637 further improves the Commission's reporting requirements and permits more effective monitoring of the natural gas market.

Additional proposals and proceedings that might affect the natural gas industry are considered from time to time by Congress, the FERC, state regulatory bodies and the courts. We cannot predict when or if any such proposals might become effective or their effect, if any, on our operations. The natural gas industry historically has been closely regulated; thus, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue indefinitely into the future.

(ii) REGULATION OF PRODUCTION

The production of oil and natural gas is subject to regulation under a wide range of state and federal statutes, rules, orders and regulations. State and federal statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. Most states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and the regulation of the spacing, plugging and abandonment of wells. Many states also restrict production to the market demand for oil and natural gas and several states have indicated interest in revising applicable regulations. The effect of these regulations is to limit the amount of oil and natural gas we can produce from our wells and the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to production and sale of crude oil, natural gas and gas liquids within its jurisdiction.

Most of our offshore operations are conducted on federal leases that are administered by the MMS and are required to comply with the regulations and orders promulgated by MMS. Among other things, we are required to obtain prior MMS approval for our exploration, development and production plans for these leases. The MMS regulations also establish construction requirements for production facilities located on our federal offshore leases and govern the plugging and abandonment of wells and the removal of production facilities from these leases. Under certain circumstances, the MMS could require us to suspend or terminate our operations on a federal lease.

In addition, a portion of our Sandy Lake Properties is located within the boundaries of the Big Thicket National Preserve (the "BTNP"), which is under the jurisdiction of the United States National Park Service (the "NPS"). Our operations within the BTNP must comply with regulations of the NPS. In general, these regulations require us to obtain NPS approval of a plan of operations for any activity within the BTNP or to demonstrate that a waiver of a plan of operations is appropriate. Compliance with these regulations increases our cost of operations and may delay the commencement of specific operations.

(iii) ENVIRONMENTAL REGULATIONS

GENERAL. Various federal, state and local laws and regulations governing the discharge of materials into the environment, or otherwise relating to the protection of the environment, affect our operations and costs. In particular, our exploration, development and production operations, activities in connection with storage and transportation of crude oil and other liquid hydrocarbons and use of facilities for treating, processing or otherwise handling hydrocarbons and wastes therefrom are subject to stringent environmental regulation. As with the industry generally, compliance with existing regulations increases our overall cost of business. Such areas affected include unit production expenses primarily related to the control and limitation of air emissions and the disposal of produced water, capital costs to drill exploration and development wells resulting from expenses primarily related to the management and disposal of drilling fluids and other oil and gas exploration wastes and capital costs to construct, maintain and upgrade equipment and facilities.

SUPERFUND. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as "Superfund", imposes liability, without regard to fault or the legality of the original act, on certain classes of persons that contributed to the release of a "hazardous substance" into the environment. These persons include the "owner" or "operator" of the site and companies that disposed or arranged for the disposal of the hazardous substances found at the site. CERCLA also authorizes the Environmental Protection Agency and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. In the course of its ordinary operations, we may generate waste that may fall within CERCLA's definition of a "hazardous substance". We may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which such wastes have been disposed.

We currently own or lease, and have in the past owned or leased, numerous properties that for many years have been used for the exploration and production of oil and gas. Although we have 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 us or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose actions with respect to the treatment and disposal or release of hydrocarbons or other wastes were not under our control. These properties and wastes disposed thereon may be subject to CERCLA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial plugging operations to prevent future contamination.

OIL POLLUTION ACT OF 1990. The Oil Pollution Act of 1990 (the "OPA") and regulations thereunder impose liability on "responsible parties" for damages resulting from crude oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. Liability under the OPA is strict, joint and several, and potentially unlimited. A "responsible party" includes the owner or operator of an onshore facility and the lessee or permittee of the area in which an offshore facility is located. The OPA also requires the lessee or permittee of the offshore area in which a covered offshore facility is located to establish and maintain evidence of financial responsibility in the amount of $35 million ($10 million if the offshore facility is located landward of the seaward boundary of a state) to cover liabilities related to a crude oil spill for which such person is statutorily responsible. The amount of required financial responsibility may be increased above the minimum amounts to an amount not exceeding $150 million depending on the risk represented by the quantity or quality of crude oil that is handled by the facility. The MMS has promulgated regulations that implement the financial responsibility requirements of the OPA. A failure to comply with the OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions. We are not aware of any action or event that would subject us to liability under the OPA and we believe that compliance with the OPA's financial responsibility and other operating requirements will not have a material adverse effect on us.

CLEAN WATER ACT. The Federal Water Pollution Control Act of 1972, as amended (the "Clean Water Act"), imposes restrictions and controls on the discharge of produced waters and other oil and gas wastes into navigable waters. These controls have become more stringent over the years, and it is possible that additional restrictions will be imposed in the future. Permits must be obtained to discharge pollutants into state and federal waters. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and gas industry into certain coastal and offshore water. The Clean Water Act provides for civil, criminal and administrative penalties for unauthorized discharges for oil and other hazardous substances and imposes liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. Comparable state statutes impose liabilities and authorize penalties in the case of an unauthorized discharge of petroleum or its derivatives, or other hazardous substances, into state waters. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

RESOURCES CONSERVATION RECOVERY ACT. The Resource Conservation Recovery Act ("RCRA") is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements, and liability for failure to meet such requirements, on a person who is either a "generator" or "transporter" of hazardous waste or an "owner" or "operator" of a hazardous waste treatment,

storage or disposal facility. At present, RCRA includes a statutory exemption that allows most crude oil and natural gas exploration and production waste to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA's requirements because our operations generate minimal quantities of hazardous wastes. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes crude oil and natural gas exploration and production wastes from regulation as hazardous waste. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us to incur increased operating expenses.

(n) EMPLOYEES

As of December 31, 2002, we had 43 full-time employees. Our employees are not represented by any labor unions. We consider relations with our employees to be satisfactory. We have never experienced a work stoppage or strike.

(o) Our internet website is www.mariner-energy.com. While our website includes a link to EDGAR, we do not otherwise make our Exchange Act reports available on our website. [Our Exchange Act reports are available free of charges by request to Mike Wichterich at mwichterich@mariner-energy.com.

ITEM 3. LEGAL PROCEEDINGS

MMS APPEAL - Mariner operates numerous properties in the Gulf of Mexico. Three of such properties were leased from the Mineral Management Service subject to the 1996 Royalty Relief Act. This Act relieved the obligation to pay royalties on certain predetermined leases until a designated volume is produced. These three leases contained language, which limited royalty relief if commodity prices exceeded predetermined levels. Beginning in January 2000 commodity prices exceeded the predetermined levels. Management believes the MMS did not have the authority to set pricing limits and the Company has filed an administrative appeal with the MMS and has withheld royalties regarding this matter. The Company has recorded a liability for 100% of the exposure on this matter which on December 31, 2002 was $5.5 million.

In the ordinary course of business, we are a claimant and/or a defendant in various legal proceedings, including proceedings as to which we have insurance coverage, in which the exposure, individually and in the aggregate, is not considered material to us.

Also see further description under "Enron" in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" regarding matters that could impact the Company operations.

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

None.

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PART II

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

There is no established public trading market for our common stock, our only class of equity securities.

Equity Compensation Plan Information

The following table provides information about our shares of Common Stock that may be issued upon the exercise of options under our stock compensation plan as of December 31, 2002.

	Number of securities to be issued upon exercise of outstanding options	Weighted average exercise price of outstanding options	Nu rem fu e secu

Plan Category		
Equity compensation plans approved by shareholders	-	-
Equity compensation plans, not approved by shareholders	1,926,468	9.47

See Part III, Item 13. "Certain Relationships and Related Party Transactions" related to common stock ownership and other entities related to registrant.

ITEM 6. SELECTED FINANCIAL DATA

The information below should be read in conjunction with Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the financial statements included in Item 8 of this report. The following table sets forth selected financial data for the periods indicated.

(ALL AMOUNTS IN MILLIONS)

	YEAR ENDING DECEMBER 31,			
STATEMENT OF OPERATIONS DATA:	2002	2001(1)	2000	1999
Total revenues...........................	$158.2	$155.0	$121.1	$ 54.5
Lease operating expenses.................	26.1	20.1	17.2	11.5
Transportation...........................	10.5	12.0	7.8	2.0
Depreciation, depletion and amortization..	70.8	63.5	56.8	32.1
Impairment of oil and gas properties......	-	-	-	-
Impairment of Enron related receivables...	3.2	29.5	-	-
Provision for Litigation.................	-	-	-	-
General and administrative expenses.......	7.7	9.3	6.5	5.4
Operating income (loss).............	39.9	20.6	32.8	3.5
Interest income..........................	0.4	0.7	0.1	-
Interest expense.........................	(10.3)	(8.9)	(11.0)	(13.5)
Income (loss) before income taxes....	30.0	12.4	21.9	(10.0)
Provision for income taxes...............	-	-	-	-
Net income (loss)...................	$ 30.0	$ 12.4	$ 21.9	$(10.0)
CAPITAL EXPENDITURE AND DISPOSAL DATA:				
Exploration, including leasehold/seismic..	$ 40.4	$ 66.3	$ 46.7	$ 24.0
Development and other....................	65.7	98.2	61.4	57.5
Proceeds from property conveyances........	(52.3)	(90.5)	(29.0)	(19.8)
Total capital expenditures net of proceeds from property conveyances	$ 53.8	$ 74.0	$ 79.1	$ 61.7
BALANCE SHEET DATA (AT END OF PERIOD):				
Oil and gas properties, net, at full cost.	$286.0	$290.6	$287.8	$263.6
Total assets.............................	360.2	363.9	335.4	297.5

Long-term debt, less current maturities...	99.8	99.8	129.7	167.3
Stockholder's equity.....................	170.1	180.1	141.9	65.0

(1) Historically we have recorded all derivative transactions utilizing hedge accounting treatment. On January 1, 2001 we adopted Financial Accounting Standard No. 133 "Accounting for Derivative Instruments and Hedging Activities". In addition, beginning on December 2, 2001, due to the Enron bankruptcy, we ceased hedging accounting treatment. In 2002 we began hedging with a new third party.

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

(a) INTRODUCTION

The following discussion is intended to assist in an understanding of our financial position and results of operations for each of the three years in the period that began January 1, 2000 and ended December 31, 2002. This discussion should be read in conjunction with the information contained in the financial statements included elsewhere in this annual

report. All statements other than statements of historical fact included in this annual report, including, without limitation, statements contained in this "Management's Discussion and Analysis of Financial Condition and Results of Operations" regarding our financial position, business strategy, plans and objectives of management for future operations and industry conditions, are forward-looking statements. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct.

(b) GENERAL

We are an independent oil and natural gas exploration, development and production company with principal operations in the Gulf of Mexico and along the U.S. Gulf Coast. Our strategy is to profitably increase reserves, production and cash flow primarily through the drillbit.

During 2002 we:

- drilled 6 exploratory wells, with 2 successes, in the Gulf of Mexico;

- drilled successful appraisal wells on our Falcon and Roaring Fork prospects;

- commenced first production on our King Kong/Yosemite project;

- sold half of our 50% working interest in Falcon project, with proceeds from these sales being used to pay off our Revolving Credit Facility;

- added proved reserves of 39.8 Bcfe, which were approximately 100% of our 2002 production and resulted in proven reserves of 202 Bcfe net of the 33.3 Bcfe in attributable to the 2002 sold working interest in our Falcon project.

We anticipate capital expenditures for 2003, before capitalized indirect costs and proceeds from property conveyances, to be approximately $103 million of which $41 million is expected to be used for leasehold acquisition, seismic data and exploration drilling and $62 million for development expenditures. This is approximately equal to our 2002 capital expenditures of approximately $97.3 million, before capitalized indirect costs and proceeds from property conveyances of $52.3 million. We expect to fund our capital expenditures by a combination of internally generated cash flow and proceeds from property conveyances, including the recently announced sale of the remaining interest in our Falcon Corridor project.

Our results of operations may vary significantly from year to year based on the factors discussed above and on other factors such as exploratory and development drilling success, curtailments of production due to workover and recompletion activities and the timing and amount of reimbursement for overhead costs we receive from co-owners. Therefore, the results of any one year may not be indicative of future results.

(c) RECENT EVENTS

On March 19, 2003, with bids totaling $3.9 million net to us, we were the apparent high bidder solely or with industry partners, on 11 out of 11 blocks on which we and our partners submitted bids in the Central Gulf of Mexico Oil and Gas Lease Sale 185 held on that date. Each of the blocks is in water depths ranging from approximately 20 feet to 1,500 feet. Mariner has a 100% working interest in five of the blocks and a 50% working interest in six blocks.

In January 2003 we made a deepwater Gulf of Mexico Discovery at "Harrier", East Breaks 759, and a shelf Gulf of Mexico discovery at Vermillion 144. Harrier was drilled in 4,100 feet of water to a total measured depth of 9,510 feet and encountered 315 net feet of gas pay. Mariner holds a 25% working interest. Vermilion 144 was drilled in 87 feet of water to a total measured depth of 16,522 feet and encountered 90 net feet of pay. Mariner is operator with a 42% working interest. First production is expected in June 2003.

In March 2003, we sold our remaining 25% working interest in our Falcon and Harrier discoveries and surrounding blocks, located in East Breaks area in the western Gulf of Mexico, for $121.6 million. We retained a 4 1/4 percent overriding royalty interest on seven non-producing blocks. The proceeds from the sale are expected to be used for debt reduction, capital expenditures, and other corporate purposes. At December 31, 2002, the Falcon project had 33.3 Bcfe assigned as proven oil and gas reserves to our interest.

(d) ENRON-CONTROL RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

ENRON BANKRUPTCY - Commencing on December 2, 2001, Enron Corp. ("Enron") and certain of its affiliates, including Enron North America Corp. ("ENA"), filed voluntary petitions for bankruptcy protection. We have been informed that of our various direct or indirect owners, only Enron and ENA are debtors in the bankruptcy. We do not know at this time if any other owners will seek bankruptcy protection or what effect, if any, this may have on the ownership of Mariner Energy LLC which owns 100% of Mariner Holdings, Inc. (our direct parent) or on Joint Energy Development Investments Limited Partnership ("JEDI"), which owns approximately 96% of the issued and outstanding equity of Mariner Energy LLC. Enron is the parent of ENA, and an affiliate of ENA is the general partner of JEDI. JEDI is 100% owned by Enron and affiliates of ENA. Accordingly, Enron may be deemed to control JEDI, Mariner Energy LLC, Mariner Holdings and us. Additionally, five of the Company's directors are officers of Enron or affiliates of Enron. Because of these various potentially conflicting interests, ENA, the Company, JEDI and the minority shareholders of Mariner Energy LLC have entered into an agreement that is intended to make clear that

Enron and its affiliates have no duty to make business opportunities available to the Company.

Mariner Energy LLC's only asset is 100% of the common stock of Mariner Holdings, Inc., our direct parent. The only asset of Mariner Holdings is 100% of the common shares of Mariner.

Management cannot predict with certainty what impact Enron's bankruptcy may have on us. However, it does believe that our assets and liabilities will not become part of the Enron estate in bankruptcy. Although JEDI owns 96% of Mariner Energy LLC's common shares, we, as a separate corporation own or lease the assets used in its business and our management, separate from Enron, is responsible for our day-to-day operations. Contractual provisions restrict Enron access to our assets. We maintain our own accounting system as well as separate debt ratings. We maintain our own separate and complete cash management system and finance its operations separately from Enron, on both a short-term and long-term basis. We file a consolidated tax return with Mariner Energy LLC.

Notwithstanding the above, we may have potential exposure to certain liabilities and asset impairments as a result of Enron's bankruptcy. Portions following Enron-related disclosures are based on discussions with Enron's legal advisors and management, including members of our Board of Directors. Although our management has implemented with Enron's legal advisor and management a systematic method of identifying Enron matters which may have a material impact on us, management cannot provide any assurance as the completeness or accuracy of the information provided by or on behalf of Enron.

ORGANIZATION AND OWNERSHIP OF THE COMPANY - Through March 31, 1996, Hardy Oil & Gas USA Inc. (the "Predecessor Company") was a wholly-owned subsidiary of Hardy Holdings Inc., which is a wholly-owned subsidiary of Hardy Oil & Gas Plc ("Hardy Plc"), a company incorporated in the United Kingdom. Pursuant to a stock purchase agreement dated April 1, 1996, JEDI and ENA, together with members of management of the Predecessor Company, formed Mariner Holdings, Inc. ("Mariner Holdings"). Mariner Holdings then purchased from Hardy Holdings Inc. all of the issued and outstanding stock of the Predecessor Company for a purchase price of approximately $185.5 million (the "Acquisition"). After the Acquisition, the name of the Predecessor Company was changed to Mariner Energy, Inc. In October 1998, JEDI and other shareholders exchanged all of their common shares of Mariner Holdings, the Company's direct parent, for an equivalent ownership percentage in common shares of Mariner Energy LLC. Mariner Energy LLC owns 100% of Mariner Holdings.

