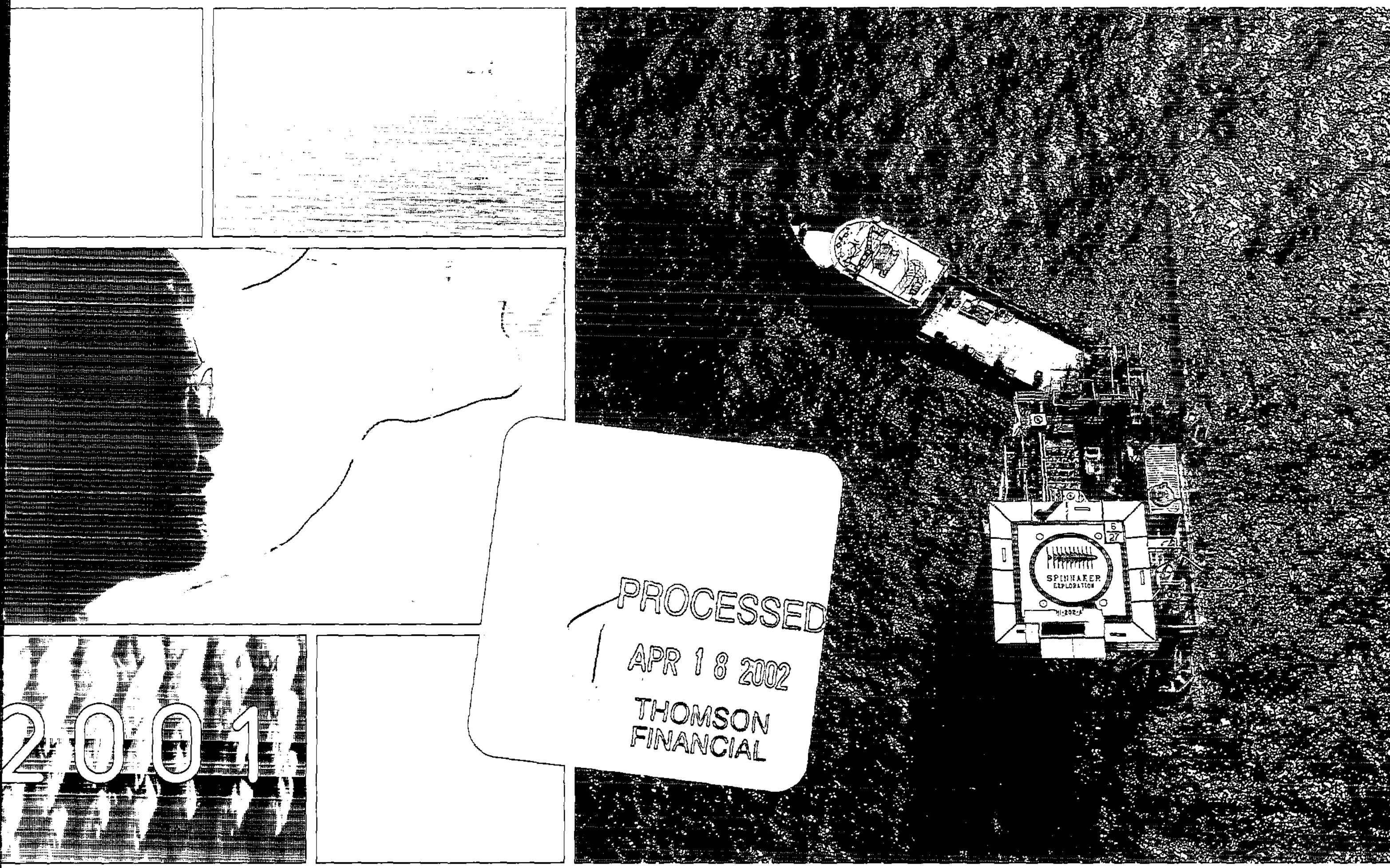

Spinnaker Exploration Annual Report >

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CORPORATE PROFILE > Spinnaker Exploration Company is an independent energy company engaged in the exploration, development and production of natural gas and oil in the U.S. Gulf of Mexico. Formed in December 1996 by its management team and affiliates of E.M. Warburg, Pincus & Co., LLC and Petroleum Geo-Services ASA, Spinnaker became a publicly traded company in September 1999.

Spinnaker's business model focuses on information and technology. The Company has license rights to approximately 11,800 blocks of mostly contiguous, recent vintage 3-D seismic data in the Gulf of Mexico. This database covers an area of approximately 40 million acres, which the Company believes is one of the largest recent vintage 3-D seismic databases of any independent exploration and production company in the Gulf of Mexico. This emphasis on information and technology has translated into success for the Company. From its inception through December 31, 2001, Spinnaker participated in drilling 94 wells, 56 of which were successful. As of December 31, 2001, the Company had estimated proved reserves of 323.2 billion cubic feet of gas equivalent, approximately 54 percent of which was natural gas. The Company has significant operations on the shelf and is continuing to expand its presence in the deep waters of the Gulf of Mexico.

The Company is headquartered in Houston, Texas. Spinnaker's common shares are traded on the New York Stock Exchange under the symbol "SKE."

