MARINER ENERGY INC
Form 10-K
April 03, 2001

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

Form 10-K

For the fiscal year ended December 31, 2000

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 Identification Number)	(I.R.S. Employer organization)

580 WestLake Park Blvd., Suite 1300
Houston, Texas 77079
(Address of principal executive offices including Zip Code)

(281) 584-5500
(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]

The aggregate market value of the voting stock held by non-affiliates of registrant is indeterminable, as there is no established public trading market for the registrant's common stock.

As of March 25 2001, there were 1,380 shares of the registrant's common stock outstanding.

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TABLE OF CONTENTS

PART I

In addition to historical information, this Annual Report on Form 10-K contains statements regarding future financial performance and results and other statements which are not historical facts. These constitute forward-looking statements which are subject to risks and uncertainties that could cause the

Company's actual results to differ materially. Such risks include, but are not limited to, oil and gas price volatility, results of future drilling, availability of drilling rigs, availability of capital resources for drilling and completion activities, future production and costs and other factors. Some of the more important factors that could cause or contribute to such differences include those discussed in Items 1 and 2 "Business and Properties" and Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this report.

Items 1. and 2. Business and Properties

Certain technical terms used in these Items are described or defined in the Glossary presented on page 56 of this report.

(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. Our increasing focus on Gulf water depths greater than 600 feet, or the deepwater, since the early 1990s has made us one of the most experienced independent operators in the deepwater Gulf. 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." Members of our senior management team, most of whom have worked together for over 15 years, and an affiliate of Enron North America Corp. led a buyout of Mariner from Hardy Oil & Gas, plc in April 1996.

Since beginning deepwater operations in 1994, we have:

- operated nine successful field development projects in water depths of 400 feet to 5,600 feet;

- developed three deepwater exploitation projects acquired from major oil companies, including our Pluto project, with a fourth deepwater exploitation project, King Kong, which was acquired from Shell Oil Company in 2000 in progress;

- discovered eight new fields in 16 deepwater Gulf exploration tests;

- acquired 67 deepwater Gulf lease blocks, most of which qualify for relief of royalty payment obligations; and

- built an inventory of 14 exploration prospects as of December 31, 2000, including 13 prospects in the deepwater Gulf.

Ryder Scott Company estimated that we had proved reserves of 203.6 Bcfe as of December 31, 2000, the highest level in our history, of which 63% were natural gas and 37% were oil and condensate. Proved reserves included net reserve additions of 63.6 Bcfe, representing 175% of 2000's company record production of 36.3 Bcfe. Year 2000 additions included first proved reserve bookings from the Aconcagua and Devils Tower discoveries and proved reserves associated with the Company's acquired interest in the King Kong exploitation project.

We expect our production for 2001 to be level or slightly higher than 2000's average rate of 99 MMcfe per day, with production from the Black Widow project expected to offset anticipated production declines in the Company's other fields. With first production from the Mariner-operated King Kong Deepwater Gulf project scheduled for late fourth quarter 2001, our year-end 2001 production rate is expected to rise sharply compared to the production rate of 109 MMcfe per day at the end of 2000. In 2001, we expect to drill seven to ten exploratory wells in the deepwater Gulf, with partners paying Mariner's share of the cost for at least one of the wells. We also plan to increase our 3-D seismic database and leasehold position in the deepwater Gulf. Development activities in 2001 include the completion of our King Kong deepwater Gulf exploitation project, development of the Aconcagua discovery and several development wells in currently-producing fields.

3

We anticipate capital expenditures for 2001, net of proceeds from property conveyances, to be approximately $140 million for leasehold acquisition, exploration drilling and development projects, compared to our 2000 capital expenditures of approximately $79.1 million, net of proceeds from property conveyances of $29.0 million. We expect to fund our capital expenditures by a combination of internally generated cash flow, proceeds from property conveyances, including the recently-announced sale of our remaining interest in the Devils Tower development project, and borrowings against our Revolving Credit Facility.

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, 2000. 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. Year-end oil and gas prices 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 ended December 31, (dollars in millions unless otherwise indicated)	
	2000	1999
Proved reserves:		
Oil (MMbbls)	12.4	9.9
Natural gas (Bcf)	129.3	118.8
Natural gas equivalent (Bcfe)	203.6	178.4
Present value of estimated future net revenues (1)	$ 1,043.2	$ 211.2
Annual reserve replacement ratio (2)	1.7	1.3
Capital expenditures and disposal data:		
Capital costs incurred	$ 108.1	$ 81.5
Proceeds from property conveyances	($ 29.0)	($ 19.8)
Capital costs net of proceeds from property conveyances	$ 78.5	$ 61.7
Percentage of net capital costs attributable to:		
Lease acquisition	10.5%	12.8%
Exploratory drilling, geological and geophysical	19.6%	16.6%
Development and other	69.9%	70.6%
Production:		
Oil (MMbls)	1.8	0.6

Natural gas (Bcf)	25.7	21.1
Natural gas equivalents (Bcfe)	36.3	24.9
Average realized sales price per unit (excluding the effects of hedging):		
Oil ($/Bbl)	$ 29.53	$ 17.53
Natural gas ($/Mcf)	4.07	2.48
Gas equivalent ($/Mcfe)	4.32	2.58
Average realized sales price per unit (including the effects of hedging):		
Oil ($/Bbl)	$ 21.54	$ 14.11
Natural gas ($/Mcf)	3.24	2.16
Gas equivalent ($/Mcfe)	3.34	2.19
Expenses ($/Mcfe):		
Lease operating	0.47	0.46
Transportation	0.22	0.08
General and administrative, net	0.18	0.22

(1) Discounted at an annual rate of 10%. See "Glossary" included elsewhere in this 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 an Mcfe basis for the year by actual production on an Mcfe basis for such year.

(3) In an acquisition effective April 1, 1996 for accounting purposes, Mariner Holdings, Inc. acquired all the capital stock of the Company from Hardy Holdings Inc. as part of a management-led buyout. In connection with the acquisition, substantial intercompany indebtedness and receivables and third-party indebtedness of the Company were eliminated. The acquisition was accounted for using the purchase method of accounting, and Mariner Holdings' cost of acquiring the Company was allocated to the assets and liabilities of the Company based on estimated fair values. As a result, the Company's financial position and operating results subsequent to the acquisition reflect a new basis of accounting and are not comparable to prior periods. "Predecessor Company" refers to Mariner Energy, Inc. (formerly named "Hardy Oil & Gas USA Inc.") prior to the effective date of the acquisition.

(b) Competitive Strengths and Business Strategy

Competitive Strengths

We have several competitive strengths that we believe will allow us to compete successfully in oil and natural gas exploration, production and development activities in the Gulf:

Early Entry Into the Deepwater Gulf. We began focusing in the deepwater Gulf in 1994 as one of the first independent oil and natural gas companies to recognize the opportunity for acquiring smaller deepwater discoveries not meeting a large company's field size threshold and for partnering with major oil companies to develop these discoveries. We believe our six years in the deepwater Gulf have provided us with the geophysical and geological skills, operating expertise and relationships necessary to operate successfully in the deepwater. Our deepwater Gulf expertise includes:

- a strong understanding of the geology and geophysics of the deepwater Gulf;

- familiarity with challenges peculiar to operating in the deepwater Gulf; and

- relationships with vendors, major oil companies and other partners having complementary skills and knowledge of the area.

Substantial Acreage, Seismic Data and Prospect Inventory. Our Gulf leasehold inventory as of December 31, 2000, consisted of 100 lease blocks, including 67 in the deepwater. Our prospect inventory includes 15 exploration prospects, 14 of which are in the deepwater Gulf. We expect to drill seven to ten of our deepwater exploration prospects by the end of 2001. Our seismic database includes 3-D seismic that covers approximately 8,200 square miles of the Gulf and modern 2-D seismic that covers more than 250,000 miles of the deepwater Gulf. We internally generate substantially all of our exploration and exploitation prospects using 3-D seismic data.

Experienced Operations and Technical Staff and Management. Our 13 geoscientists average more than 20 years of experience in the exploration and production business, including extensive experience in the deepwater Gulf and with major oil companies. Our 6 deepwater operations managers average over 25 years of experience with major oil companies and large independents around the world. Most of our senior management team participated in our acquisition from Hardy and have worked together for over 15 years. Management and other key personnel currently own approximately 4% of the common shares of our parent company and have options that, if exercised, would increase their ownership to 17%. We believe that management's ownership aligns its interests with those of other shareholders.

Strategy

Our business strategy is to increase reserves, production and cash flow by emphasizing growth through the drillbit in the deepwater Gulf; the use of subsea technology to develop mid-sized fields that are either acquired from major oil companies or discovered via low-cost exploration. Our strategy consists of the following elements:

- Focus on the Deepwater Gulf. Our early entry into the deepwater Gulf in 1994 has allowed us to develop the geophysical and geological skills, operating expertise and relationships with partners necessary to operate successfully in the deepwater. With our current prospect and seismic inventory and many more deepwater Gulf lease blocks expected to become available via lease sales and farmouts from existing leaseholders, we believe we are well-positioned to increase our deepwater Gulf activity and to continue to generate and exploit economically attractive prospects.

- Pursue a Balanced Portfolio Approach to our Drilling Program. We target six to ten new prospects each year, with a strong deepwater Gulf emphasis. The program is designed to provide reserve replacement and production growth through low-risk deepwater exploitation projects and opportunities for substantial growth through moderate-risk exploration prospects that can significantly increase our reserve base.

- 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. Almost all of our inventory of exploration prospects were internally generated by our staff of geoscientists, which has extensive experience in the deepwater Gulf. Through our technical staff's understanding of the geology and geophysics of the deepwater Gulf and our inventory of leasehold blocks and seismic data, we intend to continue to generate the majority of our prospects internally.

- Manage Deepwater Risks. We intend to reduce our deepwater risks by continuing to:

  - target prospects with relatively low gross drilling costs ranging from $5 million to $20 million;

  - use 3-D seismic technology to identify direct hydrocarbon indicators and to lessen the risk of dry holes; and

  - limit the financial exposure of our deepwater prospect portfolio by:

  - selling a portion of our working interests in our deepwater projects to industry partners, typically on a promoted basis where all or a portion of our exploratory costs are paid by partners;

  - generally maintaining a 25% to 50% interest during the appraisal phase of a successful exploratory project; and

  - reducing our interest in the development phase of a project when appropriate, considering other opportunities in our investment portfolio, the need to avoid becoming overly concentrated in a few projects and the availability of capital.

- Apply Our Deepwater Operational Expertise. Our deepwater operations managers average over 25 years of experience with major oil companies and large independents around the world. By operating most of our deepwater projects, we intend to apply the experience of our staff to continue to:

  - maintain efficient drilling performance;

  - shorten project cycle times;

  - reduce operational risks and life of project finding and development costs; and

  - innovatively use proven subsea production technology and develop low cost, mobile floating production facilities.

(c) Reserves

The following table sets forth certain information with respect to our proved reserves by geographic area as of December 31, 2000. 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, 2000 is based upon a reserve report prepared by the independent petroleum consulting firm of Ryder Scott Company. 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 9 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, 2000					
	Proved Reserve Quantities			Present Value of Estimated Future Net Revenues (1) Dollars in millions		
Geographic Area	Oil (MMBbls)	Natural Gas (Bcf)	Total (Bcfe)	Developed	Undeveloped	
Deepwater Gulf	7.7	87.5	133.7	$ 391.5	$ 371.7	$ 7
Gulf Shallow Water and Gulf Coast Onshore	0.3	18.5	20.2	138.1	11.8	1
Permian Basin	4.4	23.3	49.7	62.5	67.6	1
Total	12.4	129.3	203.6	592.1	451.1	1,0
Proved Developed Reserves	5.5	61.6	94.6	$ 592.1		

(1) Discounted (at 10%) present value as of December 31, 2000 (year-end prices held constant excluding hedging activities).

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

(d) Oil and Gas Properties

(i) Significant Properties with Proved Reserves as of December 31, 2000

We own oil and gas properties, both producing and for future exploration and development, onshore in Texas and offshore in the Gulf, primarily in federal waters. Our nine largest producing properties, as shown in the following table, accounted for approximately 93% of the Company's proved reserves as of December 31, 2000.