The following chart represents our current ownership structure and affiliation with Enron entities.

```
------------------                                          ------------------
   Enron North     ____________________100%__________________    Enron Corp.
  America Corp.    _____                                      ------------------
------------------     |                                               |
        |              |                                               |
        |              |                                               |
        |              |                                               |
        |              |        ------------------                     |
        |              |________   JILP-LP, Inc.                       |
        |                       ------------------                     |
        |                                |                             |
        |                                |  (Asset Specific)           |
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         |                               |                           |
         |                       ------------------                  |
         |                            Ponderosa                      |
         |                            Assets LP                     LP
         |                       ------------------                  |
         |                               |                           |
         |                               |  (Limited Partnership)    |
         |                               |                           |
------------------               ------------------                  |
   Enron Capital  _____GP_______  Enron Capital                      |
       Corp.           _________  Management LP                      |
------------------      |        ------------------                  |
                        |                |                           |
                        |                GP                          |
                        |                |                           |
------------------      |        ------------------                  |
   Enron Capital  _____|            Joint Energy                     |
 Management, LLC  ____SLP_______     Development   ___________________|
------------------               Investments (JEDI)
                                 ------------------
                                         |
                                        96%
                                         |
                                 ------------------            ------------------
                                      Mariner      _____4%_____  Employees and
                                    Energy, LLC                 Former Employees
                                 ------------------            ------------------
                                         |
                                       100%
                                         |
                                 ------------------
                                      Mariner
                                  Holdings, Inc.
                                 ------------------
                                         |
                                       100%
                                         |
                                 ------------------
                                      Mariner
                                    Energy, Inc.
                                 ------------------
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Subsequent to the Acquisition, Mariner Energy LLC, Mariner Holdings and Mariner have each entered into various financing and operating transactions with affiliates. In addition the Company may have from time to time engaged in various commercial transactions and have various commercial relationships with Enron and certain affiliates of Enron, such as holding and exploring, exploiting and developing joint working interests in particular prospects and properties and entering into other oil and gas related or financial transactions. Certain of the Company's third-party debt instruments and arrangements restrict the Company's ability to engage in transactions with its affiliates, but those restrictions are subject to significant exceptions. The Company believes that its current agreements with Enron and its affiliates are, and anticipates that any future agreements with Enron and its affiliates will be, on terms no less favorable to the Company than would be obtained in an agreement with a third party. Below is a summary of key transactions between the Company and affiliate entities.

MARINER ENERGY LLC

ENA Affiliate Term Loan - In March 2000, Mariner Energy LLC established an unsecured term loan with ENA to repay amounts outstanding under various affiliate credit facilities at Mariner Energy LLC and Mariner and to provide additional working capital. The additional working capital of $55 million was contributed to Mariner in 2000. The loan bears interest at 15%, which interest accrues and is added to the loan principal. Repayment of the balance of loan principal and accrued interest, which was approximately $164.4 million as of December 31, 2002, is due March 20, 2004. In conjunction with the loan agreement, two five-year warrants were issued to ENA providing the right to purchase up to 900,000 of common shares of Mariner Energy LLC for $0.01 per share.

Covenants in Mariner's Senior Subordinated Notes restrict the funds of Mariner that can be distributed to Mariner Energy LLC. Accordingly, Mariner Energy LLC is restricted in its ability to repay the unsecured Term Loan or to distribute earnings to its shareholders. In the event Mariner Energy LLC is unable to restructure or extend the maturity of its obligations prior to March 2004 it would either default under the Term Loan or be forced to sell its interest in Mariner or cause Mariner to sell a substantial portion of its assets to repay any outstanding Senior Subordinated Notes so that it could distribute any remaining cash proceeds to Mariner Energy LLC to be used to repay the Term Loan.

We have been informed by Enron's legal advisors and management that the Term Loan and warrants were transferred from ENA to an ENA affiliate, which affiliate is part of a finance structure formed by ENA. Because debt obligations of the finance structure are in default and ENA therefore does not have complete control over decisions made by the ENA affiliate, it may be difficult for Mariner Energy LLC to obtain any consents, waivers or amendments needed from the ENA affiliate in connection with the Term Loan or the warrants.

MARINER HOLDINGS, INC.

1998 Equity Investment - In June 1998, Mariner Holdings issued additional equity to its existing shareholders, including JEDI, for approximately $14.58 per share, for a net investment of $28.8 million, all of which was contributed to Mariner. Mariner Holdings paid approximately $1.2 million as a structuring fee, on a pro rata basis, to existing shareholders participating in this transaction. Approximately $1 million of this fee was paid to ECT Securities Limited Partnership.

MARINER ENERGY, INC.

Oil and Gas Production Sales to ENA or Affiliates - During the three years ending December 31, 2002, 2001 and 2000, sales of oil and gas production to ENA or affiliates were $56.4million, $50.2 million and $73.4 million, respectively. These sales were generally made on 1 to 3 month contracts. At the time ENA filed its petition for bankruptcy protection, the Company immediately ceased selling its physical production to ENA, however, we continued to sell our production to Bridgeline which ENA owned a minority interest. All amounts sold to this party have been collected. As of December 31, 2002, we had an outstanding receivable for $3 million from ENA. This amount was not paid as scheduled and is still outstanding. Mariner has submitted a proof of claim to the bankruptcy court for amounts owed to it by ENA. The Company has estimated 100% of this balance is uncollectible and has recorded a full allowance and related expense.

Management Activities - We engage in price risk management activities from time to time. These activities are intended to manage our exposure to fluctuations in commodity prices for natural gas and crude oil. We primarily utilize price swaps and costless collars as a means to manage such risk. Historically, all of our hedging contracts were with ENA. As a result of ENA's bankruptcy, the contracts are currently in default. The November 2001 through April 30, 2002 settlements for oil and gas have not been collected. In addition, on May 14, 2002, we elected under our Master Service Agreement with ENA to terminate all open contracts. The effect of this termination is to fix the nominal value on all remaining contracts on May 14, 2002. Subsequent to this termination, the value of all oil and natural gas unpaid hedge contracts was $7.7 million. We have estimated 100% of this balance is uncollectible and has recorded a full allowance. We have submitted a proof of claims to the bankruptcy court for amounts owed under this agreement. In accordance with Statement of Financial Accounting Standards ("SFAS") No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 137 and No. 138, we have de-designated our contracts effective December 2, 2001 and are recognizing all market value changes subsequent to such de-designation in our earnings. The value recorded up to the time of de-designation and included in Accumulated Other Comprehensive Income ("AOCI"), will reverse out of AOCI and into earnings as the original corresponding production, as hedged by the contracts, is produced. For the year ending December 31, 2002 approximately $23.2 million has reversed out to earnings. As of December 31, 2002, $2.6 million remained in AOCI to be reversed out to earnings.

The following table sets forth the results of hedging transactions during the periods indicated that were made with ENA (all amounts shown are non-cash items):

	YEAR ENDING DE	
	2002	2001
Natural gas quantity hedged (Mmbtu).........................	18,090	17,7
Increase (decrease) in natural gas sales (thousands).........	$20,413	$(5,5
Crude oil quantity hedged (MBbls)...........................	446	7
Increase (decrease) in crude oil sales (thousands)...........	$ 2,787	$ 2,3

Supplemental Affiliate Data - provided below is a supplemental balance sheet and income statement for affiliate entities:

BALANCE SHEET DATA	DECEMBER 31, 2002 AMOUNTS (IN MILLIONS)	DE
	TOTAL	

RELATED PARTY RECEIVABLE:			
Derivative Asset	$ -		$ 2.5
Settled Hedge Receivable	-		0.4
Oil and Gas Receivable	8.2	8.2	0.3
ACCRUED LIABILITIES:			
Transportation Contract	-	-	0.9
Service Agreement	0.6	1.5	0.3
STOCKHOLDER'S EQUITY:			
Common Stock	$ .001	-	$ .001
Additional Paid in Capital	$ 227.3		$227.3
Accumulated other Comprehensive Income	$ 2.3	$229.6	$ 25.8

INCOME STATEMENT DATA	YEAR EN DECEMBE 2002
Oil and Gas Sales	$ 56.4
General and Administrative Expenses	0.4
Transportation Expenses	2.7
Unrealized loss and other non-cash derivative instrument adjustments	3.2

As a result of the Enron and ENA bankruptcies, among other implications, we may not be able to obtain credit from banks or trade vendors or enter into hedging arrangements on acceptable terms. To date, our operations have not been materially affected by the bankruptcies; however, our ability to enter into certain transactions including purchase or sale arrangements and to conduct significant capital programs may be affected in the future. Oil and gas sales and the related accounts receivable for the year ending December 31, 2002 relate to sales made to a minority owed affiliate of Enron.

CONTROLLED GROUP LIABILITY

On November 12, 2002, Enron's legal advisors and management informed us that we may be an Enron Corp. Controlled Group Member as defined under the Employee Retirement Income Security Act of 1974 ("ERISA") due to Enron's indirect ownership interest in Mariner Energy LLC. Enron management has not made a final determination if we are in fact a Controlled Group Member. Because of numerous ownership issues within the Enron Group, we are unable to make our own determination as to whether we agree or disagree that we are a Controlled Group Member. In the event we are a Controlled Group Member, we may have potential liability for certain employee benefit plan obligations of Enron discussed below.

Pension Plans - Applicable federal law authorizes the Pension Benefit Guaranty Corporation ("PBGC") to institute proceedings in federal district court for the termination of a pension plan if it determines the plan has failed to comply with minimum funding standards, the plan is or will be unable to pay benefits when due, or the failure to terminate the plan may reasonably be expected to unreasonably increase the possible long-run loss to the PBGC. Federal law also authorizes the sponsor of a pension plan to terminate the plan at a time when the plan is underfunded, subject to PBGC or court approval.

Based on discussions with Enron management, it is our management's understanding that, as of December 31, 2002 the assets of Enron's pension plan (the "Enron Plan") were less than the present value of all accrued benefits by approximately $52 million on a SFAS No. 87 basis and approximately $182 million on a plan termination basis. Further, Enron's management has informed Mariner management that the PBGC has filed claims in the Enron bankruptcy cases. The claims are duplicative in nature, representing unliquidated claims for PBGC insurance premiums (the "Premium Claims") and unliquidated claims for due but unpaid minimum funding contributions (the "Contribution Claims") under the Internal Revenue Code of 1986, as amended (the "Tax Code") 29 U.S.C. Sections 412(a) and 1082 and claims for unfunded benefit liabilities (the "UBL" Claims"). Enron and the relevant sponsors of the defined benefit plans are current on their PBGC premiums and their contributions to the pension plans. Therefore, Enron has valued the Premium Claims and the Contribution Claims at $0. The total amount of the UBL Claims is $305.5 million (including $271 million for the Enron Plan). In addition Enron Management has informed Mariner Management that the PBGC has informally alleged in pleadings filed with the bankruptcy court that the UBL Claim related to the Enron Plan could increase by as much as 100%. PBGC has provided no support (statutory or otherwise) for this assertion and Enron Management disputes the validity of any such claim. Because the Enron Plan is under funded and Enron is in bankruptcy, in certain circumstances the Enron Plan may be terminated and taken control of by the PBGC upon approval of a Federal District Court.

Mariner's employees have not been participants in the Enron Plan. However, upon termination of a pension plan, all of the members of the controlled group of the plan sponsor become jointly and severally liable for the plan are under funding. The PBGC can demand payment from one or more of the members of the controlled group. If payment is not made, a lien in favor of the PBGC automatically arises against all of the assets of that member of the controlled group. The amount of the lien is equal to the lesser of the underfunding or 30% of the aggregate net worth of all of the controlled group members. In addition, if the sponsor of a pension plan does not timely satisfy its minimum funding obligation to the pension plan, once the aggregate missed amounts exceed $1 million, a lien in favor of the plan in the amount of the missed funding automatically arises against the assets of every member of the controlled group. In either case, the PBGC may file to perfect the lien and attempt to enforce it against the assets of members of the Enron Controlled Group. Mariner has been informed by Enron that Enron's management believes that the lien would be subordinate to prior perfected liens on the assets of the member of the Controlled Group. Based on discussions with Enron's management, Mariner's management understands that Enron has made all required contributions to date through October 15, 2002. Enron's management has advised us that it intends to make its next contribution, due in the first quarter of 2003.

Management cannot predict the outcome of the above matters or estimate any potential loss. In addition, if the PBGC did look solely to Mariner to pay any amount with respect to the Enron Plan, Mariner would exercise all legal rights, available to it to defend against such a demand and to recover any contributions from the other solvent members of the Controlled Group. No reserves have been established by Mariner for any amounts related to this issue.

Mariner has also been informed by Enron management that Enron has contacted the PBGC as well as Unsecured Creditors Committee regarding their intention to terminate the Enron Plan, subject to approval by such parties, the bankruptcy court and authorization to fully fund the Enron Plan in accordance with its terms. If approved Enron would fully fund the Enron Plan in accordance with the terms, the plan could be terminated without any liability to Mariner. Enron has also stated that it believes it has the necessary funds to consummate such a termination. In addition to the extent that entities in the Controlled Group are sold prior to termination of the Plan, proceeds of the sale of such entities may be available to satisfy this liability. Enron estimates proceeds from such sale of Enron Control Group entities would far exceed any plan obligations.

Retiree Health Benefits - Under COBRA, if certain retirees of Enron lose coverage under Enron's group health plan due to Enron's bankruptcy proceedings, they would be entitled to elect continuation of their health coverage in a group plan maintained by Enron or a member of its Controlled Group. Mariner's employees have not participated in this plan. Mariner management understands, based on discussions with Enron management, that Enron had provided a plan for retiree health insurance and that the actuarial liability for such coverage was approximately $70 million as of December 31, 2001. Management further understands that to meet its obligation, Enron, at December 31, 2001, had set aside approximately $34 million of assets in a VEBA trust, which may be protected under ERISA from Enron's creditors, leaving an unfunded liability of approximately $36 million.

In the event that Enron terminates its retiree group health plan, the retirees must be provided the opportunity to purchase continuing coverage from Enron's group health plan, if any, or the most appropriate existing group health plan of another member of the Enron Controlled Group. Retirees electing to purchase COBRA coverage would be provided the same coverage that is provided to similarly situated retirees under the appropriate existing plan. Retirees electing to purchase COBRA coverage would be required to pay for the coverage, up to an amount not to exceed 102% of the cost of coverage for similarly situated beneficiaries. Retirees are not required to purchase coverage under COBRA. Retirees may, instead, shop for coverage from third party sources and determine which is the least expensive coverage.

Management cannot predict the outcome of the above matter or estimate any potential loss. However, management believes that in the event Enron terminates coverage, any liability to Mariner associated with the number of retirees that choose to remain under Enron's retiree health plan will not be material. No reserves have been established by Mariner for any amounts related to this issue.

SALE OF ENRON INTEREST IN MARINER

On May 3, 2002, Enron presented to its Unsecured Creditors' Committee a proposal under which certain of Enron's core energy assets, including JEDI's ownership of Mariner Energy LLC, would be separated from Enron's bankruptcy estate and operated prospectively as a new integrated power and pipeline company.

On August 27, 2002, Enron announced that it had commenced a formal sales process for its interests in certain major assets, including JEDI's ownership of Mariner Energy LLC. In its announcement, Enron indicated that it was extending invitations to visit electronic data rooms containing information on 12 of its most valuable businesses, including Mariner, to a broad universe of potential bidders with whom Enron had executed confidentiality agreements.

Enron has announced its intent to move forward with the sale of four companies, however, it continues to evaluate its alternatives with regard to Mariner. Management is unable to give assurances that the Company will be or not be sold in the near future and there can be no assurance as to whether JEDI's ownership of Mariner Energy LLC will be sold in the future.

(e) RISK FACTORS

EXPLORATION RISKS - In addition to the other information set forth elsewhere in this annual report, including the potential impact of the Enron bankruptcy matters, the following factors should be carefully considered when evaluating us. Exploration is a high-risk activity, and the 3-D seismic data and other advanced technologies we use cannot eliminate exploration risk. In addition, use of these technologies requires experienced technical personnel who we may be unable to attract or retain.

Our future success will depend on the success of our exploratory drilling program. Exploration activities involve numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be discovered. In addition, we are often uncertain as to the future cost or timing of drilling, completing and producing wells. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of the additional exploration time and expense associated with a variety of factors, including unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents, adverse weather conditions, compliance with governmental requirements and shortages or delays in the availability of drilling rigs or equipment.

Even when used and properly interpreted, 3-D seismic data and visualization techniques only assist geoscientists and geologists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know conclusively if hydrocarbons are present or economically producible. We could incur losses as a result of exploratory drilling expenditures. Poor results from exploration activities could affect future cash flows and results of operations materially and adversely.

Our exploratory drilling success will depend, in part, on our ability to attract and retain experienced explorationists and other professional personnel. Competition for explorationists and engineers with experience in the Gulf of Mexico is intense. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete in the Gulf of Mexico could be adversely affected.

Exploration for natural gas and oil at deeper drilling depths and in the deep waters of the Gulf of Mexico involves greater operational and financial risks than exploration at shallower depths and in shallower waters. These risks could result in substantial losses.

PROSPECT DEVELOPMENT RISKS - Our 2001 discoveries on South Timbalier ("Roaring Fork") and Viosca Knoll 917 ("Swordfish") have required and over the next year will continue to require significant financial resources. We do not expect production from these discoveries to commence prior to October 2003 and April 2004, respectively, but we must commit substantial resources in advance of the expected production date and cannot predict the price of oil if and when production commences.

OPERATING RISKS - The natural gas and oil business involves a variety of operating risks, including fires, explosions, blow-outs and surface cratering, uncontrollable flows of underground natural gas, oil and formation water, natural disasters, pipe or cement failures, casing collapses, embedded oilfield drilling and service tools, abnormally pressured formations and environmental hazards such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases. If any of these events occur, we could incur substantial losses as a result of injury or loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties, suspension of our operations and repairs to resume operations. If we experience any of these problems, well bores, platforms, gathering systems and processing facilities could be adversely affected, which in turn could adversely affect our ability to conduct operations.

Offshore operations are also subject to a variety of operating risks specific to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce or eliminate the funds available for exploration, development or leasehold acquisitions, or result in loss of equipment and properties.

Production of reserves from reservoirs in the Gulf of Mexico generally declines more rapidly than from reservoirs in many other producing regions of the world. This results in recovery of a relatively higher percentage of reserves from properties in the Gulf of Mexico during the initial few years of production. As a result, reserve replacement needs from new prospects are greater and require us to incur significant capital expenditures to replace production.

FINANCIAL POSITION RISKS - For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect our operations.

As part of our strategy, we explore for natural gas and oil at deeper drilling depths and in the deep waters of the Gulf of Mexico, where operations are more difficult and costly than at shallower depths. Deep depth and deep water drilling and operations require the application of recently developed technologies that involve a higher risk of mechanical failure. We have experienced and will continue to experience significantly higher drilling costs for our deepwater prospects. Furthermore, the deep waters of the Gulf of Mexico lack the physical and oilfield service infrastructure present in the shallower waters. As a result, a significant amount of time may elapse

between a deep water discovery and our marketing of the associated natural gas or oil, increasing both the financial and operational risk involved with these operations.

Our revenues, profitability and future growth depend substantially on prevailing prices for natural gas and oil. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital.

Conversely, our potential need to generate revenues to fund ongoing capital commitments or reduce indebtedness may limit our ability to slow or shut-in production from producing wells during periods of low prices for natural gas and oil.

Prices for natural gas and oil fluctuate widely. For example, natural gas prices declined significantly in 2002. Prices for natural gas and oil also declined significantly in 1998 and, for an extended period of time, remained substantially below prices obtained in previous years. Among the factors that can cause this fluctuation are the level of consumer product demand, weather conditions, domestic and foreign governmental regulations, the price and availability of alternative fuels, political conditions in natural gas and oil producing regions, the domestic and foreign supply of natural gas and oil, the price of foreign imports and overall economic conditions. If natural gas and oil prices decline, even if for only a short period of time, it is possible that write-downs of natural gas and oil properties could occur. While we attempt to partially minimize this risk through our hedging arrangements, hedging production has limited and may continue to limit potential gains from increases in commodity prices or result in losses.

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. These financial arrangements take the form of swap contracts or costless collars. The Company had in place both financial hedge and physical contracts with ENA at the time ENA filed for bankruptcy in December 2001. We did not receive payment as required under these contracts. We cannot provide assurance that other trading counterparties will not become credit risks in the future. Hedging arrangements expose us to risks in some circumstances, including situations when the other party to the hedging contract defaults on its contract obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. These hedging arrangements have limited and may continue to limit the benefit we could receive from increases in the prices for natural gas and oil. We cannot provide assurance that our hedging transactions will adequately protect us from fluctuations in natural gas and oil prices. We may choose not to engage in hedging transactions in the future. As a result, we may be adversely affected during periods of declining natural gas and oil prices.

We have experienced and expect to continue to experience substantial capital expenditure and working capital needs, particularly as a result of our drilling program. In the future, we expect we will require additional financing, in addition to cash generated from our operations, to fund our planned growth. We cannot be certain that additional financing will be available on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail our drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