	Operator	Mariner Working Interest	Approximate Water Depth (Feet)	Producing Wells	
Deepwater Gulf:					
Mississippi Canyon 773 (Devils Tower (1)	Dominion	20%	5,600	--	Firs
Green Canyon 472 (King Kong)............	Mariner	50%	3,900	--	Four
Mississippi Canyon 718 (Pluto)..........	Mariner	51%	2,710	1	D
Mississippi Canyon 305 (Aconcagua)......	Elf	25%	7,100	--	Four
Ewing Bank 966 (Black Widow)............	Mariner	69%	1,850	1	O
Garden Banks 73 (Apia)..................	Mariner	100%	700	1	
Garden Banks 367 (Dulcimer).............	Mariner	41.7%	1,100	1	
Gulf Shallow Water and Gulf Coast Onshore:					
Brazos A-105..........................	Spirit Energy	12.5%	192	5	J
Permian Basin of West Texas:					
Spraberry Aldwell Unit(2)..............	Mariner	70.3%	Onshore	82	
Other Properties.......................	--	--	--	--	

Total Proved Reserves...................

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(1) Our working interest in Devils Tower was sold to a subsidiary of Dominion in March 2001.

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

Following is additional informati on regarding the properties in the table shown above.

7

Principal Oil and Natural Gas Properties

Deepwater Gulf of Mexico

Mississippi Canyon 773 (D evils Tower). We generated the Devils Tower prospect and acquired it in the Ma rch 1998 federal lease sale. The prospect is located approximately 140 miles so utheast of New Orleans in 5,600 feet of water. During the fourth quarter of 1999, we drilled a successful exploration well on the prospect, encountering multiple hydrocarbon bearing zones. Casing was run in the well and the well was temporarily suspended. Our share of the drilling cost for the exploration well was paid by our partners in the prospect. In May 2000, we sold a 30% working interest in the project to one of our partners, Dominion Exploration & Production, Inc., who subsequently became the operator, and we retained a 20% working interest. During the second quarter of 2000, a successful appraisal well was drilled, followed immediately by a successful sidetrack of the appraisal well. Development activities are in progress, with first production anticipated for early 2003. In the first quarter of 2001, we sold our remaining 20% working interest to Dominion Exploration & Production, Inc. to better manage financial and operational risk, to obtain an acceptable return without holding the investment through depletion and to re-deploy capital to other projects in our deepwater Gulf niche.

Green Canyon 472 (King Kong) In July 2000,we entered into an agreement to acquire Shell Exploration and Production Company's 50% working interest in the "King Kong" Deepwater Gulf of Mexico development project. The project is located in approximately 3,900 feet of water in Green Canyon Blocks 472, 473 and 517, 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. We intend to develop gas reserves from two separate reservoirs discovered by three exploration wells that were previously drilled in the project. The initial development plan calls for completing a previously-drilled well and drilling an additional development well, with both subsea wells tied back 16 miles to the Allegheny mini-TLP operated by Agip. We also plan to drill our "Yosemite" exploration prospect located adjacent to King Kong in Green Canyon Block during 2001. If successful, we expect Yosemite to be jointly developed with King Kong. We anticipate production from the project to commence by late 2001. The King Kong development project is located in the same area of Green Canyon where we have assembled several other exploration prospects, including Yosemite, providing us with the opportunity to capitalize on synergies for the development of any discoveries. The field had estimated net proved reserves of 25.5 Bcfe as of December 31, 2000.

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. 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 deepwater Gulf approximately 150 miles southeast of New Orleans, Louisiana at a water depth of 2,700 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, 2000 the field produced 11.5 Bcfe net to us. As of December 31, 2000, the field had estimated net proved reserves of 21.5 Bcfe, 75% of which was natural gas.

Mississippi Canyon 305 (Aconcagua). We generated the Aconcagua prospect and acquired it at a federal offshore Gulf lease sale in March 1998. We hold a 25% working interest in the block. During the first quarter of 1999, the operator, Elf Exploration Inc., drilled a successful exploration well on the prospect, on which our share of the drilling cost was paid by one of our partners. The well logged multiple pay sands, which are geological formations where deposits of oil or gas are found in commercial quantities, and we encountered additional sands with productive potential. The well is located 40 miles from the shelf edge in 7,100 feet of water approximately 150 miles southeast of New Orleans. Elf Exploration Inc. drilled a successful appraisal well in March 2000, encountering over 250 net feet of gas pay and confirming that reservoirs found in the discovery well extend approximately two miles to the northeast. Aconcagua is included in the Canyon Express joint subsea development project, which will gather production from three deepwater natural gas fields and transport it over 47 miles to a new platform to be built by Williams Field Services - Gulf Coast Company, L.P., at a location in shallow water on the outercontinental shelf. We anticipate that production will commence in the fourth quarter of 2002. The field had estimated net proved reserves of 19.2 Bcfe at December 31, 2000.

Ewing Bank 966 (Black Widow). We generated the Black Widow prospect and acquired it 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 deepwater 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, 2000 2.1 Bcfe net to us. Estimated net proved reserves from Black Widow were approximately 18.9 Bcfe, 85% of which was oil, as of December 31, 2000.

Garden Banks 73 (Apia). We generated the Apia prospect and acquired it in a federal offshore lease sale in August 1998. We operate and own a 100% working interest in this project which is located offshore Louisiana in a water depth of approximately 700 feet. In September 1999 we drilled a successful exploration well which encountered 102 net feet gas pay in a single zone. The field was developed by the single subsea well tied back to a host platform approximately three miles from the well. Production began on April 29, 2000 and through

December 31, 2000 it has produced 5.9 Bcfe net to us. The field had estimated net proved reserves of 11.6 Bcfe, all of which was natural gas, as of December 31, 2000.

Garden Banks 367 (Dulcimer). We generated the Dulcimer prospect and acquired it at a federal offshore Gulf lease sale in September 1996. The well is located in the deepwater Gulf approximately 170 miles south of Lake Charles, Louisiana at a water depth of approximately 1,100 feet. We operate and have a 42% working interest in the property. In late 1997, we drilled a successful exploration well in two productive intervals between 9,900 feet and 10,500 feet. The well commenced production in April 1999, after tieback to a production platform located approximately 14 miles from the well. In May 2000, Dulcimer began to produce lower gas rates in conjunction with the onset of reservoir-related water production. To improve performance we drilled for additional reserves in the existing well bore as well as sidetracking the well to an updip location in this fault block in February 2001. Through December 31, 2000, the field had produced 7.5 Bcfe net to us. The field had estimated net proved reserves of 5.4 Bcfe, all of which was natural gas, as of December 31, 2000.

Gulf Shallow Water and Gulf Coast Onshore

Brazos A-105. We generated the Brazos A-105 prospect and own a 12.5% working interest in this Spirit Energy-operated property, which commenced production in January 1993. Five wells exploit a single reservoir. No additional wells are currently anticipated. The field has produced 25.1 Bcfe net to us from its inception through December 31, 2000. The field had estimated remaining net proved reserves of 8.8 Bcfe as of December 31, 2000, 99% of which was 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, 72 infill wells have been drilled resulting in 71 productive wells. Currently there are a total of 82 producing wells in the unit. Depending on, among other things, the future prices of oil and natural gas, we may drill 20 to 40 additional infill wells, bringing proved undeveloped reserves into production, in the next two to four years at a projected cost of approximately $340,000 to $400,000 per well. We estimate that the field's remaining net proved reserves as of December 31, 2000 was 49.7 Bcfe. We believe that the field's potential for continued economic oil production exceeds 40 years.

9

(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 therefrom to activities that we believe have a higher potential financial return. No property dispositions of producing properties were made during 2000. In 2000 and 2001, we sold interests in a discovered field for which production had not yet commenced.

(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.

(e) 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 ended December 31,		
	2000	1999	1998
Production:			
Oil (MMbbls)	1.8	0.6	0.8
Natural gas (Bcf)	25.7	21.1	19.5
Gas equivalent (Bcfe)	36.3	24.9	24.2
Average sales prices excluding effects of hedging:			
Oil ($/Bbl)	$ 29.53	$ 17.53	$ 12.99
Natural gas ($/Mcf)	4.07	2.48	2.33
Gas equivalent ($/Mcfe)	4.32	2.58	2.30
Average sales prices including effects of hedging:			
Oil ($/Bbl)	$ 21.54	$ 14.11	$ 12.99
Natural gas ($/Mcf)	3.24	2.16	2.45
Gas equivalent ($/Mcfe)	3.34	2.19	2.40
Expenses ($/Mcfe):			
Lease operating	0.47	0.46	0.41
Transportation	0.22	0.08	0.05
General and administrative, net (1)	0.18	0.22	0.20
Depreciation, depletion and amortization (2)	1.57	1.29	1.40
Cash margin ($/Mcfe) (3)	2.26	1.18	1.47

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

(2) Excludes impairment of oil & gas properties of $50.8 million for the year ended December 31, 1998. No impairment was necessary for either of the years ended December 31, 1999 and 2000.

(3) Average equivalent gas sales price (including the effects of hedging),

minus lease operating and gross general and administrative expenses.

(f) 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, 2000:

	Total Productive Wells	
	Gross	Net
Oil	87	53.2
Gas	52	9.7
Total	139	62.9

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.

(g) Acreage

The following table sets forth certain information with respect to the developed and undeveloped acreage as of December 31, 2000.

	Developed Acres (1)		Undeveloped Acres (2)	
	Gross	Net	Gross	Net
Texas (Onshore)	19,067	12,604	747	440
All other states (Onshore)	671	212	574	126
Offshore	229,289	64,987	280,940	149,642
Total	249,027	77,803	282,261	150,208

(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.

(h) Drilling Activity

Certain information with regard to our drilling activity during the years ended December 31, 2000, 1999 and 1998 is set forth below.

	Year Ended December 31,					
	2000		1999		1998	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						

Producing................	1	0.40	3	1.75	3	1.10
Dry......................	3	2.08	2	0.50	5	1.54
Total................	4	2.48	5	2.25	8	2.64
Development wells:						
Producing................	2	0.45	8	1.61	19	8.61
Dry......................	-	-	-	-	3	1.13
Total................	2	0.45	8	1.61	22	9.74
Total wells:						
Producing................	3	0.85	11	3.36	22	9.71
Dry......................	3	2.08	2	0.50	8	2.67
Total................	6	2.93	13	3.86	30	12.38

(i) Marketing, Customers and Hedging Activities

We market substantially all oil and gas production from properties we operate and from properties operated by others where our interest is significant. The majority 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 as to the sale of such gas and the processing thereof which we believe to be competitive. Similarly, we have a gas processing agreement on our gas production from Sandy Lake which we believe has the effect of pricing our gas production favorably compared to market prices at that location. The following table lists customers accounting for more than 10% of our total revenues for the year indicated (a "-" indicates that revenues from the customer accounted for less than 10% of our total revenues for that year).

	Percentage of total revenues For the year ended December 31,		
Customer	2000	1999	1998
Enron North America and affiliates (An affiliate of the Company)	49%	26%	15%
Transco Energy Marketing Company	--	21%	16%
Duke Energy	16%	13%	29%
Genesis Crude Oil LP	--	--	10%

Due to the nature of the markets for oil and natural gas, we do not believe that the loss of any one of these customers would have a material adverse effect on our financial condition or results of operations.

We have utilized hedging transactions with respect to a portion of our oil and gas production to reduce our exposure to price fluctuations and to achieve a more predictable cash flow. We do not engage in hedging activities for speculative purposes. We customarily conduct our hedging strategy through the use of swap arrangements that establish an index-related price above which we pay the hedging partner and below which we are paid by the hedging partner. During 2000, approximately 71% of our equivalent production was subject to hedge positions.

The following table sets forth our open hedge positions as of December 31, 2000.

Time Period	Notional Quantities	Price Floor	Price Ceiling	Price Fixed	Fair Value (in millions)
Natural Gas (MMBtu)					
January 1 - September 30, 2001					
Collar purchased	4,216	$3.50	$4.92		(8.5)
Put option purchased	4,216	$3.50			--
Fixed price swap purchased	3,376			$2.18	(18.0)
October 1 - December 31, 2001					
Fixed price swap purcahsed	774			2.18	(2.5)
January 1 - December 31, 2002					
Fixed price swap purchased	1,831			2.18	(4.3)
Total					($33.3)

Hedging arrangements for 2001 and 2002 cover approximately 36% and 4% of our anticipated equivalent production, respectively. Hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances where our production, which is in effect hedged, is less than expected or where there is a sudden, unexpected event materially impacting prices. Our Revolving Credit Facility (see Note 3 of the financial statements) places certain restrictions on our use of hedging. See "Management's Discussion and Analysis of Financial Condition and Results of Operations--Changes in Prices and Hedging Activities".

(j) 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.

(k) 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 State 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. We have acquired 50 new deepwater leases that are qualified for royalty relief and have received royalty relief on the four lease blocks comprising the Pluto project. However, in the event that prices exceed certain prescribed thresholds royalty relief is suspended. In 2000 natural gas prices exceeded these thresholds and we are required to pay royalties on the Pluto project for the year.

(l) Regulation

Our operations are subject to extensive and continually changing regulation because legislation affecting the oil and natural gas industry is under constant review for amendment and expansion. 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. However, we do not believe that it is affected in a significantly different manner by these regulations than are our competitors in the oil and natural gas industry.

(i) Transportation and Sale of Natural Gas

The FERC 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 to limit 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 plans and our 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 are 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 principle 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.

(m) Employees

As of December 31, 2000, we had 81 full-time employees. Our employees are not represented by any labor union. We consider relations with our employees to be satisfactory. We have never experienced a work stoppage or strike.

Item 3. Legal Proceedings

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.

Item 4. Submission of Matters to a Vote of Security Holders

None.

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.

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)

Statement of Operations Data:	Year Ended December 31, 2000	1999	1998	1997	Nine Months Ended 12/31/96	Predec Comp (1 Thre Mont Ende 03/31
Total revenues	$ 121.1	$ 54.5	$ 58.0	$ 64.1	$ 48.4	$ 1
Lease operating expenses	17.2	11.5	9.9	9.4	6.5	
Transportation	7.8	2.0	1.3	1.3	1.3	
Depreciation, depletion and amortization	56.8	32.1	33.8	31.7	24.8	
Impairment of oil and gas properties	--	--	50.8	28.5	22.5	
Provision for litigation	--	--	2.8	--	--	
General and administrative expenses	6.5	5.4	4.8	3.2	2.4	
Operating income (loss)	32.8	3.5	(45.4)	(10.0)	(9.1)	
Interest income	0.1	--	0.3	0.5	0.5	
Interest expense	(11.0)	(13.5)	(13.3)	(10.6)	(7.7)	(
Write-off of bridge loan fees	--	--	--	--	(2.4)	
Income (loss) before income taxes	21.9	(10.0)	(58.4)	(20.2)	(18.7)	
Provision for income taxes	-	-	-	-	-	
Net income (loss)	$21.9	($10.0)	($58.4)	($20.2)	($18.7)	$
Capital Expenditure and Disposal Data:						
Exploration, incl. leasehold/seismic	$ 46.7	$ 24.0	$ 78.8	$ 49.0	$ 31.9	$
Development and other	61.4	57.5	63.1	19.9	7.0	
Proceeds from property conveyances	(29.0)	(19.8)	--	--	(7.5)	
Total capital expenditures net of proceeds from property conveyances	$ 79.1	$ 61.7	$141.9	$ 68.9	$ 31.4	$

Balance Sheet Data (at end of period):

Oil and gas properties, net, at full cost	$287.8	$263.6	$233.3	$175.7	$166.6	$12
Long-term receivable from affiliates	--	--	--	--	--	10
Total assets	335.4	297.5	262.3	212.6	196.8	25
Long-term debt, less current maturities .	129.7	167.3	124.6	113.6	99.5	16
Stockholder's equity	141.9	65.0	27.5	57.2	77.1	7

(1) - In an acquisition effective April 1, 1996 for accounting purposes, Mariner Holdings, Inc. acquired all the capital stock of the company from Hardy Holdings Inc. as part of a management-led buyout. In connection with the acquisition, substantial intercompany indebtedness and receivables and third-party indebtedness of the Company were eliminated. The acquisition was accounted for using the purchase method of accounting, and Mariner Holdings' cost of acquiring the Company was allocated to the assets and liabilities of the Company based on estimated fair values. As a result, the Company's financial position and operating results subsequent to the acquisition reflect a new basis of accounting and are not comparable to prior periods. "Predecessor Company" refers to Mariner Energy, Inc. (formerly named "Hardy Oil & Gas USA Inc.") prior to the effective date of the acquisition.

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, 1998 and ended December 31, 2000. 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, it 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 and along the U.S. Gulf Coast. Our strategy is to profitably increase reserves, production and cash flow primarily through the drillbit with a heavy emphasis on the deepwater Gulf.

During 2000 we:

- drilled four exploratory wells, with one success, in the deepwater Gulf of Mexico, making us eight of sixteen in deepwater Gulf exploratory test wells drilled since the acquisition from Hardy;

- drilled successful appraisal wells on our Aconcagua and Devils Tower prospects;

- commenced production from two significant deepwater projects; Apia in April 2000 and Black Widow in October 2000, which, when combined with first production from Pluto in late 1999, resulted in the highest level of production in our history;

- o acquired from Shell Oil Company a 50% interest in the King Kong deepwater Gulf exploitation project;

- o sold a portion of our Devils Tower discovery to one of our partners in the project, reducing our working interest from 50% to 20%, the remainder of which was sold to the same partner in the first quarter of 2001 to better manage financial and operational risk;

- o added proved reserves of 63.6 Bcfe, which were approximately 175% of our 2000 production of 36.3 Bcfe, including first proved reserve bookings from the Aconcagua and Devils Tower discoveries and from the King Kong exploitation project, resulting in the highest level of proved reserves in our history;

- o completed the settlement of a drilling rig commitment dispute, securing access to a rig capable of drilling many of the prospects in our deepwater Gulf inventory.

We expect capital expenditures for 2001, net of proceeds from property conveyances, to be approximately $140 million, which we intend to use to explore, develop and continue to build our prospect inventory. We expect to fund our capital expenditures by a combination of internally generated cash flow, proceeds from property conveyances and borrowings against our Revolving Credit Facility.

Our revenue, profitability, access to capital and future rate of growth are heavily influenced by the price we receive for our production. The markets for oil, natural gas and natural gas liquids have been historically volatile and may continue to be volatile in the future. We enter into hedging transactions for our oil and natural gas production and intend to continue doing so. These transactions may limit our potential gains if oil and natural gas prices were to rise substantially over the price established by the hedges. These hedges also may expose us to the risk of financial loss in some instances, including possible production shortfalls and unexpected price changes.

Competition, both from other sources of energy such as electricity and from within the industry, also affects our performance. Many of our larger competitors possess and employ financial and personnel resources substantially greater than those available to us, which can be particularly important in deepwater Gulf activities. These companies may be able to pay more than we can 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.

18

We use the full cost method of accounting for our investments in oil and natural gas properties. Under this methodology, all costs of exploration, development and acquisition of oil and natural gas reserves are capitalized into a "full cost pool" as incurred and properties in the pool are depleted and charged to operations using the unit-of-production method based on a ratio of current production to total proved oil and natural gas reserves. To the extent that capitalized costs less deferred applicable taxes exceed the present value, using a 10% discount rate, of estimated future net cash flows from proved oil and natural gas reserves and the lower of cost or fair market value of unproved properties, the excess costs are charged to operations. Capitalized costs are net of accumulated depreciation, depletion and amortization. If a writedown were required, it would result in a charge to earnings but would not have an impact on cash flows.

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) 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 ended December 31,		
	2000	1999	1998
Production:			
Oil (MMbbls)	1.8	0.6	0.8
Natural gas (Bcf)	25.7	21.1	19.5
Gas equivalent (Bcfe)	36.3	24.9	24.2
Average sales prices excluding effects of hedging:			
Oil ($/Bbl)	$ 29.53	$ 17.53	$ 12.99
Natural gas ($/Mcf)	4.07	2.48	2.33
Gas equivalent ($/Mcfe)	4.32	2.58	2.30
Average sales prices including effects of hedging:			
Oil ($/Bbl)	$ 21.54	$ 14.11	$ 12.99
Natural gas ($/Mcf)	3.24	2.16	2.45
Gas equivalent ($/Mcfe)	3.34	2.19	2.40
Expenses ($/Mcfe):			
Lease operating	0.47	0.46	0.41
Transportation	0.22	0.08	0.05
General and administrative, net	0.18	0.22	0.20
Depreciation, depletion and amortization (excluding impairments)	1.57	1.29	1.40

(i) 2000 compared to 1999

Net production increased during 2000 to 36.3 billion cubic feet of natural gas equivalent (Bcfe) from 24.9 Bcfe in 1999, a 46% improvement. Production from the Pluto, Apia and Black Widow projects, all located in the Deepwater Gulf of Mexico and commissioned during 2000, more than offset production declines in the Company's other fields, primarily the Sandy Lake field, located onshore, and the Dulcimer and Rembrandt fields, located offshore.

Hedging activities in 2000 decreased our average realized natural gas price received by $0.83 per Mcf and revenues by $21.4 million, compared with a decrease of $0.32 per Mcf and revenues of $6.7 million in 1999. Our hedging activities with respect to crude oil during 2000 reduced the average sales price received by $7.97 per Bbl and revenues by $14.1 million compared with a decrease of $3.42 per Bbl and revenues of $2.2 million.

Oil and gas revenues increased 122% to $121.1 million for 2000 from $54.5 million for 1999, due to a 53% increase in realized prices to $3.34 per Mcfe in 2000 from $2.19 per Mcfe in 1999.

Lease operating expenses increased 50% to $17.2 million for 2000 from $11.5 million for 1999 due to the higher offshore production discussed above.

Transportation expenses increased 290% to $7.8 million for 2000 from $2.0 million for 1999. The increase was attributable to the full years transportation expense on Pluto.

Depreciation, depletion, and amortization expense increased 77% to $56.8 million for 2000 from $32.1 million for 1999 as a result of the increase in the unit-of-production depreciation, depletion and amortization rate to $1.57 per Mcfe from $1.29 per Mcfe. This increase was in addition to increased depreciation, depletion and amortization as a result of the increased production mentioned above.

General and administrative expenses, which are net of overhead reimbursements we received from other working interest owners, increased 22% to $6.6 million for 2000 from $5.4 million for 1999 due to increased personnel-related costs in 2000 required for us to pursue our deepwater Gulf exploration and development plan.

Interest expense for 2000 decreased 19% to $11.0 million from $13.5 million for 1999, primarily due to capital contributions by the sale of common stock to our Parent which were used to reduce debt.

Income (loss) before income taxes increased to a net income of $21.9 million for 2000 from a loss of $10.0 million in 1999. Primarily as a result of increased revenue and increased expenses discussed above.

(ii) 1999 compared to 1998

Net production increased 3% to 24.9 Bcfe for 1999 from 24.2 Bcfe for 1998. Production from our offshore Gulf properties increased to 18.2 Bcfe in 1999 from 13.1 Bcfe in 1998, as a result of production commencing from a new well in the Dulcimer field located in Garden Banks block 367 and two new wells in the Rembrandt field located in Galveston block 151. This increase was offset by less than expected production from our Sandy Lake field onshore Texas.

Hedging activities in 1999 decreased our average realized natural gas price received by $0.32 per Mcf and revenues by $6.7 million, compared with an increase of $0.12 per Mcf and revenues of $2.3 million in 1998. Our hedging activities with respect to crude oil during 1999 reduced the average sales price received by $3.42 per Bbl and revenues by $2.2 million. There were no oil hedges in 1998.

Oil and gas revenues decreased 6% to $54.5 million for 1999 from $58.0 million for 1998, due to a 9% decrease in realized prices to $2.19 per Mcfe in 1999 from $2.40 per Mcfe in 1998.