We incurred net losses of $10.0 million, $58.4 million, and $20.2 million in 1999, 1998, and 1997, respectively. Our development of and participation in a larger number of prospects has required and will continue to require substantial capital expenditures. We cannot provide assurance that it will sustain profitability or positive cash flows from operating activities in the future. Our failure to sustain profitability in the future could adversely affect our company.

CONCENTRATION RISKS - We are subject to risks associated with the Gulf of Mexico, where substantially all of our exploration activities and production are located. This concentration of activity makes us more vulnerable than many of our competitors to the risks associated with the Gulf of Mexico, including delays and increased costs relating to adverse weather conditions, drilling rig and other oilfield services and compliance with environmental and other laws and regulations.

A significant part of the value of our production and reserves is concentrated in a small number of offshore properties. Because of this concentration, any production problems or inaccuracies in reserve estimates related to those properties are more likely to adversely impact our business. During 2002, over 62 percent of our production came from four properties in the Gulf of Mexico. If mechanical problems, storms or other events curtailed a substantial portion of this production, our cash flow would be adversely affected. In addition, at December 31, 2002 approximately 88 percent of the proved reserves was attributable to 7 properties. If the actual reserves associated with any one of these 7 properties are substantially less than the estimated reserves, our results of operations and financial condition could be adversely affected.

INDUSTRY RISKS - Our industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. One or more of the technologies that we currently use or that we may implement in the future may become obsolete, and we may be adversely affected. For example, marine seismic acquisition technology has been characterized by rapid technological advancements in recent years and further significant technological developments could substantially impair the 3-D seismic data's value.

We compete with major and independent natural gas and oil companies for property acquisitions. We also compete for the equipment and labor required to operate and develop properties. Most of our competitors have substantially greater financial and other resources than we do. As a result, in the deep water where exploration is more expensive, competitors may be better able to withstand sustained periods of unsuccessful drilling. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. These competitors may be able to pay more for exploratory prospects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, most of our competitors have been operating in the Gulf of Mexico for a much longer time than we have and have demonstrated the ability to operate through industry cycles.

Other companies operate some of the properties in which we have an interest. As a result, we have a limited ability to exercise influence over operations for these properties or their associated costs. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence operations and associated costs could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities. The success and timing of drilling and development activities on properties operated by others therefore depend upon a number of factors that are outside of our control, including timing and amount of capital expenditures, the operator's expertise and financial resources, approval of other participants in drilling wells and selection of technology.

RESERVE RISKS - The process of estimating natural gas and oil reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and net present value of reserves.

In order to prepare these estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions such as natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of natural gas and oil reserves are inherently imprecise.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of

exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control. At December 31, 2002, approximately 67 percent of our proved reserves were either proved undeveloped or proved non-producing. Moreover, some of the producing wells included in our reserve report had produced for a relatively short period of time as of December 31, 2002. Because most of the reserve estimates are not based on a lengthy production history and are calculated using volumetric analysis, these estimates are less reliable than estimates based on a lengthy production history.

It should not be assumed that the present value of future net cash flows from our proved reserves is the current market value of its estimated natural gas and oil reserves. In accordance with Securities and Exchange Commission requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the net present value estimate.

Our future natural gas and oil production depends on our success in finding or acquiring additional reserves. If we fail to replace reserves, our level of production and cash flows could be adversely impacted. In general, production from natural gas and oil properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both. Our ability to make the necessary capital investment to maintain or expand our asset base of natural gas and oil reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves. If we are not successful, our future production and revenues will be adversely affected.

REGULATION RISKS - We are subject to complex laws and regulations, including environmental regulations which can adversely affect the cost, manner or feasibility of doing business.

Exploration for and development, production and sale of natural gas and oil in the U.S. and especially in the Gulf of Mexico are subject to extensive federal, state and local laws and regulations, including environmental laws and regulations. We may be required to make large expenditures to comply with environmental and other governmental regulations. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations and taxation.

Under these laws and regulations, we could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. We do not believe that full insurance coverage for all potential environmental damages is available at a reasonable cost. Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that substantially increase costs. For example, Congress or the MMS could decide to limit exploratory drilling or natural gas production in additional areas of the Gulf of Mexico. Accordingly, any of these liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our financial condition and results of operations.

(f) CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our discussion and analysis of Mariner's financial condition and results of operation are based upon financial statements that have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in Note 1 to our financial statements. In response to SEC Release No. 33-8040, "Cautionary Advice Regarding Disclosure About Critical Accounting Policies," we have identified certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management. We analyze our estimates, including those related to oil and gas revenues, oil and gas properties, fair value of derivative instruments, income taxes and contingencies and litigation, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under

different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our financial statements:

OIL AND GAS PROPERTIES - Oil and gas properties are accounted for using the full-cost method of accounting. All direct costs and certain indirect costs associated with the acquisition, exploration and development of oil and gas properties are capitalized. Amortization of oil and gas properties is provided using the unit-of-production method based on estimated proved oil and gas reserves. No gains or losses are recognized upon the sale or disposition of oil and gas properties unless the sale or disposition represents a significant quantity of oil and gas reserves. The net carrying value of proved oil and gas properties is limited to an estimate of the future net revenues (discounted at 10%) from proved oil and gas reserves based on period-end prices and costs plus the lower of cost or estimated fair value of unproved properties.

The costs of unproved properties are excluded from amortization using the full-cost method of accounting. These costs are assessed quarterly for possible impairments or reduction in value based on geological and geophysical data. If a reduction in value has occurred, costs being amortized are increased.

The majority of the costs will be evaluated over the next three years.

CAPITALIZED INTEREST COSTS - The Company capitalizes interest based on the cost of major development projects which are excluded from current depreciation, depletion, and amortization calculations. Capitalized interest costs were approximately $1,022,000, $2,836,000, and $3,885,000 for the years ended December 31, 2002, 2001 and 2000, respectively.

ACCRUAL FOR FUTURE ABANDONMENT COSTS - Provision is made for abandonment costs calculated on a unit-of-production basis, representing the Company's estimated liability at current prices for costs which may be incurred in the removal and abandonment of production facilities at the end of the producing life of each property. On January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143 "Accounting for Asset Retirement Obligations" (See Recent Accounting Pronouncements).

HEDGING PROGRAM - The Company utilizes derivative instruments in the form of natural gas and crude oil price swap and price collar agreements in order to manage price risk associated with future crude oil and natural gas production and fixed-price crude oil and natural gas purchase and sale commitments. Such agreements are accounted for as hedges using the deferral method of accounting. Gains and losses resulting from these transactions, recorded at market value are deferred, and recorded in Accumulated Other Comprehensive Income ("AOCI") as appropriate, until recognized as operating income in the Company's Statement of Operations as the physical production hedged by the contracts is delivered.

The net cash flows related to any recognized gains or losses associated with these hedges are reported as oil and gas revenues and presented in cash flows from operations. If the hedge is terminated prior to expected maturity, gains or losses are deferred and included in income in the same period as the physical production hedged by the contracts is delivered.

The conditions to be met for a derivative instrument to qualify as a cash hedge are the following: (i) the item to be hedged exposes the Company to price risk; (ii) the derivative reduces the risk exposure and is designated as a hedge at the time the derivative contract is entered into; and (iii) at the inception of the hedge and throughout the hedge period there is a high correlation of changes in the market value of the derivative instrument and the fair value of the underlying item being hedged.

When the designated item associated with a derivative instrument matures, is sold, extinguished or terminated, derivative gains or losses are recognized as part of the gain or loss on sale or settlement of the underlying item. When a derivative instrument is associated with an anticipated transaction that is no longer expected to occur or if correlation no longer exists, the gain or loss on the derivative is recognized in income to the extent the future results have not been offset by the effects of price or interest rate changes on the hedged item since the inception of the hedge.

FINANCIAL INSTRUMENTS - The Company's financial instruments consist of cash and cash equivalents, receivables, payables, and debt. At December 31, 2002, 2001 and 2000, the estimated fair value of the Company's $100,000,000 Senior Subordinated Notes was approximately $99,000,000 and $95,000,000, respectively. The estimated fair value was determined based on borrowing rates available at December 31, 2001 and 2000, respectively, for debt with similar terms and maturities. The carrying amount of the Company's other instruments noted above approximate fair value.

MAJOR CUSTOMERS - During the year ended December 31, 2002, sales of oil and gas to three purchasers, including Enron affiliate, Bridgeline, accounted for 42%, 14% and 9% of total revenues. During the year ended December 31, 2001, sales of oil and gas to three purchasers, including an Enron affiliate, accounted for 32%, 24% and 14% of total revenues. During the year ended December 31, 2000, sales of oil and gas to two purchasers, including an affiliate, accounted for 49% and 16% of total revenues. Management believes that the loss of any of these purchasers would not have a material impact on the Company's financial condition or results of operations.

(g) RESULTS OF OPERATIONS

The following table repeats certain operating information found in Item 2 of this report with respect to oil and natural gas production, average sales price received and expenses per unit of production during the periods indicated.

	YEAR ENDING DECEMBER 31,		
	2002	2001	2000
PRODUCTION:			
Oil (MMbbls)...	1.7	3.0	1.
Natural gas (Bcf)......................................	29.6	18.8	25.
Gas equivalent (Bcfe)..................................	39.8	36.7	36.
AVERAGE REALIZED SALES PRICE (EXCLUDING THE EFFECTS OF HEDGING):			
Oil ($/Bbl)..	$21.60	$22.41	$29.5
Natural gas ($/Mcf)....................................	3.35	4.86	4.0
Gas equivalent ($/Mcfe)................................	3.41	4.31	4.3
AVERAGE REALIZED SALES PRICE (INCLUDING THE EFFECTS OF HEDGING):			
Oil ($/Bbl)..	$22.85	$23.22	$21.5
Natural gas ($/Mcf)....................................	4.03	4.57	3.2
Gas equivalent ($/Mcfe)................................	3.97	4.22	3.3
EXPENSES ($/MCFE):			
Lease operating..	$ 0.65	$ 0.55	$ 0.4
Transportation...	0.26	0.33	0.2
General and administrative, net........................	0.19	0.25	0.1
Depreciation, depletion and amortization (excluding impairments)..................	1.78	1.73	1.5

(i) 2002 COMPARED TO 2001

NET PRODUCTION increased during 2002 to 39.8 billion cubic feet of natural gas equivalent (Bcfe) from 36.7 Bcfe in 2001, an 8% improvement. Production from our King Kong and Yosemite projects more than offset production declines in our other fields, primarily the Pluto and Black Widow fields, located offshore.

HEDGING ACTIVITIES in 2002 increased our average realized natural gas price received by $0.68 per Mcf and revenues by $20.3 million, compared with a decrease of $0.29 per Mcf and revenues of $5.5 million in 2001. Our hedging activities with respect to crude oil during 2002 increased the average sales price received by $1.25 per Bbl and revenues by $2.1 million compared with an increase of $0.81 per Bbl and revenues of $2.4 million in 2001. Approximately $23.2 million of these hedge revenues were related to our ENA hedges and were not collected.

OIL AND GAS REVENUES increased 2% to $158.2 million for 2002 from $155.0 million for 2001, due to an 8% increase in Mcfe production offset by a 6% decrease in realized prices to $4.03 per Mcfe in 2002 from $4.22 per Mcfe in 2001.

LEASE OPERATING EXPENSES increased 30% to $26.1 million for 2002 from $20.1 million for 2001 due to the higher production costs associated with our King Kong and Yosemite projects.

TRANSPORTATION EXPENSES decreased 13% to $10.5 million for 2002 from $12.0 million for 2001. The decrease was attributable to lower production from our Pluto and Black Widow projects.

DEPRECIATION, DEPLETION, AND AMORTIZATION EXPENSE increased 11% to $70.8 million for 2002 from $63.5 million for 2001 as a result of the increase in the unit-of-production depreciation, depletion and amortization rate to $1.78 per Mcfe from $1.73 per Mcfe.

IMPAIRMENT OF ENRON RELATED RECEIVABLES of $3.2 million was recorded as a result of increasing our allowance from 90% to 100% of Enron receivables. In 2001 we recorded a $29.5 million allowance related to Enron receivables.

GENERAL AND ADMINISTRATIVE EXPENSES, which are net of overhead reimbursements received from other working interest owners, decreased 17% to $7.7 million for 2002 from $9.3 million for 2001 due lower personnel costs as a result of 2001 employee terminations.

NET INTEREST EXPENSE for 2002 increased 26% to $9.9 million from $8.2 million for 2001, primarily due to a reduction in capitalized interest.

INCOME (LOSS) BEFORE INCOME TAXES increased to a net income of $30.0 million for 2002 from $12.4 million in 2001, primarily a result of a $26.3 decrease in Enron related receivable allowance offset in part by increased expenses noted above.

(ii) 2001 COMPARED TO 2000

NET PRODUCTION increased during 2001 to 36.7 billion cubic feet of natural gas equivalent (Bcfe) from 36.3 Bcfe in 2000, a 1% improvement. Production from a full year of our Black Widow project more than offset production declines in our other fields, primarily the Sandy Lake field, located onshore, and the Dulcimer and Apia fields, located offshore.

HEDGING ACTIVITIES in 2001 (before de-designation due to the impact of the ENA bankruptcy) decreased our average realized natural gas price received by $0.29 per Mcf and revenues by $5.5 million, compared with a decrease of $0.83 per Mcf and revenues of $21.4 million in 2000. Our hedging activities with respect to crude oil during 2001 increased the average sales price received by $0.81 per Bbl and revenues by $2.4 million compared with a decrease of $7.99 per Bbl and revenues of $14.3 million.

OIL AND GAS REVENUES increased 28% to $155.0 million for 2001 from $121.1 million for 2000, due to a 26% increase in realized prices to $4.22 per Mcfe in 2001 from $3.34 per Mcfe in 2000.

LEASE OPERATING EXPENSES increased 17% to $20.1 million for 2001 from $17.2 million for 2000 due to the higher production costs associated with our Black Widow project.

TRANSPORTATION EXPENSES increased 54% to $12.0 million for 2001 from $7.8 million for 2000. The increase was attributable to a full year's transportation expenses on Black Widow as well as mandatory minimum transportation charges on our Pluto project.

DEPRECIATION, DEPLETION, AND AMORTIZATION EXPENSE increased 12% to $63.5 million for 2001 from $56.8 million for 2000 as a result of the increase in the unit-of-production depreciation, depletion and amortization rate to $1.73 per Mcfe from $1.57 per Mcfe.

IMPAIRMENT OF ENRON RELATED RECEIVABLES of $29.5 million was taken as a result of ENA filing a petition for bankruptcy protection (also see "Enron"). The allowance represents a 90% allowance on $7.0 million of settled physical and hedge contracts through December 31, 2001 and a 90% allowance on $25.3 million of hedge contracts marked to market value.

(h) LIQUIDITY AND CAPITAL RESOURCES

(i) CASH FLOWS AND LIQUIDITY

As of December 31, 2002, we had working capital deficit of approximately $9.2 million, of which $15.2 million was restricted, compared to a working capital deficit of $19.6 million at December 31, 2001. The improvement in the working capital was primarily a result of the sale, during 2002 of half of the Company's 50% working interest in its Falcon Project for approximately $52.3 million including reimbursements, with a portion of the proceeds being used to repay the Revolving Credit Facility. We expect our 2003 capital expenditures, excluding capitalized indirect costs and proceeds from property conveyances (see "Note 2. Oil & Gas Properties"), to be approximately $103.0 million, which approximates anticipated cash flow from operations. However, we believe that cash on hand together with expected cash flow and proceeds from our recent property conveyances (See Recent Events) will permit us to fund our planned activities in 2003. There can be no assurance that our access to capital will be sufficient to meet our needs for capital. Accordingly, we may be required to reduce our planned capital expenditures and forego planned exploratory drilling.

The Company's Revolving Credit Facility matured in October 2002, at which time there were no amounts outstanding. We are in discussions with other third party banks to provide a new revolving credit facility. There is no assurance that a new credit facility will be obtained. In addition, our parent, Mariner Energy LLC, is currently obligated under an unsecured term loan with an ENA affiliate. Mariner Energy LLC negotiated an extension of the ENA Affiliate Term Loan to March 20, 2004. In the event Mariner Energy LLC is unable to refinance or restructure its obligations prior to March 2004, Mariner Energy LLC would either default or be forced to sell its interest in the Company, or cause the Company to sell a substantial portion of its assets to repay its outstanding Senior Subordinated Notes so that it could distribute cash to Mariner Energy LLC to be used to repay the term loan. In the event of either a merger or consolidation of Mariner Energy LLC or the Company resulting in a change of control or a sale of all or substantially all of the Company's assets, holders of the Senior Subordinated Notes would have the right to require the Company to repurchase the Senior Subordinated Notes held by them at a purchase price in cash equal to 101% of the principal amount thereof plus accrued and unpaid interest. Any such transaction would also trigger a mandatory prepayment of all amounts outstanding under the ENA Affiliate Term Loan. The Company's ability to pay dividends and make other distributions of cash to Mariner Energy LLC are generally restricted under the indenture governing the Senior Subordinated Notes. As a result, following any change of control transaction or sale of all or substantially all of its assets, the Company would most likely be required to repurchase any Senior Subordinated Notes tendered to it under the indenture and redeem the balance of the Senior Subordinated Notes outstanding as permitted under the indenture before it could distribute cash to Mariner Energy LLC to repay the ENA Affiliate Term Loan.

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We had a net cash inflow of $6.5 million in 2002, compared to a net cash inflow of $9.5 million in 2001 and a net cash outflow of $2.3 million in 2000. A discussion of the major components of cash flows for these years follows.

	2002	2001	2000
Cash flows provided by operating activities (in millions)....	$60.2	$113.6	$63.9

Cash flows provided by operating activities in 2002 decreased by $53.4 million compared to 2001 due to lower oil and gas prices in 2002 and cash deposits for hedging activities. Cash flows from operating activities in 2001 increased by $49.6 million from 2000 primarily due to increased oil and gas prices, production lease operating and general and administrative expenses.

	2002	2001	2000
Cash flows used in investing activities (in millions)........	$53.8	$74.0	$79.1

Cash flows used in investing activities in 2002 decreased by $20.2 million compared to 2001 due to decreased proceeds from property conveyances. Cash flows used in investing activities in 2001 increased by $5.1 million compared to 2000 increased capital expenditures offset by $90.5 million in proceeds from property conveyances

	2002	2001	2000
Cash flows provided by financing activities (in millions)....	$ 0	$(30.0)	$17.4

Cash flows provided by financing activities in 2002 increased by $30.0 million compared to 2001. This increase was attributable to repayments of our Revolving Credit Facility in 2001 using proceeds from property conveyances mentioned above. Cash flows provided by financing activities in 2001 decreased by $47.4 million as compared to 2000 due to a $30 million net reduction in borrowings against our Revolving Credit Facility. In addition, capital contributions resulting from the sale of stock to Mariner Energy LLC increased by $31.7 million.

(ii) CHANGES IN PRICES AND HEDGING ACTIVITIES

The energy markets have historically been very volatile, and there can be no assurance that oil and gas prices will not be subject to wide fluctuations in the future. In an effort to reduce the effects of the volatility of the price of oil and natural gas on our operations, management has adopted a policy of hedging oil and natural gas prices from time to time primarily through the use of commodity swap and costless collar agreements. While the use of these hedging arrangements limits the downside risk of adverse price movements, it also limits future gains from favorable movements. Prior to 2002 all hedge activities historically have been conducted with Enron. As a result of the Enron bankruptcy we have de-designated all hedge positions (see "Enron"). In 2002 we implemented a new hedging program with a third party.

On June 28, 2002 the Company commenced price risk activities with a third party. These activities are intended to manage the Company's exposure to fluctuations in commodity prices for natural gas and crude. As of December 31, 2002 the Company had the following fixed price swaps outstanding.

TIME PERIOD	NOTIONAL QUANTITIES	FIXED PRICE	DECEMBER 31 FAIR VAL (million Gain/(Los
CRUDE OIL (MBbl)			
January 1 - December 31, 2003			
Fixed Price Swap	548	$24.02	$ (1.8)
Fixed Price Swap	183	$24.81	(0.4)
NATURAL GAS (MMbtu)			
January 1 - December 31, 2003			
Fixed Price Swap	730	$ 3.54	(7.5)
Fixed Price Swap	730	$ 3.60	(7.1)
			$(16.8)

The Company has reviewed the financial strength of its counterparts and believes credit risk to be minimal. As of December 31, 2002 the Company had on deposit, classified as restricted cash, $22.3 million with the third party for collateral. This collateral included $5.8 million in initial margin in cash and $16.5 million in mark-to-market exposure. Initial margin decreases as contracts settle.

As a result of increasing natural gas prices, in January and February of 2003, the Company unwound, through the purchase of counter positions, all natural gas swap contracts for the months of February through October 2003 locking in a loss of $23.2 million. This loss will be settled over the original contract period.

As a result of these swaps and other hedging transactions the Company will have approximately 31% of 2003 production subject to hedges. Mark to market value changes approximately $8.6 million for every 10% overall change in commodity prices.

The following table sets forth the results of hedging transactions during the periods indicated that were made with non-Enron related parties.

	DECEMBER 31, 2002	DECEMBER 31, 2001
NATURAL GAS		
Quantity hedged (Mmbtu)	--	--
Increase (Decrease) in Natural Gas Sales (in thousands)	--	--
CRUDE OIL		
Quantity hedged (MBbls)	169	--
Increase (Decrease) in Crude Oil Sales (in thousands)	$(325)	--

Our Senior Subordinated Notes bear interest at a fixed rate and, therefore, do not expose us to risk of earnings loss due to changes in market interest rates. The market value of the Senior Subordinated Notes was approximately $100 million based on borrowing rates available at December 31, 2002.

(iii) CAPITAL EXPENDITURES AND CAPITAL RESOURCES

CAPITAL EXPENDITURES AND CAPITAL RESOURCES

The following table presents major components of our capital and exploration expenditures for each of the three years in the period ended December 31, 2002.

	YEAR ENDING DECEMBER 31,		
	2002	2001	2000
CAPITAL EXPENDITURES (IN MILLIONS):			
LEASEHOLD ACQUISITION	$ 14.8	$ 8.8	$ 14.0
OIL AND NATURAL GAS EXPLORATION	25.5	57.5	17.2
OIL AND NATURAL GAS DEVELOPMENT AND OTHER	65.7	98.2	76.9
PROCEEDS FROM PROPERTY CONVEYANCES	(52.3)	(90.5)	(29.0)
TOTAL CAPITAL EXPENDITURES, NET OF PROCEEDS FROM PROPERTY CONVEYANCES	$ 53.7	$ 74.0	$ 79.1

Our capital expenditures for 2002 decreased $21.1 million as compared to 2001 as a result of lower proceeds from property conveyances and overall lower capital expenditures as result of our shift to a more balanced portfolio.

Our capital expenditures for 2001 were $74.0 million, including the $90.5 million of proceeds from property conveyances, which was $5.1 million less than 2000. The decrease was primarily a result of higher property conveyance proceeds offset in part by higher leasehold acquisition, geological and geophysical, and development expenditures.

Our estimated capital expenditure for 2003 is approximately $103 million before capitalized indirect costs and proceeds from property conveyances. Our budget includes approximately $41 million for exploration activities, $62 million for development activities and $121.6 million in proceeds from property conveyances. An active Gulf exploration program is underway, with funds budgeted to drill 8 to 12 wells. The development budget includes funds for completion of our Roaring Fork and Vermillion 144 projects and development costs for our Swordfish projects and other smaller fields.

Our long-term debt outstanding as of December 31, 2002 was approximately $99.8 million, comprised entirely of Senior Subordinated Notes.

Our Senior Subordinated Notes contain various restrictive covenants that, among other things, restrict the payment of dividends, limit the amount of debt we may incur, limit our ability to make certain loans, investments, enter into transactions with affiliates, sell assets, enter into mergers, limit our ability to enter into certain hedge transactions and provide that we must maintain specified relationships between cash flow and fixed charges and cash flow and interest on indebtedness.

We expect to fund our activities for 2003 through a combination of cash flow from operations and proceeds from property conveyances. Our capital resources may not be sufficient to meet our anticipated future requirements for working capital, capital expenditures and scheduled payments of principal and interest on our indebtedness.

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(i) CONTRACTUAL COMMITMENTS

We have numerous contractual commitments in the ordinary course of business, debt service requirements and operating lease commitments. The following table summarizes these commitments at December 31, 2002 (in millions):

	2003	2004	2005	2006
DEBT AND OTHER OBLIGATIONS.....................	$ --	$ --	$ --	$ 100
OPERATING LEASES..............................	0.7	0.6	0.6	0.5
TRANSPORTATION EXPENSES.......................	1.7	1.2	0.9	0.7
OTHER COMMITMENTS.............................	6.3	0.7	--	--
TOTAL CONTRACTUAL CASH COMMITMENTS..........	$ 8.7	$ 2.5	$ 1.5	$ 101.2

OTHER COMMITMENTS - In the ordinary course of business we enter into long-term commitments to purchase seismic data. The minimum annual payments under these contracts are $6.3 million in 2003 and $0.7 million in 2004.

MMS APPEAL - Mariner operates numerous properties in the Gulf of Mexico. Three of such properties were leased from the Mineral Management Service subject to the 1996 Royalty Relief Act. This Act relieved the obligation to pay royalties on certain predetermined leases until a designated volume is produced. These three leases contained language, which limited royalty relief if commodity prices exceeded predetermined levels. Beginning in January 2000 commodity prices exceeded the predetermined levels. Management believes the MMS did not have the authority to set pricing limits and the Company filed an administrative appeal with the MMS and has withheld royalties regarding this matter. The Company has recorded a liability for 100% of the exposure on this matter which on December 31, 2002 was $5.5 million.

(j) RECENT ACCOUNTING PRONOUNCEMENTS

Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations," addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 will be effective for us January 1, 2003 and early adoption is encouraged. SFAS No. 143 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. Currently, we include estimated future costs of abandonment and dismantlement in our full cost amortization base and amortize these costs as a component of our depletion expense. We adopted the provisions of SFAS 143 on January 1, 2003.

The adoption of SFAS 143 resulted in a January 1, 2003 cumulative effect adjustment to record (i) a $7.4 million increase in the carrying values of proved properties, (ii) a $2.1 million decrease in current abandonment liabilities. The net impact of items (i) through (ii) was to record a gain of $9.5 million as a cumulative effect adjustment of a change in accounting principle in our statements of operations upon adoption on January 1, 2003.

In April 2002 the Financial Accounting Standards Board ("FASB") issued SFAS No. 145, "Rescission of FASB Statements No. 4, No. 44, and No. 64, Amendment to FASB Statement No. 13 and Technical Corrections." SFAS No. 145 streamlines the reporting of debt extinguishments and requires that only gains and losses from extinguishments meeting the criteria in Accounting Policies Board Opinion 30 would be classified as extraordinary. Thus, gains or losses arising from extinguishments that are part of a company's recurring operations would not be reported as an extraordinary item. SFAS No. 145 is effective for fiscal years beginning after May 15, 2002 with earlier adoption encouraged. We do not expect the adoption of SFAS No. 145 to have a material impact on our financial position, results of operations or cash flows.

In June 2002 the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" and addresses accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force ("EITF") Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred. Under Issue 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. Under SFAS No. 146, fair value is the objective for initial measurement of the liability. SFAS No. 146 is effective for exit or disposal activities that are initiated after December 31, 2002, with early application encouraged. We do not expect the adoption of SFAS No. 146 to have a material impact on our financial position, results of operations or cash flows.

In December 2002 the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure" and the transition guidance and annual disclosure provisions are effective for us for the year ended December 31, 2002. SFAS No. 148 amends SFAS Statement No. 123, "Accounting for Stock Based Compensation" and provides alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, the statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based compensation and the effect of the method used. We adopted SFAS No. 148 for 2002.

In November 2002, the FASB issued Interpretation No. 45 (FIN 45), "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," which addresses the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees. FIN 45 also requires the recognition of a liability by a guarantor at the inception of certain guarantees that are entered into or modified after December 31, 2002.

The company has adopted the disclosure requirements of FIN 45 and will apply the recognition and measurement provisions for all material guarantees entered into or modified in periods beginning January 1, 2003. The impact of FIN 45 on the company's future Financial Statements will depend upon whether the company enters into or modifies any material guarantee arrangements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - (d) (ii) Changes in Prices and Hedging Activities.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS

INDEPENDENT AUDITORS' REPORT

Board of Directors and Stockholder
Mariner Energy, Inc.
Houston, Texas

We have audited the accompanying balance sheets of Mariner Energy, Inc. (the "Company") as of December 31, 2002 and 2001 and the related statements of operations, stockholder's equity and cash flows for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these 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 financial statements referred to above present fairly, in all material respects, the financial position of Mariner Energy, Inc. as of December 31, 2002 and 2001, and the results of its operations and cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles general accepted in the United States of America.

As described in Note 2, the Company has various related-party transactions and certain control relationships with Enron Corp.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
April 14, 2003

MARINER ENERGY, INC.
BALANCE SHEETS
(IN THOUSANDS, EXCEPT SHARE DATA)

	YEAR ENDED DECEMBER 31, 2002	2001
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents..............................	$ 18,344	$ 11,83

Restricted cash	15,195	-
Receivables	29,673	34,12
Prepaid expenses and other	6,757	10,00
Total current assets	69,969	55,96
PROPERTY AND EQUIPMENT:		
Oil and gas properties, at full cost:		
Proved	620,949	583,20
Unproved, not subject to amortization	44,630	29,34
Total	665,579	612,54
Other property and equipment	5,601	5,75
Accumulated depreciation, depletion and amortization	(383,601)	(316,56
Total property and equipment, net	287,579	301,73
OTHER ASSETS, NET OF AMORTIZATION	2,636	2,98
LONG-TERM RELATED PARTY RECEIVABLE	--	3,22
TOTAL ASSETS	$ 360,184	$ 363,90
LIABILITIES AND STOCKHOLDER'S EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 38,438	$ 43,57
Accrued liabilities	36,313	27,54
Accrued interest	4,375	4,46
Total current liabilities	79,126	75,59
OTHER LIABILITIES	11,141	8,45
LONG-TERM DEBT:		
Senior Subordinated Notes	99,821	99,77
STOCKHOLDER'S EQUITY:		
Common stock, $1 par value; 2,000 and 1,000 shares authorized, 1,380 issued and outstanding, at December 31 2002 and December 31, 2001	1	
Additional paid-in-capital	227,318	227,31
Accumulated other comprehensive income(loss)	(14,177)	25,80
Accumulated deficit	(43,046)	(73,03
Total stockholder's equity	170,096	180,08
TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY	$ 360,184	$ 363,90

The accompanying notes are an integral part of these financial statements

MARINER ENERGY, INC.
STATEMENTS OF OPERATIONS
(IN THOUSANDS)

	YEAR ENDING DECEMBER 31	
	2002	2001
REVENUES:		
Oil sales	$ 38,792	$ 69,145
Gas sales	119,436	85,855
Total revenues	158,228	155,000
COSTS AND EXPENSES:		
Lease operating expense	26,076	20,063
Transportation expense	10,480	12,011
General and administrative expense	7,716	9,274
Depreciation, depletion and amortization	70,821	63,503
Impairment of Enron related receivables	3,234	29,529
Total costs and expenses	118,327	134,380
OPERATING INCOME	39,901	20,620
INTEREST:		
Income	390	663
Expense	(10,298)	(8,890)
INCOME BEFORE TAXES	29,993	12,393
PROVISION FOR INCOME TAXES	--	--
NET INCOME	29,993	$ 12,393

The accompanying notes are an integral part of these financial statements

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MARINER ENERGY, INC.
STATEMENTS OF STOCKHOLDER'S EQUITY
(IN THOUSANDS, EXCEPT NUMBER OF SHARES)

	ADDITIONAL	ACCUMULATED OTHER

	COMMON STOCK SHARES	COMMON STOCK AMOUNT	PAID-IN CAPITAL	COMPREHENSIVE INCOME	ACC D
BALANCE AT DECEMBER 31, 2000	1,380	$ 1	$227,318	$ --	$(
Net income..................					
Cumulative effect of change in accounting principle...	--	-	--	(32,976)	
Change in fair value of derivative hedging instruments..............	--	-	--	61,909	
Hedge settlements reclassified to income....	--	-	--	(3,130)	
Total comprehensive income...	--	-	--	--	
BALANCE AT DECEMBER 31, 2001	1,380	$ 1	$227,318	$ 25,803	$(
Net income..................					
Change in fair value of derivative hedging instruments..............	--	-	--	(17,105)	
Hedge settlements reclassified to income....	--	-	--	(22,875)	
Total comprehensive income...	--	-	--	--	
BALANCE AT DECEMBER 31, 2002	1,380	$ 1	$227,318	$ (14,177)	$(

The accompanying notes are an integral part of these financial statements

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MARINER ENERGY, INC.
STATEMENTS OF CASH FLOWS
(IN THOUSANDS)

	YE DE
	2002
OPERATING ACTIVITIES:	

Net income	$ 29,993
Adjustments to reconcile net loss to net cash provided by operating activities:	
Depreciation, depletion and amortization......................	70,588
Hedge Gain	(23,200)
Impairment of Enron related receivables.......................	3,223
Loss on sale of fixed assets	69
Changes in operating assets and liabilities:	
Receivables...	4,449
Prepaid expenses and other....................................	3,249
Other assets..	344
Restricted Cash...	(15,195)
Accounts payable and accrued liabilities......................	(13,245)
Net cash provided by operating activities.....................	60,275
INVESTING ACTIVITIES:	
Additions to oil and gas properties...............................	(105,360)
Proceeds from property conveyances................................	52,329
Additions to other property and equipment.........................	(738)
Net cash used in investing activities	(53,769)
FINANCING ACTIVITIES:	
Repayment of revolving credit facility............................	--
Capital contributed by sale of stock to parent....................	--
Proceeds from (payments to) the affiliate credit facility.........	--
Net cash (used in) provided by financing activities...........	--
INCREASE IN CASH AND CASH EQUIVALENTS.....................................	6,506
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD..........................	11,838
CASH AND CASH EQUIVALENTS AT END OF PERIOD................................	$ 18,344

The accompanying notes are an integral part of these financial statements

MARINER ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS -- (CONTINUED)

MARINER ENERGY, INC.
NOTES TO FINANCIAL STATEMENTS
FOR THE YEARS ENDED DECEMBER 31, 2002, 2001 AND 2000

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION - Through March 31, 1996, Hardy Oil & Gas USA Inc. (the "Predecessor Company") was a wholly owned subsidiary of Hardy Holdings Inc., which is a wholly owned subsidiary of Hardy Oil & Gas Plc ("Hardy Plc"), a company incorporated in the United Kingdom. Pursuant to a stock purchase agreement dated April 1, 1996, Joint Energy Development Investments Limited Partnership ("JEDI"), Enron North America Corp. ("ENA") (see "Note 2. Related-Party Transactions"), together with members of management of the

Predecessor Company, formed Mariner Holdings, Inc. ("Mariner Holdings"), which then purchased from Hardy Holdings Inc. all of the issued and outstanding stock of the Predecessor Company for a purchase price of approximately $185.5 million effective April 1, 1996 for financial accounting purposes (the "Acquisition"). After the acquisition, the name of the predecessor company was changed to Mariner Energy, Inc. (the "Company"). The Company is primarily engaged in the exploration and exploitation for and development and production of oil and gas reserves, with principal operations both onshore and offshore Texas and Louisiana.

EXCHANGE OFFERING - In October 1998, JEDI and other shareholders exchanged all of their common shares of Mariner Holdings, the Company's parent, for an equivalent ownership percentage in common shares of Mariner Energy LLC. As of December 31, 1999 Mariner Energy LLC owned 100% of Mariner Holdings.

CASH AND CASH EQUIVALENTS - All short-term, highly liquid investments that have an original maturity date of three months or less are considered cash equivalents.

RECEIVABLES - Substantially all of the Company's receivables arise from sales of oil or natural gas, or from reimbursable expenses billed to the other participants in oil and gas wells for which the Company serves as operator.

OIL AND GAS PROPERTIES - Oil and gas properties are accounted for using the full-cost method of accounting. All direct costs and certain indirect costs associated with the acquisition, exploration and development of oil and gas properties are capitalized. Amortization of oil and gas properties is provided using the unit-of-production method based on estimated proved oil and gas reserves. No gains or losses are recognized upon the sale or disposition of oil and gas properties unless the sale or disposition represents a significant quantity of oil and gas reserves, which would have a significant impact on the depreciation, depletion and amortization. The net carrying value of proved oil and gas properties is limited to an estimate of the future net revenues (discounted at 10%) from proved oil and gas reserves based on period-end prices and costs plus the lower of cost or estimated fair value of unproved properties.

The costs of unproved properties are excluded from amortization using the full-cost method of accounting. These costs are assessed quarterly for possible impairments or reduction in value based on geological and geophysical data. If a reduction in value has occurred, costs being amortized are increased. The majority of the costs will be evaluated over the next three years.

OTHER PROPERTY AND EQUIPMENT - Depreciation of other property and equipment is provided on a straight-line basis over their estimated useful lives, which range from three to seven years.

OTHER ASSETS - Other assets are primarily deferred loans stated at cost subject to amortization over the life of the related debt. Accumulated amortization as of December 31, 2002 and 2001 was $5.3 million and $4.9 million, respectively.

INCOME TAXES - The Company's taxable income is included in a consolidated United States income tax return with Mariner Energy LLC. The intercompany tax allocation policy provides that each member of the consolidated group compute a provision for income taxes on a separate return basis. The Company records its income taxes using an asset and liability approach which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax bases of assets and liabilities. Valuation allowances are established when necessary to reduce deferred tax assets to the amount more likely than not to be recovered.

CAPITALIZED INTEREST COSTS - The Company capitalizes interest based on the cost of major development projects which are excluded from current depreciation, depletion, and amortization calculations. Capitalized interest costs were approximately $1,022,000, $2,836,000, and $3,885,000 for the years ended December 31, 2002, 2001 and 2000, respectively.

ACCRUAL FOR FUTURE ABANDONMENT COSTS - Provision is made for abandonment costs calculated on a unit-of-production basis, representing the Company's estimated liability at current prices for costs which may be incurred in the removal and abandonment of production facilities at the end of the producing life of each property. On January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143 "Accounting for Asset Retirement Obligations" (See Recent Accounting Pronouncements).

HEDGING PROGRAM - The Company utilizes derivative instruments in the form of natural gas and crude oil price swap and price collar agreements in order to manage price risk associated with future crude oil and natural gas production and fixed-price crude oil and natural gas purchase and sale commitments. Such agreements are accounted for as hedges using the deferral method of accounting. Gains and losses resulting from these transactions, recorded at market value are deferred, and recorded in Accumulated Other Comprehensive Income ("AOCI") as appropriate, until recognized as operating income in the Company's Statement of Operations as the physical production hedged by the contracts is delivered.

The net cash flows related to any recognized gains or losses associated with these hedges are reported as oil and gas revenues and presented in cash flows from operations. If the hedge is terminated prior to expected maturity, gains or losses are deferred and included in income in the same period as the physical production hedged by the contracts is delivered.

The conditions to be met for a derivative instrument to qualify as a cash flow hedge are the following: (i) the item to be hedged exposes the Company to price risk; (ii) the derivative reduces the risk exposure and is designated as a hedge at the time the derivative contract is entered into; and (iii) at the inception of the hedge and throughout the hedge period there is a high correlation of changes in the market value of the derivative instrument and the fair value of the underlying item being hedged.

When the designated item associated with a derivative instrument matures, is sold, extinguished or terminated, derivative gains or losses are recognized as part of the gain or loss on sale or settlement of the underlying item. When a derivative instrument is associated with an anticipated transaction that is no longer expected to occur or if correlation no longer exists, the gain or loss on the derivative is recognized in income to the extent the future results have not been offset by the effects of price or interest rate changes on the hedged item since the inception of the hedge.

REVENUE RECOGNITION - The Company recognizes oil and gas revenue from its interests in producing wells as oil and gas from those wells is produced and sold. Oil and gas sold is not significantly different from the Company's share of production.

FINANCIAL INSTRUMENTS - The Company's financial instruments consist of cash and cash equivalents, receivables, payables, and debt. At December 31, 2002 and 2001, the estimated fair value of the Company's $100,000,000 Senior Subordinated Notes was approximately $99,000,000 and $95,000,000, respectively. The estimated fair value was determined based on borrowing rates available at December 31, 2002 and 2001, respectively, for debt with similar terms and maturities. The carrying amount of the Company's other instruments noted above approximate fair value.

USE OF ESTIMATES IN THE PREPARATION OF FINANCIAL STATEMENTS - The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from these estimates.

MAJOR CUSTOMERS - During the year ended December 31, 2002, sales of oil and gas to three purchasers, including an Enron affiliate, accounted for 42%, 14% and 9% of total revenues. During the year ended December 31, 2001, sales of oil and gas to three purchasers, including an Enron affiliate, accounted for 31%, 24% and 14% of total revenues. During the year ended December 31, 2000, sales of oil and gas to two purchasers, including an affiliate, accounted for 49% and 16% of total revenues. Management believes that the loss of any of these purchasers would not have a material impact on the Company's financial condition or results of operations.

RECLASSIFICATIONS - Certain reclassifications were made to the prior year's financial statements to conform to the current year presentation.

STOCK OPTIONS - Historically, we have accounted for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Accordingly, compensation cost for stock options is measured as the excess, if any, of the fair value of common stock at the date of the grant over the amount the employee must pay to acquire the common stock. If the exercise price of a stock option is equal to the fair market value at the time of grant, no compensation expense is incurred.

RECENT ACCOUNTING PRONOUNCEMENTS - Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations," addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 will be effective for us January 1, 2003 and early adoption is encouraged. SFAS No. 143 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. Currently, we include estimated future costs of abandonment and dismantlement in our full cost amortization base and amortize these costs as a component of our depletion expense. We adopted the provisions of SFAS 143 on January 1, 2003.

The adoption of SFAS 143 resulted in a January 1, 2003 cumulative effect adjustment to record (i) a $2.1 million increase in the carrying values of proved properties, (ii) a $7.4 million increase in current abandonment liabilities. The net impact of items (i) through (ii) was to record a gain of $9.5 million as a cumulative effect adjustment of a change in accounting principle in our statements of operations upon adoption on January 1, 2003.

In April 2002 the Financial Accounting Standards Board ("FASB") issued SFAS No. 145, "Rescission of FASB Statements No. 4, No. 44, and No. 64, Amendment to FASB Statement No. 13 and Technical Corrections." SFAS No. 145 streamlines the reporting of debt extinguishments and requires that only gains and losses from extinguishments meeting the criteria in Accounting Policies Board Opinion 30 would be classified as extraordinary. Thus, gains or losses arising from extinguishments that are part of a company's recurring operations would not be reported as an extraordinary item. SFAS No. 145 is effective for fiscal years beginning after May 15, 2002 with earlier adoption encouraged. We do not expect the adoption of SFAS No. 145 to have a material impact on our financial position, results of operations or cash flows.

In June 2002 the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" and addresses accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force ("EITF") Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred. Under Issue 94-3, a liability for an exit cost was recognized at the date of an entity's commitment to an exit plan. Under SFAS No. 146, fair value is the objective for initial measurement of the liability. SFAS No. 146 is effective for exit or disposal activities that are initiated after December 31, 2002, with early application encouraged. We do not expect the adoption of SFAS No. 146 to have a material impact on our financial position, results of operations or cash flows.

In December 2002 the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure" and the transition guidance and annual disclosure provisions are effective for us for the year ended December 31, 2002. SFAS No. 148 amends SFAS Statement No. 123, "Accounting for Stock Based Compensation" and provides alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, the statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based compensation and the effect of the method used. We adopted SFAS No. 148 for 2002.

In November 2002, the FASB issued Interpretation No. 45 (FIN 45), "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," which addresses the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees. FIN 45 also requires the recognition of a liability by a guarantor at the inception of certain guarantees that are entered into or modified after December 31, 2002.

The company has adopted the disclosure requirements of FIN 45 (see Note 2 "Related-Party Transactions) and will apply the recognition and measurement provisions for all material guarantees entered into or modified in periods beginning January 1, 2003. The impact of FIN 45 on the company's future Financial Statements will depend upon whether the company enters into or modifies any material guarantee arrangements.

2. RELATED-PARTY TRANSACTIONS

ENRON BANKRUPTCY - Commencing on December 2, 2001, Enron Corp. ("Enron") and certain of its affiliates, including Enron North America Corp. ("ENA"), filed voluntary petitions for bankruptcy protection. We have been informed that of our various direct or indirect owners, only Enron and ENA are debtors in the bankruptcy. We do not know at this time if any other owners will seek bankruptcy protection or what effect, if any, this may have on the ownership of Mariner Energy LLC which owns 100% of Mariner Holdings, Inc. (our direct parent) or on Joint Energy Development Investments Limited Partnership ("JEDI"), which owns approximately 96% of the issued and outstanding equity of Mariner Energy LLC. Enron is the parent of ENA, and an affiliate of ENA is the general partner of JEDI. JEDI is 100% owned by Enron and affiliates of ENA. Accordingly, Enron may be deemed to control JEDI, Mariner Energy LLC, Mariner Holdings and us. Additionally, five of the Company's directors are officers of Enron or affiliates of Enron. Because of these various potentially conflicting interests, ENA, the Company, JEDI and the minority shareholders of Mariner Energy LLC have entered into an agreement that is intended to make clear that Enron and its affiliates have no duty to make business opportunities available to the Company.

Mariner Energy LLC's only asset is 100% of the common stock of Mariner Holdings, Inc., our direct parent. The only asset of Mariner Holdings is 100% of the common shares of Mariner.

Management cannot predict with certainty what impact Enron's bankruptcy may have on us. However, it does believe that our assets and liabilities will not become part of the Enron estate in bankruptcy. Although JEDI owns 96% of Mariner Energy LLC's common shares, we, as a separate corporation own or lease the assets used in its business and our management, separate from Enron, is responsible for our day-to-day operations. Contractual provisions restrict Enron access to our assets. We maintain our own accounting system as well as separate debt ratings. We maintain our own separate and complete cash management system and finance its operations separately from Enron, on both a short-term and long-term basis. We file a consolidated tax return with Mariner Energy LLC.

Notwithstanding the above, we may have potential exposure to certain liabilities and asset impairments as a result of Enron's bankruptcy. Portions following Enron-related disclosures are based on discussions with Enron's legal advisors and management, including members of our Board of Directors. Although our management has implemented with Enron's legal advisor and management a systematic method of identifying Enron matters which may have a material impact on us, management cannot provide any assurance as the completeness or accuracy of the information provided by or on behalf of Enron.