Lease operating expenses increased 16% to $11.5 million for 1999 from $9.9 million for 1998 due to the higher offshore production discussed above and well workovers on three offshore wells and two wells in our Sandy Lake field.

Transportation expenses increased 54% to $2.0 million for 1999 from $1.3 million for 1998. The increase was attributable to the addition of additional production on offshore properties that are subject to transportation tarriffs.

Depreciation, depletion, and amortization expense decreased 5% to $32.1 million for 1999 from $33.8 million for 1998 as a result of the decrease in the unit-of-production depreciation, depletion and amortization rate to $1.29 per

Mcfe from $1.40 per Mcfe. This decrease was offset in part by a 3% increase in equivalent volumes produced. The lower rate for 1999 was primarily due to the $50.8 million non-cash full cost ceiling test impairment recorded in 1998. No impairment was necessary for 1999.

General and administrative expenses, which are net of overhead reimbursements we received from other working interest owners, increased 14% to $5.4 million for 1999 from $4.7 million for 1998 due to increased personnel-related costs in 1999 required for us to pursue our deepwater Gulf exploration and development plan.

Interest expense for 1999 increased 1% to $13.5 million from $13.4 million for 1998.

Income (loss) before income taxes decreased to a loss of $10.0 million for 1999 from a loss of $58.4 million in 1998 as a result of a $50.8 million full cost ceiling test impairment, offset in part by oil and gas revenue decreases and increased expenses discussed above.

(d) Liquidity and Capital Resources

(i) Cash Flows

As of December 31, 2000, we had a working capital deficit of approximately $15.4 million, compared to a working capital deficit of $32.3 million at December 31, 1999. The reduction in the working capital deficit was primarily a result of a $55.0 million cash equity contribution by the sale of common stock to our Parent, which was used to reduce accounts payable, accrued liabilities and affiliate debt as well as provide funds for capital expenditures. We expect our 2001 capital expenditures, excluding capitalized general and administrative, interest costs and proceeds from property conveyances, to be approximately $140 million, which would exceed cash flow from operations. However, we believe there will be adequate cash flow due to increased commodity prices and proceeds from property conveyances in order for us to fund our remaining planned activities in 2001. There can be no assurance that our access to capital will be sufficient to meet our needs for capital. As such, we may be required to reduce our planned capital expenditures and forego planned exploratory drilling.

We had a net cash inflow of $2.3 million in 2000, compared to a net cash inflow of $0.1 million in 1999 and a net cash outflow of $9.1 million in 1998. A discussion of the major components of cash flows for these years follows.

	2000	1999	1998
Cash flows provided by operating activities (in millions).......	$ 63.9	$ 24.4	$ 39.6

Cash flows provided by operating activities in 2000 increased by $39.5 million compared to 1999 due to increased oil and gas prices, production lease operating and general and administrative expenses. Cash flows from operating activities in 1999 decreased by $15.2 million from 1998 primarily due to decreased oil and gas prices.

	2000	1999	1998
Cash flows used in investing activities (in millions)..................	$ 79.1	$ 61.8	$141.9

Cash flows used in investing activities in 2000 increased by $17.3 million compared to 1999 due to increased capital expenditures offset by $29.0 million in proceeds from property conveyances. Cash flows used in investing activities in 1999 decreased by $80.1 million compared to 1998 due to decreased capital expenditures and the receipt of proceeds from property conveyances.

	2000	1999	1998
Cash flows provided by financing activities (in millions)................	$ 17.4	$ 37.5	$ 93.2

Cash flows provided by financing activities in 2000 decreased by $20.1 million compared to 1999 due to a $37.6 million net reduction in borrowings against our Revolving Credit Facility and our Affiliate Credit Facility as compared to a $14.2 million increase in borrowings against that facility for the previous year. In addition, capital contributions by the sale of stock to Parent increased by $31.7 million. Cash flows provided by financing activities in 1999 decreased by $55.7 million as compared to 1998 due to a net reduction in borrowings of $50.2 million from borrowings against our various credit facilities.

(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 through the use of commodity futures, options and swap agreements. While the use of these hedging arrangements limits the downside risk of adverse price movements, it also limits future gains from favorable movements.

The following table sets forth the increase or decrease in our oil and gas sales as a result of hedging transactions and the effects of hedging transactions on prices during the periods indicated.

	Year Ended December 31,		
	2000	1999	1998
Increase (decrease) in natural gas sales (in millions)	$ (21.4)	$ (6.7)	$ 2.
Increase (decrease) in oil sales (in millions)	(14.1)	(2.2)	-
Effect of hedging transactions on average gas sales price (per Mcf)....	(0.83)	(0.32)	0.1
Effect of hedging transactions on average oil sales price (per Bbl)....	(7.97)	(3.42)	-

Hedging arrangements for 2000 covered approximately 71% of our equivalent production for the year. Hedging arrangements for 2001 and 2002 cover approximately 36% and 4% of our anticipated equivalent production, respectively.

The following table sets forth our open hedge positions as of December 31, 2000.

		Price			
Time Period	Notional Quantities	Floor	Ceiling	Fixed	Fair Value

					(in millions)
Natural Gas (MMBtu)					
January 1 - September 30, 2001					
Collar purchased	4,216	$3.50	$4.92		(8.5)
Put option purchased	4,216	$3.50			--
Fixed price swap purchased	3,376			$2.18	(18.0)
October 1 - December 31, 2001					
Fixed price swap purchased	774			2.18	(2.5)
January 1 - December 31, 2002					
Fixed price swap purchased	1,831			2.18	(4.3)
Total					($33.3)

The fair value for our hedging instruments was determined based on brokers' forward price quotes and NYMEX forward price quotes as of December 31, 2000. As of December 31, 2000, a commodity price increase of 10% would have resulted in an unfavorable change in the fair value of our hedging instruments of $6.8 million and a commodity price decrease of 10% would have resulted in a favorable change in the fair value of our hedging instruments of $6.6 million.

Our senior subordinated notes have a fixed rate and, therefore, do not expose us to risk of earnings loss due to changes in market interest rates. However, we are subject to interest rate risk under our Revolving Credit Facility and our short-term credit facility with ENA. For example a 100 basis point increase in the London Interbank Offered Rate would have increased our 2000 interest expense by $0.4 million. The carrying value of our Revolving Credit Facility approximates market since these instruments have floating interest rates. The market value of the senior subordinated notes was approximately $91.0 million based on borrowing rates available at December 31, 2000.

(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, 2000.

	Year Ended December 31,		
	2000	1999	1998
Capital expenditures (in millions):			
Leasehold acquisition-- unproved properties...	$ 1.7	$ 3.0	$ 43.1
Leasehold acquisition-- proved properties.....	-	-	-
Oil and natural gas exploration..............	16.0	13.5	35.7
Oil and natural gas development and other.....	61.4	45.2	63.1
Total capital expenditures, net of proceeds from property conveyances.........................	$79.1	$61.7	$ 141.9

Our capital expenditures for 2000 were $79.1 million, excluding the $29.0 million of proceeds from property conveyances, which was $17.4 million more than 1999. The increase was primarily a result of higher leasehold acquisition, geological and geophysical, exploratory drilling and development costs as we operated with increased access to capital. Before property conveyances, our 2000 capital expenditures included $32.3 million for exploration activities, $63.6 million for development activities and $11.7 million of capitalized indirect costs.

Our total capital expenditures for 1999 were $61.7 million, excluding $19.8 million in proceeds from property conveyances, which was $80.2 million less than 1998. The decrease was due primarily to lower leasehold acquisition, geological and geophysical, exploratory and development costs as we operated with reduced access to capital.

Our approved capital expenditure budget for 2001 is approximately $140 million after estimated proceeds from property conveyances and before indirect costs. Our budget includes approximately $70 million for exploration activities and $70 million for development activities. A very active Deepwater Gulf exploration program is underway, with funds budgeted to drill seven to ten wells. The exploration budget also anticipates additions to our Deepwater 3-D seismic database and our Deepwater leasehold position. The development budget includes funds for completion of our King Kong Deepwater Gulf exploitation project, development of the Aconcagua discovery and several development wells in currently-producing fields.

Our long-term debt outstanding as of December 31, 2000 was approximately $129.7 million, including $99.7 million of senior subordinated notes and $30.0 million drawn on our Revolving Credit Facility. Following our semi-annual borrowing base redetermination completed in October 2000, our borrowing base under the Revolving Credit Facility was reaffirmed at $70 million.

Our Revolving Credit Facility and the 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. In addition, restrictions in the Revolving Credit Facility and the senior subordinated notes effectively restrict us from using our assets or cash flow to satisfy interest or principal payments for our parent's credit facility with Enron.

In March and May of 2000, we received cash equity contributions by the sale of common stock to our Parent of $30 million and $25 million, respectively. The March equity contribution was used to reduce accounts payable and accrued liabilities, and the May equity contribution was used to repay our $25 million Senior Credit Facility with ENA. These equity contributions were made with proceeds from the Mariner Energy LLC three-year $112 million term loan with ENA. Due to certain restrictions with our Indenture and Revolving Credit Agreement, neither cash flows from operations nor from asset sales would be available to repay any portion of this term loan.

We expect to fund our activities for 2001 through a combination of cash flow from operations, borrowings under our Revolving Credit Facility, 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. We cannot assure you that anticipated growth will be realized, that our business will generate sufficient cash flow from operations or that future borrowings or equity capital will be available in an amount sufficient to enable us to service our indebtedness or make necessary capital expenditures. In addition, depending on the levels of our cash flow and capital expenditures, we may need to refinance a portion of the principal amount of our senior subordinated debt at or prior to maturity. However, we cannot assure you that we would be able to obtain financing on acceptable terms to complete a refinancing.

(e) Recent Accounting Pronouncements

Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities, is effective for all fiscal years beginning after June 15, 2000. SFAS 133, as amended and interpreted, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. All derivatives, whether designated in hedging relationships or not, will be required to be recorded on the balance sheet at fair value. If the derivative is designated in a fair-value hedge, the changes in the fair value of the derivative and the hedged item will be recognized in earnings. If the derivative is designated in a cash-flow hedge, changes in the fair value of the derivative will be recorded in other comprehensive incomes (OCI) and will be recognized in the income statement when the hedged item affects earnings. SFAS 133 defines new requirements for designation and documentation of hedging relationships as well as ongoing effectiveness assessments in order to use hedge accounting. For a derivative that does not qualify as a hedge, changes in fair value will be recognized in earnings.

The Company expects that at January 1, 2001, it will record $33.3 million charge in OCI as a cumulative transition adjustment for derivatives designated in cash flow-type hedges prior to adopting SFAS 133. The Company does not expect to record a cumulative transition adjustment to earnings relating to derivatives not designated as hedges prior to the adoption of SFAS 133.

The Company adopted the provisions of Staff Accounting Bulletin ("SAB") No. 101 issued by the staff of the Securities and Exchange Commission. The impact of adopting SAB No. 101 was not material to the Company.

In the fourth quarter of 2000, the Company adopted Emerging Issues Task Force Issue No. 00-10 ("EITF No. 00-10") Accounting for Shipping and Handling Fees and Costs. EITF No. 00-10 addresses how shipping and handling fees should be classified in the income statement. As a result of EITF No. 00-10, the Company has reclassified transportation expenses from oil and gas revenues to a separate line item. The amounts reclassified for the years ended December 31, 2000, 1999 and 1998 were $7.8 million, $2.0 million and $1.3 million, respectively.

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.