ORGANIZATION AND OWNERSHIP OF THE COMPANY - Through March 31, 1996, Hardy Oil & Gas USA Inc. (the "Predecessor Company") was a wholly-owned subsidiary of Hardy Holdings Inc., which is a wholly-owned subsidiary of Hardy Oil & Gas Plc ("Hardy Plc"), a company incorporated in the United Kingdom. Pursuant to a stock purchase agreement dated April 1, 1996, JEDI and ENA, together with members of management of the Predecessor Company, formed Mariner Holdings, Inc. ("Mariner Holdings"). Mariner Holdings then purchased from Hardy Holdings Inc. all of the issued and outstanding stock of the Predecessor Company for a purchase price of approximately $185.5 million (the "Acquisition"). After the Acquisition, the name of the Predecessor Company was changed to Mariner Energy, Inc. In October 1998, JEDI and other shareholders exchanged all of their common shares of Mariner Holdings, the Company's direct parent, for an equivalent ownership percentage in common shares of Mariner Energy LLC. Mariner Energy LLC owns 100% of Mariner Holdings.

Subsequent to the Acquisition, Mariner Energy LLC, Mariner Holdings and Mariner have each entered into various financing and operating transactions with affiliates. In addition, the Company may have from time to time engaged in various commercial transactions and have various commercial relationships with Enron and certain affiliates of Enron, such as holding and exploring, exploiting and developing joint working interests in particular prospects and properties and entering into other oil and gas related or financial transactions. Certain of the Company's third-party debt instruments and arrangements restrict the Company's ability to engage in transactions with its affiliates, but those restrictions are subject to significant exceptions. The Company believes that its current agreements with Enron and its affiliates are, and anticipates that any future agreements with Enron and its affiliates will be, on terms no less favorable to the Company than would be obtained in an agreement with a third party. Below is a summary of key transactions between the Company and affiliate entities.

MARINER ENERGY LLC

ENA Affiliate Term Loan - In March 2000, Mariner Energy LLC established an unsecured term loan with ENA to repay amounts outstanding under various affiliate credit facilities at Mariner Energy LLC and Mariner and to provide additional working capital. The additional working capital of $55 million was contributed to Mariner in 2000. The loan bears interest at 15%, which interest accrues and is added to the loan principal. Repayment of the balance of loan principal and accrued interest, which was approximately $164.4 million as of December 31, 2002, is due March 20, 2004. In conjunction with the loan agreement, two five-year warrants were issued to ENA providing the right to purchase up to 900,000 of common shares of Mariner Energy LLC for $0.01 per share.

Covenants in Mariner's Senior Subordinated Notes restrict the funds of Mariner that can be distributed to Mariner Energy LLC. Accordingly, Mariner Energy LLC is restricted in its ability to repay the unsecured Term Loan or to distribute earnings to its shareholders. In the event Mariner Energy LLC is unable to restructure or extend the maturity of its obligations prior to March 2004 it would either default under the Term Loan or be forced to sell its interest in Mariner or cause Mariner to sell a substantial portion of its assets to repay any outstanding Senior Subordinated Notes so that it could distribute any remaining cash proceeds to Mariner Energy LLC to be used to repay the Term Loan.

We have been informed by Enron's legal advisors and management that the Term Loan and warrants were transferred from ENA to an ENA affiliate, which affiliate is part of a finance structure formed by ENA. Because debt obligations of the finance structure are in default and ENA therefore does not have complete control over decisions made by the ENA affiliate, it may be difficult for Mariner Energy LLC to obtain any consents, waivers or amendments needed from the ENA affiliate in connection with the Term Loan or the warrants.

MARINER HOLDINGS, INC.

1998 Equity Investment - In June 1998, Mariner Holdings issued additional equity to its existing shareholders, including JEDI, for approximately $14.58 per share, for a net investment of $28.8 million, all of which was contributed to Mariner. Mariner Holdings paid approximately $1.2 million as a structuring fee, on a pro rata basis, to existing shareholders participating in this transaction. Approximately $1 million of this fee was paid to ECT Securities Limited Partnership.

MARINER ENERGY, INC.

Oil and Gas Production Sales to ENA or Affiliates - During the three years ending December 31, 2002, 2001 and 2000, sales of oil and gas production to ENA or affiliates were $56.4million, $50.2 million and $73.4 million, respectively. These sales were generally made on 1 to 3 month contracts. At the time ENA filed its petition for bankruptcy protection, the Company immediately ceased selling its physical production to ENA, however, we continued to sell our production to Bridgeline which ENA owned a minority interest. All amounts sold to this party have been collected. As of December 31, 2002, we had an outstanding receivable for $3 million from ENA. This amount was not paid as scheduled and is still outstanding. Mariner has submitted a proof of claim to the bankruptcy court for amounts owed to it by ENA. The Company has estimated 100% of this balance is uncollectible and has recorded a full allowance and related expense.

Management Activities - We engage in price risk management activities from time to time. These activities are intended to manage our exposure to fluctuations in commodity prices for natural gas and crude oil. We primarily utilize price swaps and costless collars as a means to manage such risk. Historically, all of our hedging contracts were with ENA. As a result of ENA's bankruptcy, the contracts are currently in default. The November 2001 through April 30, 2002 settlements for oil and gas have not been collected. In addition, on May 14, 2002, we elected under its Master Service Agreement with ENA to terminate all open contracts. The effect of this termination is to fix the nominal value on all remaining contracts on May 14, 2002. Subsequent to this termination, the value of all oil and natural gas unpaid hedge contracts was $7.7 million. We have estimated 100% of this balance is uncollectible and have recorded a full allowance. We have submitted a proof of claims to the bankruptcy court for amounts owed under this agreement. In accordance with Statement of Financial Accounting Standards ("SFAS") No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 137 and No. 138, we have de-designated our contracts effective December 2, 2001 and are recognizing all market value changes subsequent to such de-designation in our earnings. The value recorded up to the time of de-designation and included in Accumulated Other Comprehensive Income ("AOCI"), will reverse out of AOCI and into earnings as the original corresponding production, as hedged by the contracts, is produced. For the year ending December 31, 2002 approximately $23.2 million has reversed out to earnings. As of December 31, 2002, $2.6 million remained in AOCI to be reversed out to earnings.

The following table sets forth the results of hedging transactions during the periods indicated that were made with ENA (all amounts shown are non-cash items):

	YEAR ENDING DE	
	2002	2001
Natural gas quantity hedged (Mmbtu).........................	18,090	17,73
Increase (decrease) in natural gas sales (thousands).........	$ 20,413	$ (5,52
Crude oil quantity hedged (MBbls)...........................	446	75
Increase (decrease) in crude oil sales (thousands)...........	$ 2,787	$ 2,39

MARINER ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS -- (CONTINUED)

Supplemental Affiliate Data - provided below is a supplemental balance sheet and income statement for affiliate entities:

BALANCE SHEET DATA	DECEMBER 31, 2002 AMOUNTS (IN MILLIONS)	TOTAL	D
RELATED PARTY RECEIVABLE:			
Derivative Asset	$ --		$ 2.5
Settled Hedge Receivable	--		0.4
Oil and Gas Receivable	8.2	8.2	0.3
ACCRUED LIABILITIES:			
Transportation Contract	--	--	0.9
Service Agreement	0.6	1.5	0.3
STOCKHOLDER'S EQUITY:			
Common Stock	$ .001	--	$ .001
Additional Paid in Capital	$227.3		$227.3
Accumulated other Comprehensive Income	$ 2.3	$ 229.6	$ 25.8

INCOME STATEMENT DATA	YEAR ENDED DECEMBER 3 2002
Oil and Gas Sales	$ 56.4
General and Administrative Expenses	0.4
Transportation Expenses	2.7
Unrealized loss and other non-cash derivative instrument adjustments	3.2

As a result of the Enron and ENA bankruptcies, among other implications, we may not be able to obtain credit from banks or trade vendors or enter into hedging arrangements on acceptable terms. To date, our operations have not been materially affected by the bankruptcies; however, our ability to enter into certain transactions including purchase or sale arrangements and to conduct significant capital programs may be affected in the future. Oil and gas sales and the related accounts receivable for the year ending December 31, 2002 relate to sales made to a minority owed affiliate of Enron.

CONTROLLED GROUP LIABILITY

On November 12, 2002, Enron's legal advisors and management informed us that we may be an Enron Corp. Controlled Group Member as defined under the Employee Retirement Income Security Act of 1974 ("ERISA") due to Enron's indirect ownership interest in Mariner Energy LLC. Enron management has not made a final determination if we are in fact a Controlled Group Member. Because of numerous ownership issues within the Enron Group, we are unable to make our own determination as to whether we agree or disagree that we are a Controlled Group Member. In the event we are a Controlled Group Member, we may have potential liability for certain employee benefit plan obligations of Enron discussed below.

Pension Plans - Applicable federal law authorizes the Pension Benefit Guaranty Corporation ("PBGC") to institute proceedings in federal district court for the termination of a pension plan if it determines the plan has failed to comply with minimum funding standards, the plan is or will be unable to pay benefits when due, or the failure to terminate the plan may reasonably be expected to unreasonably increase the possible long-run loss to the PBGC. Federal law also authorizes the sponsor of a pension plan to terminate the plan at a time when the plan is underfunded, subject to PBGC or court approval.

Based on discussions with Enron management, it is our management's understanding that, as of December 31, 2002 the assets of Enron's pension plan (the "Enron Plan") were less than the present value of all accrued benefits by approximately $52 million on a SFAS No. 87 basis and approximately $182 million on a plan termination basis. Further, Enron's management has informed Mariner management that the PBGC has filed claims in the Enron bankruptcy cases. The claims are duplicative in nature, representing unliquidated claims for PBGC insurance premiums (the "Premium Claims") and unliquidated claims for due but unpaid minimum funding contributions (the "Contribution Claims") under the

Internal Revenue Code of 1986, as amended (the "Tax Code") 29 U.S.C. Sections 412(a) and 1082 and claims for unfunded benefit liabilities (the "UBL" Claims"). Enron and the relevant sponsors of the defined benefit plans are current on their PBGC premiums and their contributions to the pension plans. Therefore, Enron has valued the Premium Claims and the Contribution Claims at $0. The total amount of the UBL Claims is $305.5 million (including $271 million for the Enron Plan). In addition Enron Management has informed Mariner Management that the PBGC has informally alleged in pleadings filed with the bankruptcy court that the UBL Claim related to the Enron Plan could increase by as much as 100%. PBGC has provided no support (statutory or otherwise) for this assertion and Enron Management disputes the validity of any such claim. Because the Enron Plan is under funded and Enron is in bankruptcy, in certain circumstances the Enron Plan may be terminated and taken control of by the PBGC upon approval of a Federal District Court.

Mariner's employees have not been participants in the Enron Plan. However, upon termination of a pension plan, all of the members of the controlled group of the plan sponsor become jointly and severally liable for the plan are under funding. The PBGC can demand payment from one or more of the members of the controlled group. If payment is not made, a lien in favor of the PBGC automatically arises against all of the assets of that member of the Controlled Group. The amount of the lien is equal to the lesser of the underfunding or 30% of the aggregate net worth of all of the controlled group members. In addition, if the sponsor of a pension plan does not timely satisfy its minimum funding obligation to the pension plan, once the aggregate missed amounts exceed $1 million, a lien in favor of the plan in the amount of the missed funding automatically arises against the assets of every member of the controlled group. In either case, the PBGC may file to perfect the lien and attempt to enforce it against the assets of members of the Enron Controlled Group. Mariner has been informed by Enron that Enron's management believes that the lien would be subordinate to prior perfected liens on the assets of the member of the controlled group. Based on discussions with Enron's management, Mariner's management understands that Enron has made all required contributions to date through October 15, 2002. Enron's management has advised us that it intends to make its next contribution, due in the first quarter of 2003.

Management cannot predict the outcome of the above matters or estimate any potential loss. In addition, if the PBGC did look solely to Mariner to pay any amount with respect to the Enron Plan, Mariner would exercise all legal rights, available to it to defend against such a demand and to recover any contributions from the other solvent members of the Controlled Group. No reserves have been established by Mariner for any amounts related to this issue.

Mariner has also been informed by Enron management that Enron has contacted the PBGC as well as Unsecured Creditors Committee regarding their intention to terminate the Enron Plan, subject to approval by such parties, the bankruptcy court and authorization to fully fund the Enron Plan in accordance with its terms. If approved Enron would fully fund the Enron Plan in accordance with the terms, the plan could be terminated without any liability to Mariner. Enron has also stated that it believes it has the necessary funds to consummate such a termination. In addition to the extent that entities in the Controlled Group are sold prior to termination of the Plan, proceeds of the sale of such entities may be available to satisfy this liability. Enron estimates proceeds from such sale of Enron Control Group entities would far exceed any plan obligations.

NOTES TO FINANCIAL STATEMENTS -- (CONTINUED)

Retiree Health Benefits - Under COBRA, if certain retirees of Enron lose coverage under Enron's group health plan due to Enron's bankruptcy proceedings, they would be entitled to elect continuation of their health coverage in a group plan maintained by Enron or a member of its Controlled Group. Mariner's employees have not participated in this plan. Mariner management understands, based on discussions with Enron management, that Enron had provided a plan for retiree health insurance and that the actuarial liability for such coverage was approximately $70 million as of December 31, 2001. Management further understands that to meet its obligation, Enron, at December 31, 2001, had set aside approximately $34 million of assets in a VEBA trust, which may be protected under ERISA from Enron's creditors, leaving an unfunded liability of approximately $36 million.

In the event that Enron terminates its retiree group health plan, the retirees must be provided the opportunity to purchase continuing coverage from Enron's group health plan, if any, or the most appropriate existing group health plan of another member of the Enron Controlled Group. Retirees electing to purchase COBRA coverage would be provided the same coverage that is provided to similarly situated retirees under the appropriate existing plan. Retirees electing to purchase COBRA coverage would be required to pay for the coverage, up to an amount not to exceed 102% of the cost of coverage for similarly situated beneficiaries. Retirees are not required to purchase coverage under COBRA. Retirees may, instead, shop for coverage from third party sources and determine which is the least expensive coverage.

Management cannot predict the outcome of the above matter or estimate any potential loss. However, management believes that in the event Enron terminates coverage, any liability to Mariner associated with the number of retirees that choose to remain under Enron's retiree health plan will not be material. No reserves have been established by Mariner for any amounts related to this issue.

SALE OF ENRON INTEREST IN MARINER

On May 3, 2002, Enron presented to its Unsecured Creditors' Committee a proposal under which certain of Enron's core energy assets, including JEDI's ownership of Mariner Energy LLC, would be separated from Enron's bankruptcy estate and operated prospectively as a new integrated power and pipeline company.

On August 27, 2002, Enron announced that it had commenced a formal sales process for its interests in certain major assets, including JEDI's ownership of Mariner Energy LLC. In its announcement, Enron indicated that it was extending invitations to visit electronic data rooms containing information on 12 of its most valuable businesses, including Mariner, to a broad universe of potential bidders with whom Enron had executed confidentiality agreements.

Enron has announced its intent to move forward with the sale of four companies, however, it continues to evaluate its alternatives with regard to Mariner. Management is unable to give assurances that the Company will be or not be sold in the near future and there can be no assurance as to whether JEDI's ownership of Mariner Energy LLC will be sold in the future.

3. LIQUIDITY

As of December 31, 2002, we had working capital deficit of approximately $10.2 million, of which $15.2 million is restricted, compared to a working capital deficit of $19.6 million at December 31, 2001. The improvement in the working capital was primarily a result of the sale of half of the Company's working interest in its Falcon Project for approximately $52.3 million including reimbursements with a portion of the proceeds being used to repay the Revolving Credit Facility. We expect our 2003 capital expenditures, excluding capitalized indirect costs and proceeds from property conveyances (see "Note 4. Recent Events"), to be approximately $103.0 million, which would exceed cash flow from operations. However, we believe that cash on hand together with expected cash flow for operations to permit us to fund our remaining planned activities in 2003. There can be no assurance that our access to capital will be sufficient to meet our needs for capital. Accordingly, we may be required to reduce our planned capital expenditures and forego planned exploratory drilling.

The Company's Revolving Credit Facility matured in October 2002. We have begun discussions with other third party banks to provide a new revolving credit facility. There is no assurance that a new credit facility will be obtained. In addition, our parent, Mariner Energy LLC, is currently obligated under an unsecured term loan with an ENA affiliate. Mariner Energy LLC negotiated an extension of the ENA Affiliate Term Loan to March 20, 2004. In the event Mariner Energy LLC is unable to refinance or restructure its obligations prior to March 2004, Mariner Energy LLC would either default or be forced to sell its interest in the Company, or cause the Company to sell a substantial portion of its assets to repay its outstanding Senior Subordinated Notes so that it could distribute cash to Mariner Energy LLC to be used to repay the term loan. In the event of either a merger or consolidation of Mariner Energy LLC or the Company resulting in a change of control or a sale of all or substantially all of the Company's assets, holders of the Senior Subordinated Notes would have the right to require the Company to repurchase the Senior Subordinated Notes held by them at a purchase price in cash equal to 101% of the principal amount thereof plus accrued and unpaid interest. Any such transaction would also trigger a mandatory prepayment of all amounts outstanding under the ENA Affiliate Term Loan. The Company's ability to pay dividends and make other distributions of cash to Mariner Energy LLC are generally restricted under the indenture governing the Senior Subordinated Notes. As a result, following any change of control transaction or sale of all or substantially all of its assets, the Company would most likely be required to repurchase any Senior Subordinated Notes tendered to it under the indenture and redeem the balance of the Senior Subordinated Notes outstanding as permitted under the indenture before it could distribute cash to Mariner Energy LLC to repay the ENA Affiliate Term Loan.

4. RECENT EVENTS

On March 19, 2003, with bids totaling $3.9 million net to us, we were the apparent high bidder solely or with industry partners, on 11 out of 11 blocks on which we and our partners submitted bids in the Central Gulf of Mexico Oil and Gas Lease Sale 185 held on that date. Each of the blocks is in water depths ranging from approximately 20 feet to 1,500 feet. Mariner has a 100% working interest in five of the blocks and a 50% working interest in six blocks.

In January 2003 we made a deepwater Gulf of Mexico Discovery at "Harrier", East Breaks 759, and a shelf Gulf of Mexico discovery at Vermillion 144. Harrier was drilled in 4,100 feet of water to a total measured depth of 9,510 feet and encountered 315 net feet of gas pay. Mariner holds a 25% working interest. Vermilion 144 was drilled in 87 feet of water to a total measured depth of 16,522 feet and encountered 90 net feet of pay. Mariner is operator with a 42% working interest. First production is expected in June 2003.

In March 2003, we sold our remaining 25% working interest in our Falcon and Harrier discoveries and surrounding blocks, located in East Breaks area in the western Gulf of Mexico, for $121.6 million. We retained a 4 1/4 percent overriding royalty interest on seven non-producing blocks. The proceeds from the sale are expected to be used for debt reduction, capital expenditures, and other corporate purposes. At December 31, 2002, the Falcon project had 33.3 Bcfe assigned as proven oil and gas reserves to our interest.

5. LONG-TERM DEBT

REVOLVING CREDIT FACILITY - In 1996, the Company entered into an unsecured revolving credit facility (the "Revolving Credit Facility") with Bank of America as agent for a group of lenders (the "Lenders"). The Revolving Credit Facility provided for a maximum $150 million revolving credit loan. On October 1, 2002 the Revolving Credit Facility matured. This facility has not yet been replaced; however, management is in discussions with third party banks to provide a replacement facility.

10 1/2% SENIOR SUBORDINATED NOTES - On August 14, 1996, the Company completed the sale of $100 million principal amount of 10 1/2% Senior Subordinated Notes Due 2006, (the "Notes"). The proceeds of the Notes were used by the Company to (i) pay a dividend to Mariner Holdings, which used the dividend to fully repay a bridge loan from JEDI incurred in the Acquisition, and (ii) repay a previous revolving credit facility. The Notes bear interest at 10 1/2% payable semiannually in arrears on February 1 and August 1 of each year. The Notes are unsecured obligations of the Company, and are subordinated in right of payment to all senior debt (as defined in the indenture governing the Notes) of the Company.

The indenture pursuant to which the Notes are issued contains certain covenants that, among other things, limit the ability of the Company to incur additional indebtedness, pay dividends, redeem capital stock, make investments, enter into transactions with affiliates, sell assets and engage in mergers and consolidations. As of December 31, 2002, the Company was in compliance with all such requirements.

The Notes are redeemable at the option of the Company, in whole or in part, at any time on or after August 1, 2001, initially at 105.25% of their principal amount, plus accrued interest, declining ratably to 100% of their principal amount, plus accrued interest, on or after August 1, 2003.

In the event of a change of control of the Company (as defined in the indenture pursuant to which the Notes are issued), each holder of the Notes (the "Holder") will have the right to require the Company to repurchase all or any portion of such Holder's Notes at a purchase price equal to 101% of the principal amount thereof, plus accrued interest.

Cash paid for interest for the years ending December 31, 2002, 2001 and 2000 was $11.1, $11.4 million, $15.3 million, respectively.

6. STOCKHOLDER'S EQUITY

STOCK OPTION PLAN - During June 1996, Mariner Holdings established the Mariner Holdings, Inc. 1996 Stock Option Plan (the "Plan") providing for the granting of stock options to key employees and consultants. Options granted under the Plan must not be less than the fair market value of the shares at the date of grant. The maximum number of shares of Mariner Holdings common shares that may be issued under the Plan was 142,800. In June 1998, the Plan was amended to increase the number of eligible shares to be issued to 202,800. In September 1998, concurrent with the exchange of each common share of Mariner Holdings for twelve common shares of Mariner Energy LLC, the Plan was amended to make Mariner Energy LLC the Plan sponsor. The maximum number of shares of common shares that can be issued under the Plan was correspondingly increased to 2,433,600.

During the years ended December 31, 2002, 2001 and 2000, Mariner Energy LLC granted stock options ("Options") of 0, 13,166, and 39,144, respectively. No options have been exercised, but 212,882 options have been canceled during the three year period. At December 31, 2002, options to purchase 1,926,468 shares were outstanding at an exercisable. The exercise price for outstanding options to purchase an aggregate of 1,574,244 shares under the 1996 plan is $8.33 per share, and the exercise price for options to purchase the remaining outstanding aggregate of 352,224 shares under the 1996 plan is $14.58 per share. These Options generally become exercisable as to one-fifth to one-third on each of the first three to five anniversaries of the date of grant. The Options expire from seven years to ten years after the date of grant. All of the 1,574,244 options issued at $8.33 will expire in June 2003. The remaining options expire in various months between 2008 through 2010.

The Company applies APB Opinion 25 and related interpretations in accounting for the Plan. Accordingly, no compensation cost has been recognized for the Plan. Had compensation cost for the Plan been determined based on the fair value at the grant date for awards under the Plan consistent with the method of SFAS No. 123, the Company's net income for the year ended December 31, 2002 would not have changed, the net income for the year ending 2001 would have decreased $325,000 and the net income for the year ending 2000 would have decreased $422,000, respectively. Pro forma earnings per share would be $21,734, $8,744 and $15,535 for the years ending December 31, 2002, 2001 and 2000, respectively. The effects of applying SFAS No. 123 in this pro forma disclosure are not indicative of future amounts. The fair value of each option grant is estimated on the date of grant using a present value calculation, risk free interest of 4.54% and 4.75% for the years ending December 31, 2001 and 2000, respectively. No options were granted in 2002. Stock options available for future grant amounted to 507,132 shares at December 31, 2002. Exercisable stock options amounted to 1,926,468 shares at December 31, 2002.

7. EMPLOYEE BENEFIT AND ROYALTY PLANS

EMPLOYEE CAPITAL ACCUMULATION PLAN - The Company provides all full-time employees participation in the Employee Capital Accumulation Plan (the "Plan") which is comprised of a contributory 401(k) savings plan and a discretionary profit sharing plan. Under the 401(k) feature, the Company, at its sole discretion, may contribute an employer-matching contribution equal to a percentage not to exceed 50% of each eligible participant's matched salary reduction contribution as defined by the Plan. Under the discretionary profit sharing contribution feature of the Plan, the Company's contribution, if any, must be determined annually and must be 4% of the lesser of the Company's operating income or total employee compensation and shall be allocated to each eligible participant pro rata to his or her compensation. During 2002, 2001 and 2000, the Company contributed $249,205, $369,677 and $291,940, respectively, to the Plan. This plan is a continuation of a plan provided by the Predecessor Company.

OVERRIDING ROYALTY INTERESTS - Pursuant to agreements, certain key employees and consultants are entitled to receive, as incentive compensation, overriding royalty interests ("Overriding Royalty Interests") in certain oil and gas prospects acquired by the Company. Such Overriding Royalty Interests entitle the holder to receive a specified percentage of the gross proceeds from the future sale of oil and gas (less production taxes), if any, applicable to the prospects. Cash payments made by the Company under these agreements for the three years ended December 31, 2002, 2001 and 2000 were $2.5, $5.8 and $2.9 million, respectively.

8. COMMITMENTS AND CONTINGENCIES

ENRON MATTERS - See "Note 2. Related-Party Transactions", the Company has various related-party transactions and certain control relationships with Enron Corp. and affiliates.

MINIMUM FUTURE LEASE PAYMENTS - The Company leases certain office facilities and other equipment under long-term operating lease arrangements. Minimum rental obligations under the Company's operating leases in effect at December 31, 2002 are as follows (in thousands):

2003...................	$ 645
2004...................	611
2005...................	547
2006...................	445
2007...................	9
TOTAL..............	$ 2,257

Rental expense, before capitalization, was approximately $1,723,000, $1,492,000 and $1,228,000 for the years ended December 31, 2002, 2001 and 2000, respectively.

HEDGING PROGRAM -The energy markets have historically been very volatile, and there can be no assurance that oil and gas prices will not be subject to wide fluctuations in the future. In an effort to reduce the effects of the volatility of the price of oil and natural gas on our operations, management has adopted a policy of hedging oil and natural gas prices from time to time primarily through the use of commodity swap and costless collar agreements. While the use of these hedging arrangements limits the downside risk of adverse price movements, it also limits future gains from favorable movements. Prior to 2002 all hedge activities historically have been conducted with Enron. As a result of the Enron bankruptcy we have de-designated all hedge positions (see "Note 2 - Related-Party Transactions"). In 2002 we implemented a new hedging program with a third party.

On June 28, 2002 the Company commenced price risk activities with a third party. These activities are intended to manage the Company's exposure to fluctuations in commodity prices for natural gas and crude. As of December 31, 2002 the Company had the following fixed price swaps outstanding.

TIME PERIOD	NOTIONAL QUANTITIES	FIXED PRICE	DECEMBER 3 FAIR V (milli Gain/(
CRUDE OIL (MBbl)			
January 1 - December 31, 2003			
Fixed Price Swap	548	$ 24.02	$ (1
Fixed Price Swap	183	$ 24.81	(0
NATURAL GAS (MMbtu)			
January 1 - December 31, 2003			
Fixed Price Swap	730	$ 3.54	(
Fixed Price Swap	730	$ 3.60	(
			$ (1

The Company has reviewed the financial strength of its counterparts and believes credit risk to be minimal. As of December 31, 2002 the Company had on deposit, classified as restricted cash, $22.3 million with the third party for collateral. This collateral included $5.8 million in initial margin in cash and $16.5 million in mark-to-market exposure. Initial margin decreases as contracts settle.

As a result of increasing natural gas prices, in January and February of 2003, the Company unwound, through the purchase of counter positions, all natural gas swap contracts for the months of February through October 2003 locking in a loss of $23.2 million. This loss will be settled over the original contract period.

As a result of these swaps and other hedging transactions the Company will have approximately 31% of 2003 production subject to hedges. Mark to market value changes approximately $8.6 million for every 10% overall change in commodity prices.

The following table sets forth the results of hedging transactions during the periods indicated that were made with non-Enron related parties.

	DECEMBER 31, 2002	2001

NATURAL GAS		
Quantity hedged (Mmbtu)	--	--
Increase (Decrease) in Natural Gas Sales (in thousands)	--	--
CRUDE OIL		
Quantity hedged (MBbls)	169	--
Increase (Decrease) in Crude Oil Sales (in thousands)	$ (325)	--

OTHER COMMITMENTS - In the ordinary course of business we enter into long-term commitments to purchase seismic data. The minimum annual payments under these contracts are $6.3 million in 2003 and $2.7 million in 2004.

DEEPWATER RIG - In the fourth quarter of 1999, Noble Drilling Corporation filed suit against the Company alleging breach of contract regarding a letter of intent for a five year Deepwater rig contract. In February 2000, both the Company and Noble Drilling Corporation entered into a settlement agreement whereby the Company committed to using this Deepwater rig for a minimum of 660 days over a five-year period at market-based day rates for comparable drilling rigs in comparable water depths subject to a floor day rate ranging from $65,000 to $125,000. In exchange for market-based day rates, Noble Drilling was assigned working interests in seven of the Company's deepwater exploration prospects. The Company will pay Noble Drilling's share of the costs of drilling the initial test well on each of these prospects. As of December 31, 2002, 43 days remained on this commitment and the Company has drilled five of the seven prospects.

MMS APPEAL - Mariner operates numerous properties in the Gulf of Mexico. Three of such properties were leased from the Mineral Management Service subject to the 1996 Royalty Relief Act. This Act relieved the obligation to pay royalties on certain predetermined leases until a designated volume is produced. These three leases contained language, which limited royalty relief if commodity prices exceeded predetermined levels. Beginning in January 2000 commodity prices exceeded the predetermined levels. Management believes the MMS did not have the authority to set pricing limits and the Company filed an administrative appeal with the MMS and has withheld royalties regarding this matter. The Company has recorded a liability for 100% of the exposure on this matter which on December 31, 2002 was $5.5 million.

LITIGATION - The Company, in the ordinary course of business, is a claimant and/or a defendant in various legal proceedings, including proceedings as to which the Company has insurance coverage. The Company does not consider its exposure in these proceedings, individually and in the aggregate, to be material.

9. INCOME TAXES

The following table sets forth a reconciliation of the statutory federal income tax with the income tax provision (in thousands):

YEAR ENDING DECEMBER 31,

	2002		2001		
	$	%	$	%	$
Income before income taxes...............	29,993	--	12,393	--	21,8
Income tax expense (benefit) computed at statutory rates......................	10,498	35	4,338	35	7,6
Change in valuation allowance............	(11,507)	(38)	(4,544)	(37)	(8,7
Other..................................	1,009	3	206	2	1,0
Tax Expense............................	--	--	--	--	

No federal income taxes were paid by the Company during the years ended December 31, 2002, 2001 and 2000.

The Company's deferred tax position reflects the net tax effects of the temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax reporting. Significant components of the deferred tax assets and liabilities are as follows (in thousands):

	YEAR ENDING DECEM	
	2002	2001
DEFERRED TAX ASSETS:		
Net operating loss carry forwards............................	$ 21,025	$ 21,618
Differences between book and tax basis of receivables.........	3,160	10,335
Valuation allowance..	(7,090)	(18,597)
Total net deferred tax assets..........................	17,095	13,356
DEFERRED TAX LIABILITIES:		
Differences between book and tax basis of properties..........	(17,095)	(13,356)
Total net deferred taxes..............................	--	--

As of December 31, 2002, the Company had a cumulative net operating loss carryforward ("NOL") for federal income tax purposes of approximately $60.1 million, which begins to expire in the year 2012. A valuation allowance is recorded against tax assets which are not likely to be realized. Because of the uncertain nature of their ultimate realization, as well as past performance and the NOL expiration date, the Company has established a valuation allowance against this NOL carryforward benefit and for all net deferred tax assets in excess of net deferred tax liabilities.

10. OIL AND GAS PRODUCING ACTIVITIES AND CAPITALIZED COSTS

The results of operations from the Company's oil and gas producing activities were as follows (in thousands):

	YEAR ENDING DECEMBER 31,		
	2002	2001	2000
Oil and gas sales..............................	$ 158,228	$ 155,000	$121,15
Production costs...............................	26,076	(20,063)	(17,19
Transportation.................................	10,480	(12,011)	(7,78
Depreciation, depletion and amortization.........	70,821	(63,503)	(56,84
Results of operations.......................	$ 50,851	$ 59,423	$ 39,32

Costs incurred in property acquisition, exploration and development activities were as follows (in thousands, except per equivalent mcf amounts):

	YEAR ENDING DECEMBER 31,	
	2002	2001
Property acquisition costs		
Unproved properties	$ --	$ 8,721
Exploration costs	40,358	57,665
Development costs	65,002	96,999
Proceeds from property conveyances........................	(52,329)	(90,500)
Total costs, net of proceeds from property conveyances.	$ 53,031	$ 72,885
Depreciation, depletion and amortization rate per equivalent Mcf before impairment..........................	$ 1.78	$ 1.73

The Company capitalizes internal costs associated with exploration activities in progress. These capitalized costs were approximately $1,022,000, $10,508,000 and $11,625,000 for the years ended December 31, 2002, 2001 and 2000, respectively.

The following table summarizes costs related to unevaluated properties which have been excluded from amounts subject to amortization at December 31,

2002. The Company regularly evaluates these costs to determine whether impairment has occurred. The majority of these costs are expected to be evaluated and included in the amortization base within three years.

	COST INCURRED DURING THE YEAR ENDED DECEMBER 31,			
	2002	2001	2000	PRIOR
Property acquisition costs......	$ 16,289	$ 8,912	$ 2,527	$ 9,672
Exploration costs...............	1,834	5,380	--	16
Total	18,123	$14,292	$ 2,527	$ 9,688

All of the excluded costs at December 31, 2002 relate to activities in the Gulf of Mexico.

11. SUPPLEMENTAL OIL AND GAS RESERVE AND STANDARDIZED MEASURE INFORMATION (UNAUDITED)

Estimated proved net recoverable reserves as shown below include only those quantities that are expected to be commercially recoverable at prices and costs in effect at the balance sheet dates under existing regulatory practices and with conventional equipment and operating methods. Proved developed reserves represent only those reserves expected to be recovered through existing wells. Proved undeveloped reserves include those reserves expected to be recovered from new wells on undrilled acreage or from existing wells on which a relatively major expenditure is required for recompletion. Also included in the Company's proved undeveloped reserves as of December 31, 2002 were reserves expected to be recovered from wells for which certain drilling and completion operations had occurred as of that date, (See "Note 4. Recent Events" regarding sale of our remaining working interest in the Falcon project subsequent to December 31, 2002) but for which significant future capital expenditures were required to bring the wells into commercial production.

Reserve estimates are inherently imprecise and may change as additional information becomes available. Furthermore, estimates of oil and gas reserves, of necessity, are projections based on engineering data, and there are uncertainties inherent in the interpretation of such data as well as in the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of

estimating underground accumulations of oil and natural gas that cannot be measured exactly, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Accordingly, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of the future net cash flows expected therefrom prepared by different engineers or by the same engineers at different times may vary substantially. There also can be no assurance that the reserves set forth herein will ultimately be produced or that the proved undeveloped reserves set forth herein will be developed within the periods anticipated. It is likely that variances from the estimates will be material. In addition, the estimates of future net revenues from proved reserves of the Company and the present value thereof are based upon certain assumptions about future production levels, prices and costs that may not be correct when judged against actual subsequent experience. The Company emphasizes with respect to the estimates prepared by independent petroleum engineers that the discounted future net cash flows should not be construed as representative of the fair market value of the proved reserves owned by the Company since discounted future net cash flows are based upon projected cash flows which do not provide for changes in oil and natural gas prices from those in effect on the date indicated or for escalation of expenses and capital costs subsequent to such date. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based. Actual results will differ, and are likely to differ materially, from the results estimated.

ESTIMATED QUANTITIES OF PROVED RESERVES
(IN THOUSANDS)

	OIL (BBL)	NATURAL GAS (MCF)	NA E
DECEMBER 31, 1999	9,927	118,790	
Revisions of previous estimates	324	(13,255)	
Extensions, discoveries and other additions	4,123	24,649	
Sale of reserves in place	(215)	(673)	
Purchase of reserves in place	--	25,455	
Production	(1,762)	(25,710)	
DECEMBER 31, 2000	12,387	129,256	
Revisions of previous estimates	2,079	(8,240)	
Extensions, discoveries and other additions	2,736	96,711	
Sale of reserves in place	(4,123)	(22,470)	
Production	(2,978)	(18,796)	
DECEMBER 31, 2001	10,101	176,461	
Revisions of previous estimates	541	5,523	
Extensions, discoveries and other additions	2,108	18,791	
Sale of reserves in place	(35)	(35,088)	
Production	(1,697)	(29,632)	
DECEMBER 31, 2002	11,018	136,055	

MARINER ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS -- (CONTINUED)

ESTIMATED QUANTITIES OF PROVED DEVELOPED RESERVES
(IN THOUSANDS)

	OIL (BBL)	NATURAL GAS (MCF)	NATURAL G EQUIVALE (MCFE)
December 31, 2000	5,540	61,623	94,863
December 31, 2001	4,675	44,040	72,090
December 31, 2002	3,609	64,586	86,240

The following is a summary of a standardized measure of discounted net cash flows related to the Company's proved oil and gas reserves. The information presented is based on a valuation of proved reserves using discounted cash flows based on year-end prices, costs and economic conditions and a 10% discount rate. The additions to proved reserves from new discoveries and extensions could vary significantly from year to year. Additionally, the impact of changes to reflect current prices and costs of reserves proved in prior years could also be significant. Accordingly, the information presented below should not be viewed as an estimate of the fair value of the Company's oil and gas properties, nor should it be considered indicative of any trends.

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STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS
(IN THOUSANDS)

	YEAR ENDING DECEMBER 3	
	2002	2001
Future cash inflows	$ 992,700	$ 615,131
Future production costs	(154,661)	(149,636)
Future development costs	(110,474)	(145,243)
Future income taxes	(72,648)	--
Future net cash flows	654,917	320,252
Discount of future net cash flows at 10% per annum	(191,345)	(88,224)
Standardized measure of discounted future net flows	463,572	$ 232,028

During recent years, there have been significant fluctuations in the prices paid for crude oil in the world markets and in the United States, including the posted prices paid by purchasers of the Company's crude oil. The weighted average prices of oil and gas at December 31, 2002, 2001 and 2000, used in the above table, were $29.34, $16.40 and $26.36 per Bbl, respectively, and $5.09, $2.60 and $11.32 per Mcf, respectively, and do not include the effect of hedging contracts in place at period end.

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

	YEAR ENDING DECEMBER 31,		
	2002	2001	2000
Sales and transfers of oil and gas produced, net of production costs	(125,610)	$(122,053)	$(96,169)
Net changes in prices and production costs	331,085	(661,871)	503,871
Extensions and discoveries, net of future development and production costs	50,085	130,512	214,022
Development costs during period and net change in development costs	28,474	40,674	39,736
Revision of previous quantity estimates	7,480	(106,813)	(13,365)
Purchases of reserves in place		--	157,657
Sales of reserves in place	(25,887)	(172,072)	(2,584)
Net change in income taxes	(51,423)	270,510	(270,510)
Accretion of discount before income taxes	29,488	104,320	29,678
Changes in production rates (timing) and other	(12,148)	(23,884)	(857)
Net change	$ 231,544	$(540,677)	$561,479

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

None

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PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Set forth below are the names, ages and positions of our executive officers and directors and a key consultant as of March 4, 2003. All directors are elected for a term of one year and serve until their successors are elected and qualified. All executive officers hold office until their successors are elected and qualified.

Name	Age	Position with the Company
Scott D. Josey	45	Chairman of the Board and Chief Executive Officer

Judd Hansen	47	Vice President
David S. Huber	52	Consultant and Sr. Vice President
Cory L. Loegering	47	Vice President - Deepwater Operations
Dalton F. Polasek	51	Sr. Vice President
Mike C. van den Bold	40	Vice President - Development
Michael A. Wichterich	35	Vice President - Finance & Administration
Raymond M. Bowen, Jr.	43	Director
Craig A. Fox	47	Director
Michael S. McConnell	43	Director
Jesus G. Melendrez	43	Director
Greg F. Piper	40	Director

Mr. Josey is the Chairman of the Board and Chief Executive Officer of Mariner Energy, Inc. From 2000 to 2002, Mr. Josey served as Vice President and Co-Manager of Enron Energy Capital Resources, which provided debt, mezzanine, and equity capital to energy companies. From 1995 to 2000, Mr. Josey was the managing partner of Sagestone Capital, which provided investment-banking services to the oil and gas industry and portfolio management services to Commonfund Capital, a fund of funds for endowments and foundations. From 1993 to 1995, Mr. Josey was a Director with Enron Capital & Trade Resources Corp. in its energy investment group. From 1982 to 1993, Mr. Josey was with Texas Oil and Gas Corp., where he worked in all phases of its drilling, production, pipeline, corporate planning and commercial activities. Mr. Josey is a member of the Society of Petroleum Engineers and the Independent Producers Association of America. Mr. Josey received his BS in mechanical engineering from Texas A&M University, his MBA from the University of Texas, and his MS in petroleum engineering from the University of Houston.

Mr. Hansen has served as Vice President of Mariner Energy, Inc. since September 2002. Mr. Hansen has served as Manager of Drilling and Operations of Aeon Exploration Company since its inception in 2001. He was employed as Operations Manager, Gulf Coast Division for Basin Exploration, Inc. from November 1997 until it was merged with Stone Energy in February 2001. From 1991 to 1997, he was employed in various engineering positions at Greenhill Petroleum Corporation, including Senior Production Engineer and Workover/Completion Superintendent. He began his career in 1978 as a Drilling Engineer for Shell Oil Company.

Mr. Huber, a consultant, began his association with us in 1991 as a deepwater project management consultant and is presently a Sr. Vice President over the Deepwater department. Prior to joining us, Mr. Huber was employed by Hamilton Oil Corporation in the North Sea from 1981 to 1991, holding positions of production manager, planning and economics manager, and engineering manager. He was the deepwater drilling engineering supervisor for Esso Exploration, Inc. from 1974 to 1980.

Mr. Loegering has been our Vice President of Deepwater Operations since August 2002. He has been active in exploration and production in the Gulf of Mexico since 1977. Cory began with Conoco in 1977 in the construction, production and reservoir departments. In 1982 he joined Tenneco and held the position of reservoir engineering supervisor and was later moved to a position of senior engineer in the economic, planning and analysis group. He joined Hardy Oil and Gas, now Mariner, in 1990. In 1992, Cory became active in deepwater with the formulation and implementation of Mariner's objective to become a deepwater operator. Cory holds a BS degree in Civil Engineering from Montana State University.

Mr. Polasek has been Sr. Vice President of Mariner Energy, Inc. since September 2002. Mr. Polasek has served as Vice President and Principal of Aeon Exploration Company since its inception in 2001. He served as Vice President of Gulf Coast Engineering for Basin Exploration, Inc. from 1996 until it was merged with Stone Energy in February 2001. From 1994 to 1996, he was employed by SMR Energy Income Funds as Vice President of Engineering. From 1991 to 1994, Mr. Polasek served as the director of Gulf Coast Acquisitions/Engineering for General Atlantic Resources. Prior to joining GA Resources, Mr. Polasek served as manager of planning and business development for Mark Producing Company from 1983 to 1991. He began his career in 1975 as a reservoir engineer for Amoco Production Company. Mr. Polasek is a Registered Professional Engineer in Texas and a member of the Independent Producers Association of America, the American Association of Drilling Engineers and the American Petroleum Institute.

Mr. van den Bold has been our Vice President of Development since October 2001. Prior to obtaining his position, he was a Senior Development Geologist. He was previously employed at British Borneo and British Petroleum from 1986 through 2000 in various exploration and development positions. He received his BS and MS degrees in geology from the Louisiana State University.

Mr. Wichterich has been our Vice President of Finance and Administration since September 2001. Prior to obtaining this position he was the Company's Corporate Controller from 1998 through August 2001. He was previously employed at PricewaterhouseCoopers from 1989 through 1998 with ending title of Senior Manager.

Mr. Bowen has served as a director since January 2000. He is currently Executive Vice President and Chief Financial Officer of ENA and has held various management positions with ENA since 1996. Prior to joining ENA, Mr. Bowen was a Vice President and Senior Banker in Citicorp's Petroleum, Metals and Mining Department in Houston.

Mr. Fox is currently Senior Vice President and Senior Engineer at the Royal Bank of Scotland; prior to this position he was Vice President and Technical Manager for Enron Energy Capital Resources. Mr. Fox received his bachelor's of science degree in mechanical engineering from Texas A&M University in 1977. He was employed with Houston Oil & Minerals, Tenneco Oil Company, and Sandefer Oil & Gas as a reservoir and production engineer for 15 years before joining Enron Finance Corp. in 1992 as a Senior Reservoir Engineer. He became a Vice President in the engineering group supporting producer finance in 1995.

Mr. McConnell is Chairman and Chief Executive Officer of the Enron Generation and Production Group, which is responsible for unregulated businesses in North America. He also serves on the Executive Committee of Enron Corp. Mr. McConnell graduated from the University of Oklahoma in 1982 with a BBA in Petroleum Land Management with an emphasis on Law. He is a member of the Price Business School Board of Advisors for the University of Oklahoma and is currently serving on several Boards of Directors.

Mr. Melendrez is a Vice President of ENA and is responsible for the execution and structuring of upstream transactions. Prior to joining ENA in 1999, Mr. Melendrez was Sr. Vice President of Enserch Energy Services, Inc. He has held financial positions with several Enron affiliates since the early 1990's that involved loan restructuring and power marketing.

Mr. Piper is Managing Director of Enron North America and President and Chief Operating Officer of the Generation and Production Group. Prior to his current position, Mr. Piper was Managing Director and Chief Information Officer of Enron Corp. Mr. Piper graduated from the Colorado School of Mines in 1986 with a Bachelor of Science degree in Petroleum Engineering and graduated from the University of Texas in 1997 with a Masters in Business Administration.

The Shareholders' Agreement requires that the Board of Directors include at least three nominees of the Management Stockholders. The remaining board members are to include nominees of JEDI. See "Certain Relationships and Related Transactions on page 72.

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ITEM 11. EXECUTIVE COMPENSATION

SUMMARY COMPENSATION TABLE

The following table sets forth the annual compensation for Mariner's Chief Executive Officer and the four other most highly compensated executive officers for the three fiscal years ended December 31, 2002, two of which were no longer with the Company at year end. These individuals are sometimes referred to as the "named executive officers".

NAME AND PRINCIPAL POSITION	YEAR	ANNUAL SALARY	OTHER ANNUAL COMPENSATION (1)	CURRENT YEAR COMPENSATION UNDER OUR OVERRIDING ROYALTY PROGRAM (2)	AL COMPE
Scott D. Josey	2002	90,909	1,825	0	
Chairman of the Board &	2001	0	0	0	
Chief Executive Officer	2000	0	0	0	
Dave Huber	2002	0	0	1,120	
Sr. Vice President, Deepwater	2001	0	0	6,276	
	2000	0	0	5,003	
Mike Wichterich	2002	152,500	11,317	0	
Vice President of Finance	2001	127,797	8,773	0	
And Administration	2000	111,250	5,320	0	
Mike van den Bold	2002	152,500	10,228	0	
Vice President Exploration	2001	131,125	5,616	0	
	2000	59,000	750	0	
Cory Loegering	2002	145,200	9,221	462	
Vice President Deepwater	2001	128,999	4,992	2,641	
	2000	123,600	2,760	2,063	
Kelly Zelikovitz	2002	0	0	0	
Corporate Secretary and General	2001	0	0	0	
Counsel	2000	0	0	0	
Richard Clark	2002	46,873	0	1,232	
Senior Vice President	2001	250,000	6,800	7,043	
	2000	235,000	3,680	5,596	

(1) Amounts shown reflect our contribution under the discretionary profit sharing feature of its Employee Capital Accumulation Plan. See "--401(k) Plan". For each of the named executive officers, the aggregate amount of perquisites and other personal benefits did not exceed the lesser of $50,000 or 10% of the officer's total annual salary and bonus and information with respect thereto is not included.

(2) These amounts include the value conveyed during the applicable year attributable to overriding royalty interests assigned to the named executive officer during the applicable year and distributions received, if any, during the applicable year attributable to overriding royalty interests assigned to the named executive officers during the applicable year. For information on overriding royalty payments received during the applicable year attributable to overriding royalty interests assigned to the named executive officer during past years, see the table below under "Overriding Royalty Program." These amounts also do not include amounts received during the applicable year as a result of sales of overriding royalty interests by individuals, normally in connection with sales of properties by us. No such sales were made in 2002, 2001 or 2000.

(3) Amounts shown reflect insurance premiums paid by us with respect to term life insurance for the benefit of the named executive officers and any performance bonuses, severance payments and contract fees paid during the year. In addition for Mr. Josey, the amounts also incurred payable to Enron North America under a Services Agreement . Mr. Josey, in 2002, became an employee of Mariner and is no longer working through the Services Agreement.

OPTIONS

None of the named executive officers exercised stock options in 2002. The following table shows the number and value of options owned by our named executive officers at December 31, 2002. All of the options described in the table below have been issued under the Mariner Energy LLC 1996 Stock Option Plan.