24

Item 8. Financial Statements and Supplementary Data

Index to Financial Statements

PAGE

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, 2000 and 1999 and the related statements of operations, stockholder's equity and cash flows for each of the three years in the period ended December 31, 2000. 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, 2000 and 1999, and the results of its operations and cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles general accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

DELOITTE & TOUCHE LLP

Houston, Texas
April 2, 2001

MARINER ENERGY, INC.
BALANCE SHEETS
(in thousands, except share data)

	December 31, 2000	December 31, 1999
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2,389	$ 123
Receivables	33,534	23,683
Prepaid expenses and other	5,991	4,891
Total current assets	41,914	28,697
PROPERTY AND EQUIPMENT:		
Oil and gas properties, at full cost:		
Proved	478,596	379,301
Unproved, not subject to amortization	61,068	81,897
Total	539,664	461,198
Other property and equipment	4,592	3,982
Accumulated depreciation, depletion and amortization	(254,396)	(199,233)
Total property and equipment, net	289,860	265,947
OTHER ASSETS, NET OF AMORTIZATION	3,653	2,868
TOTAL ASSETS	$335,427	$297,512
LIABILITIES AND STOCKHOLDER'S EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 37,600	$ 45,058
Accrued liabilities	15,144	10,600
Accrued interest	4,522	5,329
Total current liabilities	57,266	60,987
OTHER LIABILITIES	6,552	4,226
LONG-TERM DEBT:		
Senior Subordinated notes	99,722	99,673
Revolving Credit Facility	30,000	42,600

Affiliate Credit Facility	-	25,000
Total long-term debt	129,722	167,273
STOCKHOLDER'S EQUITY:		
Common stock, $1 par value; 2,000 and 1,000 shares authorized, 1,380 and 1,378 issued and outstanding, at December 31, 2000 and December 31, 1999, respectively	1	1
Additional paid-in-capital	227,318	172,318
Accumulated deficit	(85,432)	(107,293)
Total stockholder's equity	141,887	65,026
TOTAL LIABILITIES and STOCKHOLDER'S EQUITY	$335,427	$297,512

The accompanying notes are an integral part of these financial statements

27

MARINER ENERGY, INC.
STATEMENTS OF OPERATIONS
(in thousands)

	Year Ended December 31,		
	2000	1999	1998
REVENUES:			
Oil sales	$37,959	$8,888	$10,211
Gas sales	83,191	45,597	47,804
Total revenues	121,150	54,485	58,015
COSTS AND EXPENSES:			
Lease operating expense	17,192	11,453	9,858
Transportation expense	7,789	2,017	1,325
Depreciation, depletion and amortization	56,846	32,121	33,833
Impairment of oil and gas properties	-	-	50,800
Provisions for ligitation	-	-	2,800
General and administrative expense	6,549	5,396	4,749
Total costs and expenses	88,376	50,987	103,365
OPERATING INCOME	32,774	3,498	(45,350)
INTEREST:			
Income	124	36	313
Expense	(11,037)	(13,504)	(13,384)
INCOME (LOSS) BEFORE TAXES	21,861	(9,970)	(58,421)
PROVISION FOR INCOME TAXES	-	-	-

NET INCOME (LOSS)	$21,861	$(9,970)	$(58,421)
	=========	=========	=========

The accompanying notes are an integral part of these financial statements

MARINER ENERGY, INC.
STATEMENTS OF STOCKHOLDER'S EQUITY
(in thousands, except number of shares)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Deficit	Total Stockholder's Equity
Balance at December 31, 1997 .	1,000	$ 1	$ 96,075	$(38,902)	$ 57,174
Capital contribution -- proceeds from the sale of common stock of Parent		--	28,781	--	28,781
Net loss	--	--	--	(58,421)	(58,421)
Balance at December 31, 1998 .	1,000	1	124,856	(97,323)	27,534
Capital contribution	378	--	47,462	--	47,462
Net loss	--	--	--	(9,970)	(9,970)
Balance at December 31, 1999 .	1,378	1	172,318	(107,293)	65,026
Capital contribution	2	--	55,000	--	55,000
Net income				21,861	21,861
Balance at December 31, 2000 .	1,380	$ 1	$227,318	$(85,432)	$141,887

The accompanying notes are an integral part of these financial statements

MARINER ENERGY, INC.
STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31, 2000	1999	1998
OPERATING ACTIVITIES:			
Net income (loss)	$21,861	$(9,970)	$(58,42
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, depletion and amortization	57,538	32,838	33,76

Impairment of oil and gas properties	-	-	50,80
Provisions for litigation	-	-	2,80
Changes in operating assets and liabilities:			
Receivables	(9,851)	(8,119)	2,57
Other current assets	(1,100)	2,343	(3,60
Other assets	(785)	265	37
Accounts payable and accrued liabilities	(3,721)	7,027	11,25
Net cash provided by operating activities	63,942	24,384	39,54
INVESTING ACTIVITIES:			
Additions to oil and gas properties	(107,468)	(80,823)	(140,77
Proceeds from property conveyances	29,002	19,758	
Additions to other property and equipment	(610)	(682)	(1,07
Net cash used in investing activities	(79,076)	(61,747)	(141,85
FINANCING ACTIVITIES:			
Proceeds from (repayment of) revolving credit facility	(12,600)	(10,800)	39,40
Capital contributed by sale of stock to parent	55,000	23,284	28,78
Proceeds from (payments to) the affiliate credit facility	(25,000)	25,000	25,00
Net cash provided by financing activities	17,400	37,484	93,18
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	2,266	121	(9,12
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	123	2	9,13
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 2,389	$ 123	$

The accompanying notes are an integral part of these financial statements

MARINER ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS For the Years Ended
December 31, 2000, 1999 and 1998

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 public company incorporated in the United Kingdom. Pursuant to a stock purchase agreement dated April 1, 1996, Joint Energy Development Investments Limited Partnership ("JEDI"), which is an affiliate of Enron Capital & Trade Resources Corp. as of September 1, 1999 known as Enron North America Corp. ("ENA"), 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"). As a result of the sale of Hardy Oil & Gas USA Inc.'s common stock, the name 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 owns 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. 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. As a result of this limitation, permanent impairments of oil and gas properties of approximately $50,800,000 was recorded during 1998. No writedown was necessary in 2000 or 1999.

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 five to seven years.

Deferred Loan Costs -- Deferred loan costs, which are included in other assets, are stated at cost and amortized straight-line over their estimated useful lives, not to exceed the life of the related debt.

Income Taxes -- The Company's taxable income is included in a consolidated United States income tax return with Mariner Holdings Inc. 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 $3,885,000, $3,028,000 and $1,702,000 for the years ended December 31, 2000, 1999 and 1998, 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.

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 are deferred, as appropriate, until recognized as operating income in the Company's Statement of Operations as the physical production required by the contracts is delivered.

The net cash flows related to any recognized gains or losses associated with these hedges are reported as 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 required by the contracts is delivered.

The conditions to be met for a derivative instrument to qualify as a 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, 2000 and 1999, the estimated fair value of the Company's Senior Subordinated Notes was approximately $91,000,000 and $92,000,000, respectively. The estimated fair value was determined based on borrowing rates available at December 31, 2000 and 1999, 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 generally accepted accounting principles 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, 2000, sales of oil and gas to two purchasers, including an affiliate, accounted for 49% and 16% of total revenues. During the year ended December 31, 1999, sales of oil and gas to three purchasers, including an affiliate, accounted for 26%, 21% and 13% of total revenues. During the year ended December 31, 1998, sales of oil and gas to four purchasers accounted for 29%, 16%, 15% and 10% 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 years financial statements to conform to the current year presentation.

Recent Accounting Pronouncements -- Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities, is effective for all fiscal years beginning after June 15, 2000. SFAS 133, as amended and interpreted, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. All derivatives, whether designated in hedging relationships or not, will be required to be recorded on the balance sheet at fair value. If the derivative is designated in a fair-value hedge, the changes in the fair value of the derivative and the hedged item will be recognized in earnings. If the derivative is designated in a cash-flow hedge, changes in the fair value of the derivative will be recorded in other comprehensive incomes (OCI) and will be recognized in the income statement when the hedged item affects earnings. SFAS 133 defines new requirements for designation and documentation of hedging relationships as well as ongoing effectiveness assessments in order to use hedge accounting. For a derivative that does not qualify as a hedge, changes in fair value will be recognized in earnings.

The Company expects that at January 1, 2001, it will record $33.3 million charge in OCI as a cumulative transition adjustment for derivatives designated in cash flow-type hedges prior to adopting SFAS 133. The Company does not expect to record a cumulative transition adjustment to earnings relating to derivatives not designated as hedges prior to the adoption of SFAS 133.

The Company adopted the provisions of Staff Accounting Bulletin ("SAB") No. 101 issued by the staff of the Securities and Exchange Commission. The impact of adopting SAB No. 101 was not material to the Company.

In the fourth quarter of 2000, the Company adopted Emerging Issues Task Force Issue No. 00-10 ("EITF No. 00-10") Accounting for Shipping and Handling Fees and Costs. EITF No. 00-10 addresses how shipping and handling fees should be classified in the income statement. As a result of EITF No. 00-10, the Company has reclassified transportation expenses from oil and gas revenues to a separate line item. The amounts reclassified for the years ended December 31, 2000, 1999 and 1998 were $7.8 million, $2.0 million and $1.3 million, respectively.

2. RELATED-PARTY TRANSACTIONS

Sales to Affiliates -- For the years ending December 31, 2000, 1999 and 1998, sales to affiliates were approximately $73.4 million, $16.2 million and $8.9 million, respectively.

Receivables from Affiliates - At December 31, 2000 and 1999, receivables from affiliates were $993,533 and $76,100, respectively.

Affiliate Transactions Subsequent to the Acquisition -- Enron Corp.("Enron") is the parent of ENA, and an affiliate of Enron and ENA is the general partner of JEDI. Accordingly, Enron may be deemed to control JEDI, Mariner Energy LLC, Mariner Holdings and the Company. In addition, eight of the Company's directors are officers of Enron or affiliates of Enron. Enron and certain of its subsidiaries and other affiliates collectively participate in many phases of the oil and natural gas industry and are, therefore, competitors of the Company. In addition, ENA and JEDI have provided, and may in the future provide, and ENA Securities Limited Partnership has assisted, and may in the future assist, in arranging financing to non-affiliated participants in the oil and natural gas industry who are or may become competitors of the Company. Because of these various conflicting interests, ENA, the Company, JEDI and the members of the Company's management who are also 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.

Transportation Contract - In 1999 the Company constructed a 29 mile flowline from a third party platform to the Mississippi Canyon 718 subsea well. After commissioning, MEGS LLC, an Enron affiliate, purchased the flowline from the Company and its joint interest partners. The Company received $8.8 million in cash proceeds which were offset against the cost of constructing the flowline. No gain or loss was recognized. In addition the Company entered into a firm transportation contract at a rate of $0.26 per MMbtu with MEGS LLC to transport its share of 86 Bcf of natural gas from the commencement of production through March 2009. For the year ending December 31, 2000 the Company paid $4.3 million on this contract. The Company's working interest at December 31, 2000 was 51%.

The Company expects that from time to time it will engage 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, engaging in hydrocarbon price hedging arrangements and entering into other oil and gas related or financial transactions. For example, the Company has entered into several agreements with Enron or affiliates of Enron for the purpose of hedging oil and natural gas prices on the Company's future production. Certain of the Company's debt instruments 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 contained in an agreement with a third party.

3. 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 provides for a maximum $150 million revolving credit loan. The available borrowing base under the Revolving Credit Facility is currently $70 million and is subject to periodic redetermination. The Revolving Credit Facility has an outstanding balance of $30.0 million at December 31, 2000. On June 28, 1999, the Revolving Credit Facility was amended to extend the maturity date from October 1, 1999 to October 1, 2002 and to pledge certain Mariner interests to secure the Revolving Credit Facility.

Borrowings under the Revolving Credit Facility bear interest, at the option of the Company, at either (i) LIBOR plus 0.75% to 1.25% (depending upon the level of utilization of the Borrowing Base) or (ii) the higher of (a) the agent's prime rate or (b) the federal funds rate plus 0.5%. The effective interest rate at December 31, 2000 was 8.49%. The Company incurs a quarterly commitment fee ranging from 0.25% to 0.375% per annum on the average unused portion of the Borrowing Base, depending upon the level of utilization.

The Revolving Credit Facility, as amended, contains various restrictive covenants which, among other things, restrict the payment of dividends, limit the amount of debt the Company may incur, limit the Company's ability to make certain loans and investments, limit the Company's ability to enter into certain hedge transactions and provide that the Company must maintain specified relationships between cash flow and fixed charges and cash flow and interest on indebtedness. As of December 31, 2000, the Company was in compliance with all such requirements.

Affiliate Credit Facility -- In April 1999, the Company established a $25 million borrowing-based short-term credit facility with ENA to obtain funds needed to execute the Company's 1999 capital expenditure program and for short-term working capital needs. The facility accrued interest at an annual rate of LIBOR plus 2.5% and required a structuring fee of 1% of the committed amount. The effective interest rate for the year ended December 31, 2000 and 1999 was 8.52% and 8.69%, respectively. The facility matured on May 1, 2000 and was repaid from a capital contribution from the Company's parent. Accordingly, the facility was classified as long-term debt as of December 31, 1999.

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 the 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, including indebtedness under the Revolving Credit Facility.

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, 2000, 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, 2000, 1999 and 1998 was $15.3, $15.1 million and $15.7 million, respectively.

4. 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 will 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 2,433,600.

During the years ended December 31, 2000, 1999 and 1998, the Mariner Energy LLC granted stock options ("Options") of 39,144, 215,748 and 329,172, respectively. No options have been exercised, however, 66,828 options have been canceled during the three year period. At December 31, 2000, options to purchase 2,200,620 shares had been issued at an exercise price ranging from $8.33 to $14.58 per share. These Options generally become exercisable as to one-fifth to one-third on each of the first three or five anniversaries of the date of grant. The Options expire from seven years to ten years after the date of grant.

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, 2000 would have been reduced by $422,000 to $21,439,000 and the net loss for the years ending 1999 and 1998 would have decreased $428,000 and $357,000, 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 6.46% for the year ending December 31, 2000 and 6.46% for the years ending December 31, 1999 and 1998. Stock options available for future grant amounted to 232,980 shares at December 31, 2000. Exercisable stock options amounted to 1,625,582 shares at December 31, 2000.

35

Capital Contribution -- In March and May of 2000, we received cash equity contributions by the sale of common stock to our Parent of $30 million and $25 million, respectively. The March equity contribution was used to reduce accounts payable and accrued liabilities, and the May equity contribution was used to repay the Affiliate Credit Facility with ENA. These equity contributions were made with proceeds from the Mariner Energy LLC three-year $112 million term loan with ENA. Due to certain restrictions with our Indenture and Revolving Credit Agreement, neither cash flows from operations nor from asset sales would be available to repay any portion of this term loan.

5. 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, shall be determined annually and shall 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 2000, 1999 and 1998, the Company contributed $251,017, $180,000 and $182,000, 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, 2000, 1999 and 1998 were $2.9 million, $1.0 million and $1.0 million, respectively.

6. COMMITMENTS AND CONTINGENCIES

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, 2000 are as follows (in thousands):

2001	1,345
2002	1,346
2003	654
2004	110
Total	$3,455

Rental expense, before capitalization, was approximately $1,228,000, $1,170,000 and $1,000,000 for the years ended December 31, 2000, 1999 and 1998, respectively.

Hedging Program -- The Company conducts a hedging program with respect to its sales of crude oil and natural gas using various instruments whereby monthly settlements are based on the differences between the price or range of prices specified in the instruments and the settlement price of certain crude oil and natural gas futures contracts quoted on the open market. The instruments utilized by the Company differ from futures contracts in that there is no contractual obligation which requires or allows for the future delivery of the product.

The following table sets forth the results of hedging transactions during the periods indicated:

	Year Ended December 31,		
	2000	1999	1998
Natural gas quantity hedged (Mmbtu)	19,569	18,818	9,800
Increase (decrease) in natural gas sales (thousands)	($21,364)	($ 6,741)	$ 2,337

Crude oil quantity hedged (MBbls)	1,059	389	--
Increase (decrease) in crude oil sales (thousands) .	($14,053)	($ 2,152)	--

The following tables set forth the Company's position as of December 31, 2000.

Time Period	Notional Quantities	Price Floor	Price Ceiling	Price Fixed	Fair Value (in millions)
Natural Gas (MMBtu)					
January 1 - September 30, 2001					
Collar purchased	4,216	$3.50	$4.92		(8.5)
Put option purchased	4,216	$3.50			--
Fixed price swap purchased	3,376			$2.18	(18.0)
October 1 - December 31, 2001					
Fixed price swap purchased	774			2.18	(2.5)
January 1 - December 31, 2002					
Fixed price swap purchased	1,831			2.18	(4.3)
Total					($33.3)

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.

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.

7. INCOME TAXES

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

	2000		1999		1998	
	$	%	$	%	$	%

Income (loss) before income taxes	21,861	--	(9,970)	--	(58,421)	--
Income tax expense (benefit) computed at statutory rates....	7,651	35	(3,490)	(35)	(20,447)	(35
Change in valuation allowance..	(8,074)	(34)	2,330	23	18,804	32
Other.........................	(423)	(1)	1,160	12	1,643	3
Tax Expense...................	--	--	--	--	--	--

No federal income taxes were paid by the Company during the years ended December 31, 2000, 1999 or 1998.

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):

	2000	1999	1998
Deferred tax assets:			
Net operating loss carry forwards	$ 44,939	$ 43,401	$ 34,771
Valuation allowance	(28,056)	(36,130)	(33,800)
Total net deferred tax assets	16,883	7,271	971
Deferred tax liabilities --			
Differences between book and tax bases of properties	(16,883)	(7,271)	(971)
Total net deferred taxes	$ --	$ --	$ --

As of December 31, 2000, the Company has a cumulative net operating loss carryforward ("NOL") for federal income tax purposes of approximately $128 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.

8. 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 ended December 31, 2000	Year ended December 31, 1999	Year ended December 31, 1998
Oil and gas sales..................	$121,150	$54,485	$58,015
Production costs...................	(17,192)	(11,453)	(9,858)
Transportation.....................	(7,789)	(2,017)	(1,325)
Depreciation, depletion and amortization.......................	(56,846)	(32,121)	(33,833)
Impairment of oil and gas properties	--	--	(50,800)
Results of operations..........	$ 39,323	$8,894	$(37,801)

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

	Year ended December 31, 2000(1)	Year ended December 31, 1999(1)	Year ended December 31, 1998
Property acquisition costs			
Unproved properties..........	$1,724	$2,982	$43,143
Exploration costs................	16,005	13,522	35,674
Development costs................	60,738	44,561	61,960
Total costs, net of proceeds from property conveyances...........	$78,467	$61,065	$140,777
Depreciation, depletion and amortization rate per equivalent Mcf before impairment	$1.57	$1.29	$1.40

(1) Property acquisition costs, exploration costs and development costs are net of proceeds from property conveyances of $9.6 million, $5.0 million, $14.4 million and $7.5 million, $0 and $12.3 for the years ending December 31, 2000 and 1999, respectively.

The Company capitalizes internal costs associated with exploration activities in progress. These capitalized costs were approximately $11,625,000, $9,440,000 and $6,386,000 for the years ended December 31, 2000, 1999 and 1998, respectively.

The following table summarizes costs related to unevaluated properties which have been excluded from amounts subject to amortization at December 31, 2000. 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, 2000	1999	1998	Total at December 31, 2000
Property Acquisition costs	$5,652	$8,802	$42,815	$57,269
Exploration costs	3,143	646	10	3,799
Total.......	$8,795	$9,448	$42,825	$61,068

Approximately 99% of excluded costs at December 31, 2000 relate to activities in the Deepwater Gulf of Mexico and the remaining 1% relates to activities in the Gulf of Mexico shallow waters and onshore areas near the Gulf.

9. 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, 2000 were reserves expected to be recovered from wells for which certain drilling and completion operations had occurred as of that date, 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)	Gas (Mcf)	Natural Gas Equivalent (Mcfe)
December 31, 1997	6,630	121,366	161,146
Revisions of previous estimates	(836)	(410)	(5,426)
Extensions, discoveries and other additions	4,351	27,416	53,522
Production	(786)	(19,477)	(24,193)
December 31, 1998	9,359	128,895	185,049
Revisions of previous estimates	715	(5,098)	(808)
Extensions, discoveries and other additions	1,225	24,972	32,322
Sale of reserves in place	(742)	(8,856)	(13,308)
Production	(630)	(21,123)	(24,903)
December 31, 1999	9,927	118,790	178,352
Revisions of previous estimates	324	(13,255)	(11,311)
Extensions, discoveries and other additions	4,123	24,649	49,387
Sales of reserves in place	(215)	(673)	(1,963)
Purchase of reserves in place	--	25,455	25,455
Production	(1,762)	(25,710)	(36,282)
December 31, 2000	12,387	129,256	203,638

Estimated Quantities of Proved Developed Reserves
(in thousands)

	Oil (Bbl)	Gas (Mcf)	Natural Gas Equivalent (Mcfe)
December 31, 1998	2,886	86,024	103,340
December 31, 1999	3,799	82,760	105,554
December 31, 2000	5,540	61,623	94,863

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.

41

Standardized Measure of Discounted Future Net Cash Flows
(in thousands)

	Year ended December 31,		
	2000	1999	199
Future cash inflows	$ 1,758,734	$ 490,239	$ 383,
Future production costs	(161,617)	(122,681)	(103,
Future development costs	(162,277)	(70,774)	(81,
Future income taxes	(372,059)	--	
Future net cash flows	1,062,781	296,784	199,
Discount of future net cash flows at 10% per annum	(290,075)	(85,558)	(51,
Standardized measure of discounted future net cash flows	$ 772,705	$ 211,226	$ 147,

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, 2000, 1999 and 1998, used in the above table, were $26.36, $23.85 and $10.36 per Bbl, respectively, and $11.32, $2.23 and $2.22 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 ended December 31,

	2000	1999	1998
Sales and transfers of oil and gas produced, net of production costs	$ (96,169)	$(41,015)	$(46,832)
Net changes in prices and production costs ...	503,871	77,532	(67,815)
Extensions and discoveries, net of future development and production costs	214,022	33,357	23,730
Development costs during period and net change in development costs	39,736	(3,661)	30,799
Revision of previous quantity estimates	(13,365)	(984)	(6,846)
Purchases of reserves in place	157,657	--	--
Sales of reserves in place	(2,584)	(15,535)	--
Net change in income taxes	(270,510)	--	27,193
Accretion of discount before income taxes	29,678	19,900	20,365
Changes in production rates (timing) and other	(857)	(5,997)	(9,424)
Net change	$ 561,479	$ 63,597	$ (28,830)

Item 9. Changes In and Disagreements With Accountants On Accounting and Financial Disclosure

None

42

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 15, 2001. 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
Robert E. Henderson	48	Chairman of the Board, President and Chief Executive Offi
Richard R. Clark	45	Executive Vice President and Director
L. V. "Bud" McGuire	58	Senior Vice President of Operations and Director
Michael W. Strickler	45	Senior Vice President of Exploration and Director
Frank A. Pici	45	Vice President of Finance and Chief Financial Officer
Gregory K. Harless	51	Vice President of Oil and Gas Marketing
W. Hunt Hodge	45	Vice President of Administration
Tom E. Young	42	Vice President of Business Development
Kelly D. Zelikovitz	42	General Counsel and Secretary
David S. Huber	50	Consultant and Director of Deepwater Development

Raymond M. Bowen	45	Director
Richard B. Buy	48	Director
Timothy J. Detmering	42	Director
Jeffrey M. Donahue, Jr.	38	Director
Craig A. Fox	45	Director
Mark E. Haedicke	45	Director
Jesus G. Melendrez	41	Director
Jeffrey B. Sherrick	46	Director

Mr. Henderson has been our Chairman of the Board since May 1996, President and Chief Executive Officer since 1987 and a director since 1985. Mr. Henderson served as a director of London-based Hardy Plc, our former parent company, between 1989 and 1996. From 1984 to 1987, he served us or predecessors as Vice President of Finance and Chief Financial Officer. From 1976 to 1984, he held various positions with ENSTAR Corporation, including Treasurer of ENSTAR Petroleum, which operated in the U.S. and Indonesia.