	NUMBER OF COMMON SHARES UNDERLYING UNEXERCISED OPTIONS AT DECEMBER 31, 2001	
	EXERCISABLE	UNEXERCISABLE
Dave Huber........................	17,136	0
Mike Wichterich...................	20,568	0
Mike van den Bold.................	8,232	0
Cory Loegering....................	48,456	0
Richard Clark.....................	167,928	0

Under the Mariner Energy LLC 1996 Stock Option Plan, a committee of the board of directors is authorized to grant options to purchase common shares, including options qualifying as "incentive stock options" under Section 422 of the Internal Revenue Code and options that do not so qualify, to employees and consultants as additional compensation for their services to us. The 1996 plan is intended to promote our long-term financial interests by providing a means by which designated employees and consultants may develop a sense of proprietorship and personal involvement in our development and financial success. We believe that this encourages them to remain with and devote their best efforts to our business and to advance the mutual interests of our shareholders and us. A total of 2,433,600 common shares may be issued under options granted under the 1996 plan, subject to adjustment for any share split, share dividend or other change in the common shares or our capital structure. Options to purchase 1,926,468 common shares are outstanding under the 1996 plan, 1,926,468 of which are currently exercisable. The exercise price for outstanding options to purchase an aggregate of 1,574,244 shares under the 1996 plan is $8.33 per share, and the exercise price for options to purchase the remaining outstanding aggregate of 352,224 shares under the 1996 plan is $14.58 per share. Subject to the provisions of the 1996 plan, the compensation committee is authorized to determine who may participate in the 1996 plan, the number of shares that may be issued under each option granted under the 1996 plan, and the terms, conditions and limitations applicable to each grant. Subject to some limitations, the board of directors of Mariner Energy LLC is authorized to amend, alter or terminate the 1996 plan.

EMPLOYMENT AGREEMENTS AND OTHER ARRANGEMENTS

All named executive officers are either employees at will with no employment contracts or contractors with contract cancellable upon 30 days notice, who became employees at will before March 4, 2002. Prior to becoming an employee Mr. Josey and Mr. Keel performed services under a Service Agreement with ENA at $25,000 per month. Mr. Josey became an employee at will in September 2002. Ms. Zelikovitz and Mr. Huber were performing their services under month to month cancellable contracts. Ms. Zelikovitz resigned her position in December 2002.

The named executive officers are entitled to participate in any medical, dental, life and accidental death and dismemberment insurance programs and retirement, pension, ERISA severance, deferred compensation and other benefit programs instituted by us from time to time. The employees are also entitled to vacation, reimbursement of specified expenses. Mr. Huber, Mr. Wichterich, Mr. Loegering and Mr. van den Bold each have retention agreements which provide for the payments of $30,000, $25,000, $25,000 and $25,000, respectively, to be paid on June 23, 2003. Mr. Josey is currently in negotiating with the compensation committee to establish a retention agreement. The terms and conditions of this agreement have not been established.

If we terminate a named executive officer's or any other employee without cause, the named executive officer or employee will be entitled to, among other things the higher of:

a. One week of pay for every $10,000 increment in base salary, rounded up to the next $10,000 increment

b. One week of pay for every year of service rounded up to the next whole year

c. An equal amount of the combined a. and b. above upon the signing of a release of liability, or;

d. Any amounts owned under the our employee retention plan.

If a named executive officer's employment agreement is terminated by us for cause, we will have no obligation to that employee other than to:

- pay his salary through the day of termination;

- pay him the value of his benefits under the employment agreement through the month of termination

OVERRIDING ROYALTY PROGRAM

Employees participating in our overriding royalty program receive incentive compensation in the form of overriding royalty interests in some of the oil and natural gas prospects we acquired. The aggregate overriding royalty interests do not exceed 1.5% of our working interest in these prospects before well payout or 6% of our working interest in these prospects after payout. An employee receives overriding royalty interests equal to specified undivided percentages of our working interest percentage in prospects we acquired within the United States and U.S. coastal waters during the term of the employee's employment.

The overriding royalty interest percentage of our working interest to which each named executive officer is entitled for the period before well payout is one-fourth of the overriding royalty interest percentage for the period after well payout. These percentages currently range from .051562 % to .137500 % before payout and from .206250 % to .550000 % after payout for the named executive officers.

If we propose to sell or farm out all or a portion of our working interest in a prospect to an unaffiliated third party and we determine in good faith that our interest will not be marketable on satisfactory terms if marketed subject to the named executive officer's overriding royalty interest affecting the prospect, we may adjust the named executive officer's overriding royalty interest in the prospect. These adjustments are determined by a committee designated by our board of directors, at least half of the members of which are individuals who have been granted an overriding royalty interest by us. Some committee decisions require the approval of our board of directors. These adjustments apply only to the portion of our working interest sold or farmed out to a third party and do not affect the named executive officer's overriding royalty interest in the portion of a prospect retained by us.

We may also elect, within 60 days after the end of our fiscal year, to reduce a named executive officer's overriding royalty interest in prospects that we acquired during the fiscal year. We must base these reductions on the levels of exploration and development costs related to these prospects actually incurred during the fiscal year. With respect to certain deepwater prospects, we also may elect, in our sole discretion, to make other reductions and adjustments to the employee's overriding royalty interest based on estimated exploration levels and development costs to be incurred in connection with these deepwater prospects. We retain a right of first refusal to purchase any overriding royalty interest assigned to a named executive officer. This right applies to any third-party offer received by the named executive officer during or within one year after the named executive officer's employment is terminated.

The following table shows distributions received during the applicable year by the named executive officers who are participants in the plan from overriding royalty interests we granted to the officers during the last 15 years.

AGGREGATE CASH AMOUNTS RECEIVED
FROM PREVIOUSLY ASSIGNED
OVERRIDING

NAME	ROYALTY INTERESTS(1) 2001	2001	2000
Richard Clark...................	$333,429	$544,237	$260,577
Dave Huber......................	262,084	409,895	128,659
Cory Loegering..................	119,191	189,063	79,596

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(1) For information on the value conveyed and distributions received, if any, during the applicable year attributable to overriding royalty interests assigned to the named executive officer during the applicable year, see the table under "Summary Compensation Table". The above amounts only include payments made by the Company. Certain participants also receive overrides from third parties.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Mariner is an indirect wholly owned subsidiary of Mariner Energy LLC. The following table sets forth the name and address of the only shareholder of Mariner Energy LLC that is known by the Company to beneficially own more than 5% of the outstanding common shares of Mariner Energy LLC, the number of shares beneficially owned by such shareholder, and the percentage of outstanding shares of common shares of Mariner Energy LLC so owned, as of March 1, 1999. As of March 4, 2003, there were 13,928,308 common shares of Mariner Energy LLC outstanding.

TITLE OF CLASS	NAME AND ADDRESS OF BENEFICIAL OWNER	NATURE OF BENEFICIAL OWNERSHIP	AMOUNT PERCENT O
Common Stock of Mariner Energy LLC	Joint Energy Development Investments Limited Partnership (1) 1400 Smith Street Houston, Texas 77002	13,334,186	95.

JEDI primarily invests in and manages certain natural gas and energy related assets. JEDI's general partner is Enron Capital Management Limited Partnership, a Delaware limited partnership, whose general partner is Enron Capital Corp., a Delaware corporation and a wholly owned subsidiary of ENA, which is a wholly-owned subsidiary of Enron Corp. The general partner of JEDI exercises sole voting and investment power with respect to such shares.

The table appearing below sets forth information as of March 4, 2003, with respect common shares of Mariner Energy LLC beneficially owned by each of our directors, the named officers listed in the compensation table, a key consultant and all directors and executive officers and such key consultant as a group, and the percentage of outstanding common shares of Mariner Energy LLC so owned by each.

DIRECTORS, KEY CONSULTANT AND NAMED EXECUTIVE OFFICERS	AMOUNT AND NATURE OF BENEFICIAL OWNERSHIP (1)	PERCENT OF CLASS
David S. Huber..........................	61,440	*
Cory Loegering..........................	17,172	*
All directors and executive and consultant as a group (2 persons)......	78,612	*

* Less than one percent.

(1) All shares are owned directly by the named person and such person has sole voting and investment power with respect to such shares.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

THE ACQUISITION, THE SHAREHOLDERS' AGREEMENT AND RELATED MATTERS

Mariner Energy LLC, JEDI and each other shareholder of Mariner are parties to the Amended and Restated Shareholders' Agreement (as amended, the "Shareholders' Agreement").

Mariner Energy LLC has agreed to reimburse each Management Shareholder who paid for equity in Mariner's predecessor by assignment of overriding royalty interests for any additional taxes and related costs incurred by such Management Shareholder to the extent, if any, that the transfer of the overriding royalty interests does not qualify as a tax-free exchange under federal tax laws.

Enron and certain of its subsidiaries and other affiliates collectively participate in nearly all phases of the oil and natural gas industry and, therefore, compete with Mariner. In addition, ENA, JEDI and other affiliates of ENA have provided, and may in the future provide, and ECT Securities Limited Partnership, another affiliate of Enron, has assisted in arranging financing to non-affiliated participants in the oil and natural gas industry who are or may become competitors of Mariner. Because of these various possible conflicting interests, the Shareholders' Agreement includes provisions designed to clarify that generally Enron and its affiliates have no duty to make business opportunities available to Mariner and no duty to refrain from conducting activities that may be competitive with us.

Under the terms of the Shareholders' Agreement, Enron and its affiliates (which include, without limitation, ENA and JEDI) are specifically permitted to compete with Mariner, and neither Enron nor any of its affiliates has any obligation to bring any business opportunity to Mariner.

ENRON BANKRUPTCY - Commencing on December 2, 2001, Enron Corp. ("Enron") and certain of its affiliates, including Enron North America Corp. ("ENA"), filed voluntary petitions for bankruptcy protection. We have been informed that of our various direct or indirect owners, only Enron and ENA are debtors in the bankruptcy. We do not know at this time if any other owners will seek bankruptcy protection or what effect, if any, this may have on the ownership of Mariner Energy LLC which owns 100% of Mariner Holdings, Inc. (our direct parent) or on Joint Energy Development Investments Limited Partnership ("JEDI"), which owns approximately 96% of the issued and outstanding equity of

Mariner Energy LLC. Enron is the parent of ENA, and an affiliate of ENA is the general partner of JEDI. JEDI is 100% owned by Enron and affiliates of ENA. Accordingly, Enron may be deemed to control JEDI, Mariner Energy LLC, Mariner Holdings and us. Additionally, five of the Company's directors are officers of Enron or affiliates of Enron. Because of these various potentially conflicting interests, ENA, the Company, JEDI and the minority shareholders of Mariner Energy LLC have entered into an agreement that is intended to make clear that Enron and its affiliates have no duty to make business opportunities available to the Company.

Mariner Energy LLC's only asset is 100% of the common stock of Mariner Holdings, Inc., our direct parent. The only asset of Mariner Holdings is 100% of the common shares of Mariner.

Management cannot predict with certainty what impact Enron's bankruptcy may have on us. However, it does believe that our assets and liabilities will not become part of the Enron estate in bankruptcy. Although JEDI owns 96% of Mariner Energy LLC's common shares, we, as a separate corporation own or lease the assets used in its business and our management, separate from Enron, is responsible for our day-to-day operations. Contractual provisions restrict Enron access to our assets. We maintain our own accounting system as well as separate debt ratings. We maintain our own separate and complete cash management system and finance its operations separately from Enron, on both a short-term and long-term basis. We file a consolidated tax return with Mariner Energy LLC.

Notwithstanding the above, we may have potential exposure to certain liabilities and asset impairments as a result of Enron's bankruptcy. Portions following Enron-related disclosures are based on discussions with Enron's legal advisors and management, including members of our Board of Directors. Although our management has implemented with Enron's legal advisor and management a systematic method of identifying Enron matters which may have a material impact on us, management cannot provide any assurance as the completeness or accuracy of the information provided by or on behalf of Enron.

ORGANIZATION AND OWNERSHIP OF THE COMPANY - Through March 31, 1996, Hardy Oil & Gas USA Inc. (the "Predecessor Company") was a wholly-owned subsidiary of Hardy Holdings Inc., which is a wholly-owned subsidiary of Hardy Oil & Gas Plc ("Hardy Plc"), a company incorporated in the United Kingdom. Pursuant to a stock purchase agreement dated April 1, 1996, JEDI and ENA, together with members of management of the Predecessor Company, formed Mariner Holdings, Inc. ("Mariner Holdings"). Mariner Holdings then purchased from Hardy Holdings Inc. all of the issued and outstanding stock of the Predecessor Company for a purchase price of approximately $185.5 million (the "Acquisition"). After the Acquisition, the name of the Predecessor Company was changed to Mariner Energy, Inc. In October 1998, JEDI and other shareholders exchanged all of their common shares of Mariner Holdings, the Company's direct parent, for an equivalent ownership percentage in common shares of Mariner Energy LLC. Mariner Energy LLC owns 100% of Mariner Holdings.

The following chart represents our current ownership structure and affiliation with Enron entities.

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   Enron North     ____________________100%__________________    Enron Corp.
  America Corp.    _____                                       ------------------
------------------     |                                               |
        |              |                                               |
        |              |                                               |
        |              |                                               |
        |              |        ------------------                     |
        |              |________   JILP-LP, Inc.                       |
        |                       ------------------                     |
        |                                |                             |
        |                                |  (Asset Specific)           |
        |                                |                             |
        |                       ------------------                     |
        |                           Ponderosa                          |
        |                           Assets LP                         LP
        |                       ------------------                     |
        |                                |                             |
        |                                |  (Limited Partnership)      |
        |                                |                             |
------------------              ------------------                     |
   Enron Capital   _____GP_____    Enron Capital                       |
       Corp.           ________    Management LP                       |
------------------      |       ------------------                     |
                        |                |                             |
                        |               GP                             |
                        |                |                             |
------------------      |       ------------------                     |
   Enron Capital   _____|           Joint Energy                       |
 Management, LLC   ____SLP_____      Development   ___________________|
------------------              Investments (JEDI)
                                ------------------
                                         |
                                        96%
                                         |
                                ------------------              ------------------
                                     Mariner       _____4%_____   Employees and
                                   Energy, LLC                  Former Employees
                                ------------------              ------------------
                                         |
                                        100%
                                         |
                                ------------------
                                     Mariner
                                  Holdings, Inc.
                                ------------------
                                         |
                                        100%
                                         |
                                ------------------
                                     Mariner
                                   Energy, Inc.
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Subsequent to the Acquisition, Mariner Energy LLC, Mariner Holdings and Mariner have each entered into various financing and operating transactions with affiliates. In addition the Company may have from time to time engaged in various commercial transactions and have various commercial relationships with Enron and certain affiliates of Enron, such as holding and exploring, exploiting and developing joint working interests in particular prospects and properties and entering into other oil and gas related or financial transactions. Certain of the Company's third-party debt instruments and arrangements restrict the

Company's ability to engage in transactions with its affiliates, but those restrictions are subject to significant exceptions. The Company believes that its current agreements with Enron and its affiliates are, and anticipates that any future agreements with Enron and its affiliates will be, on terms no less favorable to the Company than would be obtained in an agreement with a third party. Below is a summary of key transactions between the Company and affiliate entities.

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MARINER ENERGY LLC

ENA Affiliate Term Loan - In March 2000, Mariner Energy LLC established an unsecured term loan with ENA to repay amounts outstanding under various affiliate credit facilities at Mariner Energy LLC and Mariner and to provide additional working capital. The additional working capital of $55 million was contributed to Mariner in 2000. The loan bears interest at 15%, which interest accrues and is added to the loan principal. Repayment of the balance of loan principal and accrued interest, which was approximately $164.4 million as of December 31, 2002, is due March 20, 2004. In conjunction with the loan agreement, two five-year warrants were issued to ENA providing the right to purchase up to 900,000 of common shares of Mariner Energy LLC for $0.01 per share.

Covenants in Mariner's Senior Subordinated Notes restrict the funds of Mariner that can be distributed to Mariner Energy LLC. Accordingly, Mariner Energy LLC is restricted in its ability to repay the unsecured Term Loan or to distribute earnings to its shareholders. In the event Mariner Energy LLC is unable to restructure or extend the maturity of its obligations prior to March 2004 it would either default under the Term Loan or be forced to sell its interest in Mariner or cause Mariner to sell a substantial portion of its assets to repay any outstanding Senior Subordinated Notes so that it could distribute any remaining cash proceeds to Mariner Energy LLC to be used to repay the Term Loan.

We have been informed by Enron's legal advisors and management that the Term Loan and warrants were transferred from ENA to an ENA affiliate, which affiliate is part of a finance structure formed by ENA. Because debt obligations of the finance structure are in default and ENA therefore does not have complete control over decisions made by the ENA affiliate, it may be difficult for Mariner Energy LLC to obtain any consents, waivers or amendments needed from the ENA affiliate in connection with the Term Loan or the warrants.

MARINER HOLDINGS, INC.

1998 Equity Investment - In June 1998, Mariner Holdings issued additional equity to its existing shareholders, including JEDI, for approximately $14.58 per share, for a net investment of $28.8 million, all of which was contributed to Mariner. Mariner Holdings paid approximately $1.2 million as a structuring fee, on a pro rata basis, to existing shareholders participating in this transaction. Approximately $1 million of this fee was paid to ECT Securities Limited Partnership.

MARINER ENERGY, INC.

Oil and Gas Production Sales to ENA or Affiliates - During the three years ending December 31, 2002, 2001 and 2000, sales of oil and gas production to ENA or affiliates were $56.4million, $50.2 million and $73.4 million, respectively. These sales were generally made on 1 to 3 month contracts. At the time ENA filed its petition for bankruptcy protection, the Company immediately ceased selling its physical production to ENA, however, we continued to sell our production to Bridgeline which ENA owned a minority interest. All amounts sold to this party have been collected. As of December 31, 2002, we had an outstanding receivable for $3 million from ENA. This amount was not paid as scheduled and is still outstanding. Mariner has submitted a proof of claim to the bankruptcy court for amounts owed to it by ENA. The Company has estimated 100% of this balance is uncollectible and has recorded a full allowance and related expense.

Management Activities - We engage in price risk management activities from time to time. These activities are intended to manage our exposure to fluctuations in commodity prices for natural gas and crude oil. We primarily utilize price swaps and costless collars as a means to manage such risk. Historically, all of our hedging contracts were with ENA. As a result of ENA's bankruptcy, the contracts are currently in default. The November 2001 through April 30, 2002 settlements for oil and gas have not been collected. In addition, on May 14, 2002, we elected under its Master Service Agreement with ENA to terminate all open contracts. The effect of this termination is to fix the nominal value on all remaining contracts on May 14, 2002. Subsequent to this termination, the value of all oil and natural gas unpaid hedge contracts was $7.7 million. We have estimated 100% of this balance is uncollectible and has recorded a full allowance. We have submitted a proof of claims to the bankruptcy court for amounts owed under this agreement. In accordance with Statement of Financial Accounting Standards ("SFAS") No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 137 and No. 138, we have de-designated our contracts effective December 2, 2001 and are recognizing all market value changes subsequent to such de-designation in our earnings. The value recorded up to the time of de-designation and included in Accumulated Other Comprehensive Income ("AOCI"), will reverse out of AOCI and into earnings as the original corresponding production, as hedged by the contracts, is produced. For the year ending December 31, 2002 approximately $23.2 million has reversed out to earnings. As of December 31, 2002, $2.6 million remained in AOCI to be reversed out to earnings.

The following table sets forth the results of hedging transactions during the periods indicated that were made with ENA (all amounts shown are non-cash items):

	YEAR ENDING DECEMBER 31,		
	2002	2001	2000
Natural gas quantity hedged (Mmbtu)	18,090	17,733	19,569
Increase (decrease) in natural gas sales (thousands)	$20,413	$ (5,523)	$(21,364)
Crude oil quantity hedged (MBbls)	446	752	1,059
Increase (decrease) in crude oil sales (thousands)	$ 2,787	$ 2,393	$(14,053)

Supplemental Affiliate Data - provided below is a supplemental balance sheet and income statement for affiliate entities:

BALANCE SHEET DATA	DECEMBER 31, 2002 AMOUNTS (IN MILLIONS)	DECEMBER 31, 2002 TOTAL	DECEMBER 31, 2001 AMOUNTS (IN MILLIONS)	DECEMBER 31, 2001 TOTAL
RELATED PARTY RECEIVABLE:				
Derivative Asset	$ --		$ 2.5	$ --
Settled Hedge Receivable	--		0.4	--
Oil and Gas Receivable	8.2	8.2	0.3	3.2
ACCRUED LIABILITIES:				
Transportation Contract	--	--	0.9	--
Service Agreement	0.6	0.6	0.3	1.2
STOCKHOLDER'S EQUITY:				
Common Stock	$ .001	--	$ .001	--
Additional Paid in Capital	$ 227.3		$227.3	
Accumulated other Comprehensive Income	$ 2.3	$229.6	$ 25.8	$253.1

INCOME STATEMENT DATA	YEAR ENDED DECEMBER 31 2002	YEAR ENDED DECEMBER 31 2001
Oil and Gas Sales	$ 56.4	$ 50.2
General and Administrative Expenses	0.4	0.2
Transportation Expenses	2.7	4.2
Unrealized loss and other non-cash derivative instrument adjustments	3.2	29.5

As a result of the Enron and ENA bankruptcies, among other implications, we may not be able to obtain credit from banks or trade vendors or enter into hedging arrangements on acceptable terms. To date, our operations have not been materially affected by the bankruptcies; however, our ability to enter into certain transactions including purchase or sale arrangements and to conduct significant capital programs may be affected in the future Oil and gas sales and the related accounts receivable for the year ending December 31, 2002 relate to sales made to a minority owed affiliate of Enron.

CONTROLLED GROUP LIABILITY

On November 12, 2002, Enron's legal advisors and management informed us that we may be an Enron Corp. Controlled Group Member as defined under the Employee Retirement Income Security Act of 1974 ("ERISA") due to Enron's indirect ownership interest in Mariner Energy LLC. Enron management has not made a final determination if we are in fact a Controlled Group Member. Because of numerous ownership issues within the Enron Group, we are unable to make our own determination as to whether we agree or disagree that we are a Controlled Group

Member. In the event we are a Controlled Group Member, we may have potential liability for certain employee benefit plan obligations of Enron discussed below.

Pension Plans - Applicable federal law authorizes the Pension Benefit Guaranty Corporation ("PBGC") to institute proceedings in federal district court for the termination of a pension plan if it determines the plan has failed to comply with minimum funding standards, the plan is or will be unable to pay benefits when due, or the failure to terminate the plan may reasonably be expected to unreasonably increase the possible long-run loss to the PBGC. Federal law also authorizes the sponsor of a pension plan to terminate the plan at a time when the plan is underfunded, subject to PBGC or court approval.