Mr. Clark has served us in various engineering and operations activities since 1984 and has been Executive Vice President since May 1998. He served as Senior Vice President of Production from 1991 until May 1998 and has served as a director since 1988. Prior to joining us he worked as a Production Engineer in the Offshore Production Group of Shell Oil Company.

Mr. McGuire joined us in June 1998 as Senior Vice President-Operations. Prior to joining us, Mr. McGuire was Vice President-Operations for Enron Oil & Gas International, Inc. Before joining EOGI, he served five years with Kerr-McGee Corporation as Senior Vice President over worldwide production operations. His experience prior to Kerr-McGee included Hamilton Oil Corporation from 1981 to 1991, where he served as Operations Manager then as Vice President of Operations for Hamilton in the North Sea. He began his career in 1966 with Conoco.

Mr. Strickler joined us in 1984 and has served since such time in our geological and exploration activities. He has served as Senior Vice President of Exploration since 1991 and a director since 1989. Prior to joining us, Mr. Strickler worked for several independent oil companies as an exploration geologist, generating and evaluating exploration plays in the Gulf Coast, Mid Continent, Rocky Mountains, West Texas and several overseas basins.

Mr. Pici became Vice President of Finance and Chief Financial Officer in December 1996. Prior to joining us, Mr. Pici was employed by Cabot Oil & Gas Corporation holding several positions since 1989, including Corporate Controller. Prior to joining Cabot Oil & Gas, he was Controller of a privately-held independent oil & gas company, and he began his career with Coopers & Lybrand. He is a Certified Public Accountant.

Mr. Harless has served as Vice President of Oil and Gas Marketing since 1990. Prior to joining us in 1988, he was Vice President of Marketing and Regulatory Affairs of Enron Oil and Gas Company and District Operating Manager with Coastal States Oil & Gas.

Mr. Hodge has served as Vice President of Administration since 1991. Prior to joining us in 1985, he was Purchasing Manager of Santa Fe Minerals Company.

Mr. Young has served as Vice President of Business Development since January 2001. Mr. Young also served as our Vice President of Land from November 1998 to January 2001, and as Manager of Land for the Central Gulf and as a landman since joining us in 1985. Prior to joining us, Mr. Young served as a landman for TXO Production Corp.

Ms. Zelikovitz has been our General Counsel and Secretary since August 2000. She is in private practice and has a contractual relationship with us. Prior to May 1998, she held various legal and management positions with Mobil Oil Corporation, Greenhill Petroleum Corporation, Union Texas Petroleum Corporation, and with a Houston-based law firm.

Mr. Huber, a consultant, began his association with us in 1991 as a deepwater project management consultant and is presently our Director of Deepwater Developments. 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. Bowen has served as a director since January 2000. He is currently Managing Director of ENA and Co-Head of the Commercial Transactions Group 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. Buy has served as a director since January 1998. Since 1994 he has been an employee of ENA or its affiliates, currently serving as Senior Vice President and Chief Risk Officer of Enron Corp. Prior to joining Enron, Mr. Buy was a Vice President at Bankers Trust in the Energy Group.

Mr. Detmering has served as a director since March 2001. Since 1994 he has been an employee of ENA or its affiliates, currently serving as a Managing Director of Corporate Development. Prior to joining Enron, Mr. Detmering was an Engineer with ARCO Oil & Gas Co. and an Investment Banker with Wasserstein Perella and Co.

Mr. Donahue has served as a director since August 2000. He joined Enron in April 1998 as Vice President responsible for Corporate Development of ENA. Prior to joining ENA, Mr. Donahue was an investment banker focusing on the energy industry at UBS Securities, CS First Boston and Kidder Peabody. He was also a management consultant with McKinsey & Company and an economic policy consultant at ICF Incorporated.

Mr. Fox has served as a director since March 2001. He is currently Vice President and Technical Manager for Enron 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. Haedicke has served as a director since October 1998. He is currently Managing Director, Legal, of ENA. Mr. Haedicke also serves on the board of directors of the International Swaps and Derivatives Association, Inc. and he holds a seat on the New York Mercantile Exchange. He has been associated with ENA since its inception in 1990.

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 which involved loan restructuring and power marketing.

Mr. Sherrick has served as a director since January 2000. He is currently the President and Chief Executive Officer of Enron Global Exploration & Production Inc. and has held various management positions with Enron Oil & Gas Company, or one of its affiliates, since 1993.

The Shareholders' Agreement requires that the Board of Directors include at least three nominees of the Management Stockholders. Currently, those three representatives are Messrs. Henderson, Clark and Strickler. The remaining board members are to include nominees of JEDI. See "Certain Relationships and Related Transactionson page 51.

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, 2000. These individuals are sometimes referred to as the "named executive officers".

Name and Principal Position		Annual Compensation: Salary	Annual Compensation: Other Annual Compensation(1)	Current Year Compensation Under our Overriding Royalty Program(2)	All Othe Compensatio
Robert E. Henderson	2000	$295,000	$ 3,680	$ 8,690	$ 270
President and	1999	285,000	6,400	5,438	396
Chief Executive Officer ..	1998	285,000	4,800	1,292	522
Richard R. Clark	2000	235,000	3,680	5,596	210
Executive Vice President	1999	225,000	6,400	3,508	243
of Production	1998	225,000	4,800	821	306
Michael W. Strickler	2000	198,000	3,680	5,596	188
Senior Vice President	1999	190,000	6,400	3,508	243
of Exploration	1998	182,000	4,800	821	306
L. V. "Bud" McGuire (4)	2000	198,000	3,680	0	114,774
Senior Vice President	1999	190,000	4,433	0	44,573
of Operations	1998	110,834	0	0	788
Frank A. Pici	2000	167,000	3,680	3,440	180
Vice President of Finance ...	1999	160,000	6,400	2,043	243
and Chief Financial Officer .	1998	160,000	4,380	356	306

(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 2000, 1999 or 1998.

(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 paid during the year.

(4) Mr. McGuire joined us in June 1998 and is eligible for guideline bonuses under our incentive compensation plan. He does not participate in the Overriding Royalty Program.

Options

Mariner Energy LLC granted 0 and 48,624 options to purchase common shares to Mr. McGuire in 2000 and 1999, respectively. None of the named executive officers exercised stock options in 2000. The following table shows the number and value of options owned by our named executive officers at December 31, 2000. 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, 2000	
	Exercisable	Unexercisable
Robert E. Henderson.........	190,896	47,724
Richard R. Clark............	134,342	33,586
L. V. "Bud" McGuire.........	85,116	72,948
Michael W. Strickler........	134,342	33,586
Frank A. Pici...............	43,848	29,232

Share Option Plan

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 us and our shareholders. 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 2,200,620 common shares are outstanding under the 1996 plan, 1,625,582 of which are currently exercisable. The exercise price for outstanding options to purchase an aggregate of 1,683,386 shares under the 1996 plan is $8.33 per share, and the exercise price for options to purchase the remaining outstanding aggregate of 517,234 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

We and each of the named executive officers are parties to employment agreements that expire on September 30, 2002. Following the expiration date of an employment agreement or the expiration of any extended term, the employment agreements extend for six months, unless notice of termination is given by either us or the named executive officer at least six months before the end of the initial term or extended term, as applicable.

Under the employment agreements, the current annual salaries are $295,000 for Mr. Henderson, $235,000 for Mr. Clark, $198,000 for Mr. Strickler, $198,000 for Mr. McGuire and $167,000 for Mr. Pici. Our board of directors may in its discretion increase their salaries.

46

The named executive officers are entitled to participate in any medical, dental, life and accidental death and dismemberment insurance programs and retirement, pension, deferred compensation and other benefit programs instituted by us from time to time. The employees are also entitled to vacation, reimbursement of specified expenses and, depending on the employment agreement, an automobile allowance and reimbursement for expenses related to the use of that vehicle. As incentive compensation, the named executive officers, except for Mr. McGuire, are entitled to receive overriding royalty interests in some oil and gas prospects that we have acquired under our overriding royalty program. Mr. McGuire is entitled to receive annual cash bonuses and incentive stock option awards under an incentive compensation plan separate from other named executive officers.

If we terminate a named executive officer's employment agreement without cause, if the named executive officer terminates his employment contract for good reason, or if we give notice of termination on the expiration of his term of employment, then the named executive officer will be entitled to, among other things:

- the value of his salary and other benefits through the end of the initial term or any extended term of the employment agreement;

- a lump sum cash payment equal to 12 months salary in the case of Mr. Henderson, nine months salary in the case of Messrs. Clark, Strickler and McGuire and six months salary in the case of Mr. Pici plus, in the case of Mr. McGuire, an amount equal to 40% of nine months salary;

- a lump sum cash payment equal to all earned and unused vacation time for the previous year and the then current year;

- an assignment of his vested interests under our overriding royalty program, if eligible; and

- in the case of Mr. McGuire, a lump sum payment equal to any unpaid bonus from prior years under our incentive compensation plan, plus, in lieu of any bonus for subsequent years, an amount equal to 40% of his base salary through the end of the remaining term of his employment agreement.

If a named executive officer's employment agreement is terminated by the named executive officer without good reason, the named executive officer gives notice of termination on the expiration of his term of employment or if we consent to a request by the named executive officer to terminate his employment agreement before the expiration of his term, he will be entitled to:

- the value of his salary and benefits through the date that his employment agreement is terminated;
- a lump sum cash payment equal to all earned and unused vacation time for the previous year and the then current year;
- an assignment of his vested interests in our overriding royalty program through the date of termination, if eligible; and
- in the case of Mr. McGuire, a lump sum payment equal to any unpaid bonus from prior years under our incentive compensation plan, plus, in lieu of any bonus for subsequent years, an amount equal to 40% of his base salary through the end of the remaining term of his employment agreement.

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; and
- assign to him his vested interests in our overriding royalty program through the date of termination, if eligible.

To the extent any amounts paid under an employment agreement are subject to the "golden parachutes" excise tax, those amounts are grossed-up to cover the excise tax and any applicable taxes on the gross-up amount.

Each named executive officer has agreed that during the term of his employment agreement, and, if the named executive officer's employment agreement is terminated by us for cause or terminated by the named executive officer other than for good reason, for 12 months after the term expires in the case of Messrs. Henderson, Clark, Strickler and McGuire and six months after the term expires in the case of Mr. Pici, he will not compete with us for business or hire away our employees.

For purposes of the employment agreements with the named executive officers, "good reason" means:

- The assignment to the employee of any duties materially inconsistent with the employee's position, authority, duties or responsibilities with us or any other action that results in a material diminution in, or interference with, such position, authority, duties or responsibilities, if the assignment or action is not cured within 30 days after the employee has provided us with written notice;

- The failure to continue to provide the employee with office space, related facilities and support personnel (a) that are commensurate with the employee's responsibilities to, and position with, us and not materially dissimilar to the office space, related facilities and support personnel provided to our other employees having comparable responsibilities or (b) that are physically located at our principal executive offices, if that failure is not cured within 30 days after the employee has provided us with written notice;

- Any (a) reduction in the employee's monthly salary, (b) reduction in, discontinuance of, or failure to allow or continue to allow the employee's participation in, our incentive compensation program, or (c) reduction in, or failure to allow or continue the employee's participation in, any employee benefit plan in which the employee is participating or is eligible to participate before the reduction or failure, and that reduction, discontinuance or failure is not cured within 30 days after the employee has provided us with written notice;

- The relocation of the employee's or our principal office and principal place of the employee's performance of his duties and responsibilities to a location more than 50 miles outside of the central business district of Houston, Texas; or

- A breach of any material provision of the employment agreement that is not cured within 30 days after the employee has provided us with written notice.

Change of Control Agreements

We have issued each of the named executive officers' change of control agreements. Under these agreements, if a change of control occurs and the named executive officer's employment is terminated without cause or for good reason within 18 months of the change of control, Messrs. Henderson, Clark, McGuire, Pici and Strickler are entitled to receive, if the change in control is due to an acquisition of us by another company, three and one-half times their base salary and targeted annual incentive bonus, if applicable. The severance payment will be calculated assuming we satisfy the applicable base target for a particular year for the targeted annual incentive bonus. The ultimate payment due under the change of control agreements will be the greater of the payment calculated under the change of control agreements or the compensation due for the remaining balance under the employment agreements. To the extent any amounts paid under the change in control agreemens are subject to the "golden parachutes" excise tax, those amounts are grossed-up to cover the excise tax and any applicable taxes on the gross-up amount.

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 0.09375% to 0.23250% before payout and from 0.37500% to 0.93000% after payout for the named executive officers.

If all or a portion of our working interest in a prospect is sold or farmed out to unaffiliated third parties 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, some of which were paid by third parties, from overriding royalty interests we granted to the officers during the last 15 years.

	Aggregate Cash Amounts Received from Previously Assigned Overriding Royalty Interests(1)		
Name	2000	1999	1998
Robert E. Henderson........	$502,155	$227,054	$354,857
Richard R. Clark...........	301,702	137,774	218,077
Michael W. Strickler.......	298,452	131,103	212,803
Frank A. Pici..............	70,399	1,093	0

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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".

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 1, 2001, there were 13,928,308 common shares of Mariner Energy LLC outstanding.

Title of Class	Name and Address of Benefical Owner	Nature of Beneficial Owner	Amount and Percent of Class
Common Stock of Mariner Energy LLC	Joint Energy Development Investments Limited Partnership (1) 1400 Smith Street Houston, TX 77002	13,334,186	95.7%

(1) 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 1, 2000, with respect common shares of Mariner Energy LLC beneficially owned by each of our directors, our 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
Robert E. Henderson..............	84,840	*
Richard R. Clark.................	61,440	*
L. V. "Bud" McGuire..............	6,120	*
Michael W. Strickler.............	61,440	*
Frank A. Pici....................	20,472	*
David S. Huber...................	61,440	*
Raymond M. Bowen.................	0	*
Richard B. Buy...................	0	*
Timothy J. Detmering.............	0	*
Jeffrey M. Donahue, Jr...........	0	*
Craig A. Fox.....................	0	*
Mark E. Haedicke.................	0	*
Jesus Melendrez..................	0	*

Jeffrey B. Sherrick..............	0	*
All directors and executive officers and key consultant as a group (17 persons)	347,508	2.49%

* 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 Affiliates

Enron is the parent of ENA, and an affiliate of Enron and ENA is the general partner of JEDI. Accordingly, Enron may be deemed to control JEDI and us. See "Ownership of Securities". In addition, eight of the Company's directors are officers of Enron or of affiliates of Enron: Mr. Bowen is a Managing Director of ENA, Mr. Buy is Senior Vice President and Chief Risk Officer of Enron Corp., Mr. Detmering isa Managing Director of ENA, Mr. Donahue is a Vice President of ENA, Mr. Fox is a Vice President for Enron Capital Resources, Mr. Haedicke is a Managing Director of ENA, Mr. Melendrez is a Vice President of ENA, and Mr. Sherrick is President and Chief Executive Officer of Enron Global Exploration and Production, Inc.

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, and may in the future assist, 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.

Under the Revolving Credit Facility, Mariner has covenanted that it will not engage in any transaction with any of its affiliates (including Enron, ENA, JEDI and affiliates of such entities) providing for the rendering of services or sale of property unless such transaction is as favorable to such party as could be obtained in an arm's-length transaction with an unaffiliated party in accordance with prevailing industry customs and practices. The Revolving Credit Facility excludes from this covenant (i) any transaction permitted by the Shareholders' Agreement, (ii) the grant of options to purchase or sales of equity securities to directors, officers, employees and consultants of Mariner and (iii) the assignment of any overriding royalty interest pursuant to an employee incentive compensation plan.

The Indenture, dated as of August 1, 1996, between Mariner and United States Trust Company of New York (the "Indenture"), under which the Senior Subordinated Notes were issued, contains similar restrictions. Under the Indenture, Mariner Energy, Inc. has covenanted not to engage in any transaction with an affiliate unless the terms of that transaction are no less favorable to Mariner than could be obtained in an arm's-length transaction with a nonaffiliate. Further, if such transaction involves more than $1 million, it must be approved in writing by a majority of Mariner's disinterested directors, and if such a transaction involves more than $5 million, it must be determined by a nationally recognized banking firm to be fair, from a financial standpoint, to Mariner. However, this covenant is subject to several significant exceptions, including, among others, (i) certain industry-related agreements made in the ordinary course of business where such agreements are approved by a majority of Mariner's disinterested directors as being the most favorable of several bids or proposals, (ii) transactions under employment agreements or compensation plans entered into in the ordinary course of business and consistent with industry practice and (iii) certain prior transactions. Mariner expects that from time to time it will engage 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, engaging in hydrocarbon price hedging arrangements and entering into other oil and gas related or financial transactions. For example, Mariner has entered into several agreements with Enron or affiliates of Enron for the purpose of hedging oil and natural gas prices on Mariner's future production. Mariner believes that its current agreements with Enron and its affiliates are, and anticipates that, but can provide no assurances that, any future agreements with Enron and its affiliates will be, on terms no less favorable to Mariner than would be contained in an agreement with a third party.

Mariner Energy LLC Credit Facility with ENA

Our parent established the ENA Credit Facility to provide us with additional capital. The ENA Credit Facility provides for unsecured, subordinated loans to our parent up to $50 million, bearing interest at LIBOR plus 4.5%, payable monthly. In addition, upon any draw against the facility, our parent must pay a structuring fee equal to 4% of the principal amount of the borrowing. This agreement is expected to be repaid in full at maturity on April 30, 2000 through a capital contribution from our parent.

Affiliate Credit Facility

In April 1999, the Company established a $25 million borrowing-based short-term credit facility with ENA to obtain funds needed to execute the Company's 1999 capital expenditure program and for short-term working capital needs. The facility accrued interest at an annual rate of LIBOR plus 2.5% and required a structuring fee of 1% of the committed amount. The effective interest rate for the year ended December 31, 2000 and 1999 was 8.52% and 8.69%, respectively. The facility matured on May 1, 2000 and was repaid from a capital contribution from the Company's parent. Accordingly, the facility was classified as long-term debt as of December 31, 1999.

Capital Contribution

In March and May of 2000, we received cash equity contributions by the sale of common stock to our Parent of $30 million and $25 million, respectively. The March equity contribution was used to reduce accounts payable and accrued liabilities, and the May equity contribution was used to repay the Affiliate Credit Facility with ENA. These equity contributions were made with proceeds from the Mariner Energy LLC three-year $112 million term loan with ENA. Due to certain restrictions with our Indenture and Revolving Credit Agreement, neither cash flows from operations nor from asset sales would be available to repay any portion of this term loan.

Firm Transportation Contract

In 1999 we constructed a 29 mile flowline from a third party platform to the Mississippi Canyon 718 subsea well. After commissioning the flowline, MEGS LLC, an Enron affiliate, purchased the flowline from us and our joint interest partners. We received $8.8 million in cash proceeds which were offset against the cost of constructing the flowline. No gain or loss was recognized. In addition, we entered into a firm transportation contract with MEGS LLC at a rate of $0.26 per Mcf to transport our share of 86 Bcf of natural gas from the commencement of production through March 2009. For the year ending December 31, 2000 the Company paid $4.3 million on this contract. Our working interest increased from 37% to 51% after the project reached payout in the third quarter of 2000.

PART IV

Item 14. 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.).

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.

10.4(a)+Amended and Restated Employment Agreement, dated June 27, 1996, between the Registrant and Robert E. Henderson.

10.5(a)+Amended and Restated Employment Agreement, dated June 27, 1996, between the Registrant and Richard R. Clark.

10.6(a)+Amended and Restated Employment Agreement, dated June 27, 1996, between the Registrant and Michael W. Strickler.

10.7*+ Amended and Restated Employment Agreement, dated January 1, 1997, between the Registrant and Tom E. Young.

10.8*+ Amended and Restated Employment Agreement, dated December 27, 1998, between the Registrant and Gregory K. Harless.

10.9*+ Amended and Restated Employment Agreement, dated December 27, 1998, between the Registrant and W. Hunt Hodge.

10.10(a)+ Amended and Restated Consulting Services Agreement, dated June 27, 1996, between the Registrant and David S. Huber.

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.

10.17*+ Amended and Restated Employment Agreement, dated as of December 1, 1998, between the Registrant and Frank A. Pici.

10.18*+ Amended and Restated Employment Agreement, dated as of June 1, 1998, between the Registrant and L.V. Bud McGuire.

10.19(e)Third Amendment to Amended and Restated Employment Agreement, effective as of October 1, 1999, between Mariner Energy, Inc. and Richard R. Clark.

10.20(e)Fourth Amendment to Amended and Restated Employment Agreement, effective as of October 1, 1999, between Mariner Energy, Inc. and Gregory K. Harless.

10.21(e)Third Amendment to Amended and Restated Employment Agreement, effective as of October 1, 1999, between Mariner Energy, Inc. and Robert E. Henderson.

10.22(e)Fourth Amendment to Amended and Restated Employment Agreement, effective as of October 1, 1999, between Mariner Energy, Inc. and William Hunt Hodge.

10.23(e)First Amendment to Amended and Restated Consulting Services Agreement, effective as of October 1, 1999, between Mariner Energy, Inc. and David S. Huber.

10.24(e)First Amendment to Employment Agreement, effective as of October 1, 1999, between Mariner Energy, Inc. and L.V. McGuire.

10.25(e)Third Amendment to Employment Agreement, effective as of October 1, 1999, between Mariner Energy, Inc. and Frank A. Pici.

10.26(e)Fourth Amendment to Amended and Restated Employment Agreement, effective as of October 1, 1999, between Mariner Energy, Inc. and Michael W. Strickler.

10.27(e)First Amendment to Amended and Restated Employment Agreement, effective as of October 1, 1999, between Mariner Energy, Inc. and Thomas E. Young.

10.28(g)Gas Gathering Agreement, dated December 29, 1999 between MEGS, LLC and Mariner Energy, Inc. and Burlington Resources, Inc.

10.29(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.

23.1** Consent of Ryder Scott Company.

23.2** Ryder Scott Company Letter of Estimated Proved Reserves dated February 23, 2001

27.1** Financial Data Schedule.

(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, 1999, June 30, 1999 or September 30, 1999 quarterly filings on Form 10-Q.

(g) Incorporated by reference to the Mariner Energy Inc. December 31, 2000 annual filing on form 10-K

(b) Reports on Form 8-K:

The Company filed no reports on Form 8-K during the quarter ended December 31, 2000.

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.

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 2, 2000

MARINER ENERGY, INC.

by:/s/ Robert E. Henderson

Robert E. Henderson,
Chairman of the Board, President and 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

Date

Signature	Title	Date
/s/ ROBERT E. HENDERSON Robert E. Henderson	Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)	April 2, 2001
/s/ FRANK A. PICI Frank A. Pici	Vice President of Finance and Chief-Financial Officer (Principal Financial Officer and Principal Accounting Officer)	April 2, 2001
/s/ L. V. MCGUIRE L. V. McGuire	Senior Vice President of Operations and Director	April 2, 2001
/s/ RICHARD R. CLARK Richard R. Clark	Executive Vice President and Director	April 2, 2001
/s/ MICHAEL W. STRICKLER Michael W. Strickler	Senior Vice President of Exploration and Director	April 2, 2001
/s/ RAYMOND M. BOWEN Raymond M. Bowen	Director	April 2, 2001
/s/ RICHARD B.BUY Richard B. Buy	Director	April 2, 2001
/s/ TIMOTHY J. DETMERING	Director	April 2, 2001

Timothy J. Detmering

/s/ JEFFREY M. DONAHUE, JR. --------------------------- Jeffrey M. Donahue, Jr.	Director	April 2, 2001
/s/ CRAIG A. FOX --------------------------- Craig A. Fox	Director	April 2, 2001
/s/ MARK E. HAEDICKE --------------------------- Mark E. Haedicke	Director	April 2, 2001
/s/ JESUS G. MELEDREZ --------------------------- Jesus G. Melendrez	Director	April 2, 2001
/s/ JEFFREY B. SHERRICK --------------------------- Jeffrey B. Sherrick	Director	April 2, 2001

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.