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Based on discussions with Enron management, it is our management's understanding that, as of December 31, 2001 the assets of Enron's pension plan (the "Enron Plan") were less than the present value of all accrued benefits by approximately $52 million on a SFAS No. 87 basis and approximately $182 million on a plan termination basis. Further, Enron's management has informed Mariner management that the PBGC has filed claims in the Enron bankruptcy cases. The claims are duplicative in nature, representing unliquidated claims for PBGC insurance premiums (the "Premium Claims") and unliquidated claims for due but unpaid minimum funding contributions (the "Contribution Claims") under the Internal Revenue Code of 1986, as amended (the "Tax Code") 29 U.S.C.Sections 412(a) and 1082 and claims for unfunded benefit liabilities (the "UBL" Claims"). Enron and the relevant sponsors of the defined benefit plans are current on their PBGC premiums and their contributions to the pension plans. Therefore, Enron has valued the Premium Claims and the Contribution Claims at $0. The total amount of the UBL Claims is $305.5 million (including $271 million for the Enron Plan). In addition Enron Management has informed Mariner Management that the PBGC has informally alleged in pleadings filed with the bankruptcy court that the UBL Claim related to the Enron Plan could increase by as much as 100%. PBGC has provided no support (statutory or otherwise) for this assertion and Enron Management disputes the validity of any such claim. Because the Enron Plan is under funded and Enron is in bankruptcy, in certain circumstances the Enron Plan may be terminated and taken control of by the PBGC upon approval of a Federal District Court.

Mariner's employees have not been participants in the Enron Plan. However, upon termination of a pension plan, all of the members of the controlled group of the plan sponsor become jointly and severally liable for the plan are under funding. The PBGC can demand payment from one or more of the members of the controlled group. If payment is not made, a lien in favor of the PBGC automatically arises against all of the assets of that member of the controlled group. The amount of the lien is equal to the lesser of the underfunding or 30% of the aggregate net worth of all of the Controlled Group members. In addition, if the sponsor of a pension plan does not timely satisfy its minimum funding obligation to the pension plan, once the aggregate missed amounts exceed $1 million, a lien in favor of the plan in the amount of the missed funding automatically arises against the assets of every member of the Controlled Group. In either case, the PBGC may file to perfect the lien and attempt to enforce it against the assets of members of the Enron controlled group. Mariner has been informed by Enron that Enron's management believes that the lien would be subordinate to prior perfected liens on the assets of the member of the controlled group. Based on discussions with Enron's management, Mariner's management understands that Enron has made all required contributions to date through October 15, 2002. Enron's management has advised us that it intends to make its next contribution, due in the first quarter of 2003.

Management cannot predict the outcome of the above matters or estimate any potential loss. In addition, if the PBGC did look solely to Mariner to pay any amount with respect to the Enron Plan, Mariner would exercise all legal rights, available to it to defend against such a demand and to recover any contributions from the other solvent members of the Controlled Group. No reserves have been established by Mariner for any amounts related to this issue.

Mariner has also been informed by Enron management that Enron has contacted the PBGC as well as Unsecured Creditors Committee regarding their intention to terminate the Enron Plan, subject to approval by such parties, the bankruptcy court and authorization to fully fund the Enron Plan in accordance with its terms. If approved Enron would fully fund the Enron Plan in accordance with the terms, the plan could be terminated without any liability to Mariner. Enron has also stated that it believes it has the necessary funds to consummate such a termination. In addition to the extent that entities in the Controlled Group are sold prior to termination of the Plan, proceeds of the sale of such entities may be available to satisfy this liability. Enron estimates proceeds from such sale of Enron Control Group entities would far exceed any plan obligations.

Retiree Health Benefits - Under COBRA, if certain retirees of Enron lose coverage under Enron's group health plan due to Enron's bankruptcy proceedings, they would be entitled to elect continuation of their health coverage in a group plan maintained by Enron or a member of its Controlled Group. Mariner's employees have not participated in this plan. Mariner management understands, based on discussions with Enron management, that Enron had provided a plan for retiree health insurance and that the actuarial liability for such coverage was approximately $70 million as of December 31, 2001. Management further understands that to meet its obligation, Enron, at December 31, 2001, had set aside approximately $34 million of assets in a VEBA trust, which may be protected under ERISA from Enron's creditors, leaving an unfunded liability of approximately $36 million.

In the event that Enron terminates its retiree group health plan, the retirees must be provided the opportunity to purchase continuing coverage from Enron's group health plan, if any, or the most appropriate existing group health plan of another member of the Enron controlled group. Retirees electing to purchase COBRA coverage would be provided the same coverage that is provided to similarly situated retirees under the appropriate existing plan. Retirees electing to purchase COBRA coverage would be required to pay for the coverage, up to an amount not to exceed 102% of the cost of coverage for similarly situated beneficiaries. Retirees are not required to purchase coverage under COBRA. Retirees may, instead, shop for coverage from third party sources and determine which is the least expensive coverage.

Management cannot predict the outcome of the above matter or estimate any potential loss. However, management believes that in the event Enron terminates coverage, any liability to Mariner associated with the number of retirees that choose to remain under Enron's retiree health plan will not be material. No reserves have been established by Mariner for any amounts related to this issue.

SALE OF ENRON INTEREST IN MARINER

On May 3, 2002, Enron presented to its Unsecured Creditors' Committee a proposal under which certain of Enron's core energy assets, including JEDI's ownership of Mariner Energy LLC, would be separated from Enron's bankruptcy estate and operated prospectively as a new integrated power and pipeline company.

On August 27, 2002, Enron announced that it had commenced a formal sales process for its interests in certain major assets, including JEDI's ownership of Mariner Energy LLC. In its announcement, Enron indicated that it was extending invitations to visit electronic data rooms containing information on 12 of its most valuable businesses, including Mariner, to a broad universe of potential bidders with whom Enron had executed confidentiality agreements.

Enron has announced its intent to move forward with the sale of four companies, however, it continues to evaluate its alternatives with regard to Mariner. Management is unable to give assurances that the Company will be or not be sold in the near future and there can be no assurance as to whether JEDI's ownership of Mariner Energy LLC will be sold in the future.

ITEM 14. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures. The Company's Chief Executive Officer and Vice President of Finance & Administration have evaluated the effectiveness of the Company's disclosure controls and procedures (as such term is defined in Rules 13a-14(c) and 15d-14(c) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"). Based on such evaluation, such officers have concluded that, as of the Evaluation Date, the Company's disclosure controls and procedures are effective in alerting them on a timely basis to material information relating to the Company required to be included in the Company's reports filed or submitted under the Exchange Act. Although the Company's Chief Executive Officer and Vice President - Finance & Administration have concluded that the disclosure controls and procedures are effective, disclosures relating to Enron and the effects of its bankruptcy on Mariner were provided by Enron's management and its legal advisors. The Chief Executive Officer and Vice President - Finance & Administration rely on the information they provide for disclosure purposes.

(b) Changes in Internal Controls. Since the Evaluation Date, there have not been any significant changes in the Company's internal controls or in other factors that could significantly affect such controls.

PART IV

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

(a) DOCUMENTS INCLUDED IN THIS REPORT:

1. FINANCIAL STATEMENTS and 2. FINANCIAL STATEMENT SCHEDULES

These documents are listed in the Index to Financial Statements in Item 8 hereof.

3. EXHIBITS

Exhibits designated by the symbol * have been previously filed on prior years Form 10-K. All exhibits not so designated are incorporated by reference to a prior filing as indicated.

Exhibits designed by the symbol ** are filed with this Annual Report on Form 10-K.

Exhibits designated by the symbol " are management contracts or compensatory plans or arrangements that are required to be filed with this report pursuant to this Item 14.

The Company undertakes to furnish to any stockholder so requesting a copy of any of the following exhibits upon payment to the Company of the reasonable costs incurred by Company in furnishing any such exhibit.

3.1*	Amended and Restated Certificate of Incorporation of the Registrant, as amended.
3.2*	Bylaws of Registrant, as amended.
4.1(a)	Indenture, dated as of August 1, 1996, between the Registrant and United States Trust Company of New York, as Trustee.
4.2(d)	First Amendment to Indenture, dated as of January 31, 1998, between the Registrant and United States Trust Company of New York, as Trustee.
4.3(a)	Note, dated August 12, 1996, in the principal amount of up to $45,000,000, made by the Registrant in favor of Nations Bank of Texas, N.A.
4.4(a)	Note, dated August 12, 1996, in the principal amount of up to $45,000,000, made by the Registrant in favor of Toronto Dominion (Texas), Inc.
4.5(a)	Note, dated August 12, 1996, in the principal amount of up to $30,000,000, made by the Registrant in favor of The Bank of Nova Scotia.
4.6(a)	Note, dated 12, 1996, in the principal amount of up to $30,000.000, made by the Registrant in favor of ABN AMRO Bank, N.V., Houston Agency.
4.7(a)	Form of the Registrant's 10 1/2% Senior Subordinated Note Due 2006, Series B.
4.8*	Credit and Subordination Agreement dated as of September 2, 1998 between Mariner Holdings, Inc. and Enron Capital & Trade Resources Corp.
4.9(f)	Amended and Restated Credit Agreement, dated June 28, 1999, among Mariner Energy, Inc., NationsBank of Texas, N.A., as Agent, Toronto Dominion (Texas), Inc., as Co-agent, and the financial institutions listed on schedule 1 thereto.
4.10(f)	Second Amended and Restated Credit Agreement, dated as of April 15, 1999, between Mariner Energy LLC and Enron North America Corp. (formerly Enron Capital & Trade Resources Corp.).
4.11(f)	Revolving Credit Agreement dated as of April 15, 1999, between Mariner Energy, Inc. and Enron North America Corp. (formerly Enron Capital & Trade Resources Corp.).
4.12(g)	Term Loan Agreement, dated March 21, 2000, between Mariner Energy LLC and Enron North America Corp.

4.12(h)	First Amendment to Term Loan Agreement between Mariner Energy LLC and ECTMI Trutta Holdings LP dated September 6, 2002
10.1*	Amended and Restated Shareholders' Agreement, dated October 12, 1998, among Mariner Energy LLC, Enron Capital & Trade Resources Corp., Mariner Holdings, Inc., Joint Energy Development Investments Limited Partnership and the other shareholders of Mariner Energy LLC.
10.2*	Gas Gathering Agreement, dated December 29, 1999, between MEGS LLC, Mariner Energy, Inc. and Burlington Resources.

10.3(f)	Amended and Restated Credit Agreement, dated June 28, 1999, between Mariner Energy and Bank of America, N.A.
10.10**	Retention Agreement between Mariner Energy Inc. and Dave Huber dated September 27, 2003.
10.11(a)[]	Mariner Holdings, Inc. 1996 Stock Option Plan (assumed by Mariner Energy LLC).
10.12(a)[]	Form of Incentive Stock Option Agreement (pursuant to the Mariner Holdings, Inc. 1996 Stock Option Plan, assumed by Mariner Energy LLC).
10.13**	List of executive officers who are parties to an Incentive Stock Option Agreement.
10.14(a)[]	Form of Nonstatutory Stock Option Agreement (pursuant to the Mariner Holdings, Inc. 1996 Stock Option Plan, assumed by Mariner Energy LLC).
10.15**	List of executive officers who are parties to a Nonstatutory Stock Option Agreement.
10.16(a)[]	Nonstatutory Stock Option Agreement, dated June 27, 1996, between the Registrant and David S. Huber.
10.23**	Retention Agreement between Mariner Energy Inc. and Mike Wichterich dated September 27, 2003.
10.28(g)	First Amendment to Amended and Restated Credit Agreement, dated December 31, 1999 by and among Mariner Energy, Inc., Bank of America, N.A., Toronto Dominion (Texas), Inc., Bank of Nova Scotia, and ABN-AMRO Bank, N.V.
10.29(g)[]	Second Amendment to Amended and Restated Consulting Services Agreement, effective as of January 1, 2000, between Mariner Energy, Inc. and David S. Huber.
10.30(g)[]	Third Amendment to Amended and Restated Consulting Services Agreement, effective as of March 4, 2002,

between Mariner Energy, Inc. and David S. Huber.

10.31**	Retention Agreement between Mariner Energy Inc. and Mike van den Bold dated September 27, 2003.
10.32**	Retention Agreement between Mariner Energy Inc. and Cory Loegering dated September 27, 2003.
10.39(g)	Corporate Services Agreement, dated August 23, 2001, between the Mariner Energy, Inc. and Enron North America Corp.
23.1**	Consent of Ryder Scott Company.
23.2**	Ryder Scott Company Letter of Estimated Proved Reserves dated March 6, 2002.
99.1	Certificate of Chairman of Board and Chief Executive Officer
99.2	Certificate of Vice President of Finance and Administration

(a) Incorporated by reference to the Company's Registration Statement on Form S-4 (Registration No. 333-12707), filed September 25, 1996.

(b) Incorporated by reference to Amendment No. 1 to the Company's Registration Statement on Form S-4 (Registration No. 333-12707), filed December 6, 1996.

(c) Incorporated by reference to Amendment No. 2 to the Company's Registration Statement on Form S-4 (Registration No. 333-12707), filed December 19, 1996.

(d) Incorporated by reference to the Company's Annual Report on Form 10-K for the year ended December 31, 1996 (Registration No. 333-12707) filed March 31, 1997.

(e) Incorporated by reference to the Mariner Energy LLC November 4, 1999 filing on Forms S-1 (Registration No. 333-87287).

(f) Incorporated by reference to the Mariner Energy, Inc. March 31, 2001, June 30, 2001 or September 30, 2001 quarterly filings on Form 10-Q.

(g) Incorporated by reference to the Mariner Energy Inc. December 31, 2001 annual filing on form 10-K.

(h) Incorporated by reference to the Mariner Energy, Inc. March 31, 2002, June 30, 2002 or September 30, 2002 quarterly filings on Form 10-Q.

(b) REPORTS ON FORM 8-K:

The Company filed no reports on Form 8-K during the quarter ended December 31, 2002.

GLOSSARY

The terms defined in this glossary are used throughout this annual report.

Bbl. One stock tank barrel, or 42 U.S. Gallons liquid volume, used herein in reference to crude oil, condensate or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas.

Bcfe. One billion cubic feet of natural gas equivalent (see Mcfe for equivalency).

"behind the pipe" Hydrocarbons in a potentially producing horizon penetrated by a well bore the production of which has been postponed pending the production of hydrocarbons from another formation penetrated by the well bore. These hydrocarbons are classified as proved but non-producing reserves.

2-D. (Two-Dimensional Seismic) -- Geophysical data that depicts the subsurface strata in two dimensions.

3-D. (Three-Dimensional Seismic) -- Geophysical data that depicts the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than can be achieved using 2-D seismic.

"development well" A well drilled within the proved boundaries of an oil or natural gas reservoir with the intention of completing the stratigraphic horizon known to be productive.

"exploitation well" Ordinarily considered to be a development well drilled within a known reservoir. The Company uses the word to refer to Deepwater wells which are drilled on offshore leaseholds held (usually under farmout agreements) where a previous exploratory well showing the existence of potentially productive reservoirs was drilled, but the reservoir was by-passed for development by the owner who drilled the exploratory well; Thus the Company distinguishes its development wells on its own properties from such exploitation wells.

"exploratory well" A well drilled in unproven or semi-proven territory for the purpose of ascertaining the presence underground of a commercial petroleum deposit and which can be contrasted with a "development well".

"farm-in" A term used to describe the action taken by the person to whom a transfer of an interest in a leasehold in an oil and gas property is made pursuant to a farmout agreement.

"farmout" The term used to describe the action taken by the person making a transfer of a leasehold interest in an oil and gas property pursuant to a farmout agreement.

"farmout agreement" A common form of agreement between oil and gas operators pursuant to which an owner of an oil and gas leasehold interest who is not desirous of drilling at the time agrees to assign the leasehold interest, or some portion of it, to another operator who is desirous of drilling the tract. The assignor in such a transaction may retain some interest in the property such as an overriding royalty interest or a production payment, and, typically, the assignee of the leasehold interest has an obligation to drill one or more wells on the assigned acreage as a prerequisite to completion of the transfer to it.

"generate" Generally refers to the creation of an exploration or exploitation idea after evaluation of seismic and other available data.

"infill well" A well drilled between known producing wells to better exploit the reservoir.

"lease operating expenses" The expenses of lifting oil or gas from a producing formation to the surface, and the transportation and marketing thereof, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs, ad valorem taxes and other expenses incidental to production, but not including lease acquisition, drilling or completion expenses or other "finding costs".

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet of natural gas.

MMBls. One million barrels of crude oil or other liquid hydrocarbons

Mcfe. One thousand cubic feet of natural gas equivalent (converting one barrel of oil to six Mcf of natural gas based on commonly accepted rough equivalency of energy content).

MMBTU. One million British thermal units.

MMcf. One million cubic feet of natural gas.

MMcfe. One million cubic feet of natural gas equivalent (see Mcfe for equivalency).

NYMEX. New York Mercantile Exchange.

"payout" Generally refers to the recovery by the incurring party to an agreement of its costs of drilling, completing, equipping and operating a well before another party's participation in the benefits of the well commences or is increased to a new level.

"present value of estimated future net revenues" An estimate of the present value of the estimated future net revenues from proved oil and gas reserves at a date indicated after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of federal income taxes. The estimated future net revenues are discounted at an annual rate of 10%, in accordance with Securities and Exchange Commission practice, to determine their "present value". The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties. Estimates of future net revenues are made using oil and natural gas prices and operating costs at the date indicated and held constant for the life of the reserves.

"producing well" or "productive well" A well that is producing oil or natural gas or that is capable of production without further capital expenditure.

"proved developed reserves" Proved developed reserves are those quantities of crude oil, natural gas and natural gas liquids that, upon analysis of geological and engineering data, are expected with reasonable certainty to be recoverable in the future from known oil and natural gas reservoirs under existing economic and operating conditions. This classification includes: (a) proved developed producing reserves, which are those expected to be recovered from currently producing zones under continuation of present operating methods; and (b) proved developed non-producing reserves, which consist of (i) reserves from wells that have been completed and tested but are not yet producing due to lack of market or minor completion problems that are expected to be corrected, and (ii) reserves currently behind the pipe in existing wells which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the well.

"proved reserves" The estimated quantities of crude oil, natural gas and other hydrocarbon 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.

"proved undeveloped reserves" Proved reserves that may be expected to be recovered from existing wells that will require a relatively major expenditure to develop or from undrilled acreage adjacent to productive units that are reasonably certain of production when drilled.

"royalty interest" An interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage or of the proceeds from the sale thereof. Such an interest generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalty interests may be either landowner's royalty interests, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalty interests, which are usually carved from the leasehold interest pursuant to an assignment to a third party or reserved by an owner of the leasehold in connection with a transfer of the leasehold to a subsequent owner.

"subsea tieback" A productive well that has its wellhead equipment located on the sea floor and is connected by control and flow lines to an existing production platform located in the vicinity.

"unitized" or "unitization" Terms used to denominate the joint operation of all or some portion of a producing reservoir, particularly where there is separate ownership of portions of the rights in a common producing pool, in order to carry on certain production techniques, maximize reservoir production and serve conservation interests economically.

"working interest" The interest in an oil and gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct oil and gas operations on the property and to a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

SIGNATURES

The registrant has duly caused this report to be signed on its behalf by the undersigned, hereunto duly authorized.

April 16, 2003

MARINER ENERGY, INC.

by: /s/ Scott D. Josey

Scott D. Josey,
Chairman of the Board & Chief Executive Officer

This report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

SIGNATURE	TITLE	D
/s/ Scott D. Josey Scott D. Josey	Chairman of the Board	April
/s/ Judd Hansen Judd Hansen	Vice President	April
/s/ David S. Huber David S. Huber	Sr. Vice President	April
/s/ Cory L. Loegering Cory L. Loegering	Vice President - Deepwater Operations	April
/s/ Dalton F. Polasek Dalton F. Polasek	Sr. Vice President	April
/s/ Mike C. van den Bold Mike C. van den Bold	Vice President - Development	April
/s/ Michael A. Wichterich Michael A. Wichterich	Vice President - Finance & Administration	April
/s/ Raymond M. Bowen, Jr. Raymond M. Bowen, Jr.	Director	April
/s/ Craig A. Fox Craig A. Fox	Director	April
/s/ Michael S. McConnell Michael S. McConnell	Director	April
/s/ Jesus G. Melendrez Jesus G. Melendrez	Director	April

/s/ Greg F. Piper	Director	April
Greg F. Piper		

SUPPLEMENTAL INFORMATION TO BE FURNISHED WITH REPORTS FILED PURSUANT TO SECTION 15(d) OF THE ACT BY REGISTRANTS WHICH HAVE NOT REGISTERED SECURITIES PURSUANT TO SECTION 12 OF THE ACT

No annual report covering the Registrant's last fiscal year or proxy statement, form of proxy or other proxy soliciting material with respect to any annual or other meeting of security holders has been sent to the Company's security holders.

CERTIFICATION OF
CHAIRMAN OF THE BOARD / CEO

I, Scott D. Josey, certify that:

1. I have reviewed this annual report on Form 10-K of Mariner Energy, Inc.;

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

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

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

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

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

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

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

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

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

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

Date: April 15, 2003

/s/ Scott D. Josey

Scott D. Josey
Chairman of the Board / CEO

CERTIFICATION OF
VICE PRESIDENT - FINANCE & ADMINISTRATION

I, Michael A. Wichterich, certify that:

1. I have reviewed this annual report on Form 10-K of Mariner Energy, Inc.;

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

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

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

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

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

Date: April 15, 2003

/s/ Michael A. Wichterich

Michael A. Wichterich
Vice President - Finance & Administration

EXHIBIT INDEX

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10.23**	Retention Agreement between Mariner Energy Inc. and Mike Wichterich dated September 27, 2003.
10.28(g)	First Amendment to Amended and Restated Credit Agreement, dated December 31, 1999 by and among Mariner Energy, Inc., Bank of America, N.A., Toronto Dominion (Texas), Inc., Bank of Nova Scotia, and ABN-AMRO Bank, N.V.
10.29(g)[]	Second Amendment to Amended and Restated Consulting Services Agreement, effective as of January 1, 2000, between Mariner Energy, Inc. and David S. Huber.
10.30(g)[]	Third Amendment to Amended and Restated Consulting Services Agreement, effective as of March 4, 2002, between Mariner Energy, Inc. and David S. Huber.
10.31**	Retention Agreement between Mariner Energy Inc. and Mike van den Bold dated September 27, 2003.
10.32**	Retention Agreement between Mariner Energy Inc. and Cory Loegering dated September 27, 2003.
10.39(g)	Corporate Services Agreement, dated August 23, 2001, between the Mariner Energy, Inc. and Enron North America Corp.
23.1**	Consent of Ryder Scott Company.
23.2**	Ryder Scott Company Letter of Estimated Proved Reserves dated March 6, 2002.
99.1	Certificate of Chairman of Board and Chief Executive Officer
99.2	Certificate of Vice President of Finance and Administration

(a) Incorporated by reference to the Company's Registration Statement on Form S-4 (Registration No. 333-12707), filed September 25, 1996.

(b) Incorporated by reference to Amendment No. 1 to the Company's Registration Statement on Form S-4 (Registration No. 333-12707), filed December 6, 1996.

(c) Incorporated by reference to Amendment No. 2 to the Company's Registration Statement on Form S-4 (Registration No. 333-12707), filed December 19, 1996.

(d) Incorporated by reference to the Company's Annual Report on Form 10-K for the year ended December 31, 1996 (Registration No. 333-12707) filed March 31, 1997.

(e) Incorporated by reference to the Mariner Energy LLC November 4, 1999 filing on Forms S-1 (Registration No. 333-87287).

(f) Incorporated by reference to the Mariner Energy, Inc. March 31, 2001, June 30, 2001 or September 30, 2001 quarterly filings on Form 10-Q.

(g) Incorporated by reference to the Mariner Energy Inc. December 31, 2001 annual filing on form 10-K.

(h) Incorporated by reference to the Mariner Energy, Inc. March 31, 2002, June 30, 2002 or September 30, 2002 quarterly filings on Form 10-Q.