SPINNAKER EXPLORATION COMPANY

Financial Highlights

(THOUSANDS OF DOLLARS EXCEPT PER SHARE AMOUNTS)

For the Year Ended December 31,	2001	2000	1999
Revenues	$ 210,376	$ 121,383	$ 34,258
Income from operations	100,285	57,264	1,335
Net income [1]	66,226	38,566	671
Basic income per common share [1]	2.45	1.70	0.03
Diluted income per common share [1]	2.34	1.61	0.03
Cash flow from operations [1] [2]	189,209	107,465	23,718
Cash flow from operations per common share [1] [2]	6.67	4.48	1.19
Capital expenditures	288,828	163,739	85,101

As of December 31,	2001	2000	1999
Cash and cash equivalents	$ 14,061	$ 63,910	$ 20,452
Short-term investments	–	22,387	–
Total assets	587,316	442,704	189,553
Equity	458,492	361,259	177,102

SPINNAKER EXPLORATION COMPANY

Operating Highlights

	2001	2000	1999
Production (MMcfe)	53,094	30,194	13,044
Percent natural gas	96%	96%	92%
Average natural gas sales price per Mcf [3]	$ 3.96	$ 4.03	$ 2.57
Average oil and condensate sales price per barrel [3]	$ 24.90	$ 22.98	$ 19.76
Proved reserves (MMcfe)	323,207	182,688	104,501
Percent natural gas	54%	90%	86%
Present value of future net cash flows (before income taxes) discounted at 10 percent (in thousands) [4]	$ 415,139	$1,320,672	$ 151,564
Lease acreage (net acres, in thousands)	629	337	189

[1] Pro forma results in 1999

[2] Before working capital changes

[3] Including the effects of hedging activities

[4] Calculated using weighted average market prices of $2.71, $9.99 and $2.37 per Mcf of natural gas and $19.23, $30.41 and $25.70 per barrel of oil in 2001, 2000 and 1999, respectively

TO OUR SHAREHOLDERS,

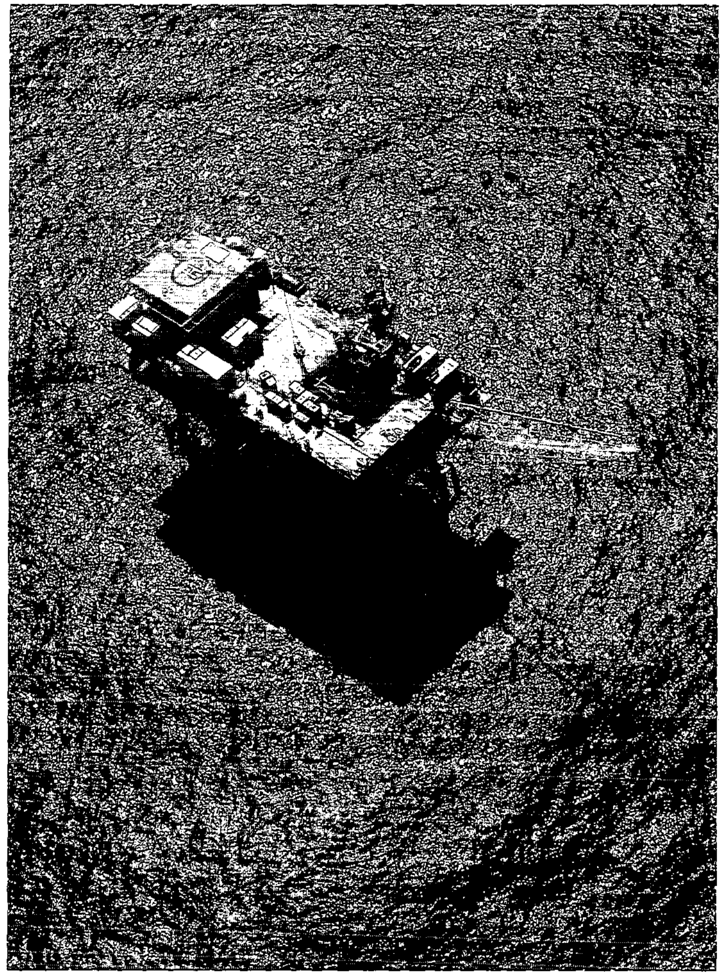
It is a pleasure to report Spinnaker's results for 2001. We hope that our progress meets your expectations.

The Company's production and reserves grew through exploration at industry-leading rates. Our financial margins were among the very best in the industry and our operating cost structure continued to be one of the lowest among public exploration and production companies. During 2001, Spinnaker made nineteen new discoveries in the Gulf of Mexico. At the same time, untested inventory was improved and enlarged. The Company established itself as the dominant deep shelf explorer and the most successful player of its size in the deep water of the Gulf of Mexico. In December 2001, Spinnaker became the best-positioned smaller company in the Eastern Gulf of Mexico.

It should come as considerable comfort to you as a shareholder that these achievements have occurred as the latest progression in the Spinnaker story, and in a year when we simply experienced our share of success and failure. What has been established is that a well-prepared company with substantial technical content can explore for a living and can do so with high financial margins. The fact that exploration can be lumpy is acknowledged. Timing is sometimes less predictable than we would choose. However, high quality exploration with adequate program size can consistently create value. We believe that this will continue to be the case at Spinnaker.

We have added clarity to our strategic positioning and to our medium and long-term commitment to exploration plays that offer significant field size potential. This is not new but we have made excellent progress.

Spinnaker is now the most active and successful explorer of the deep stratigraphic section on the shelf of the Gulf of Mexico. We

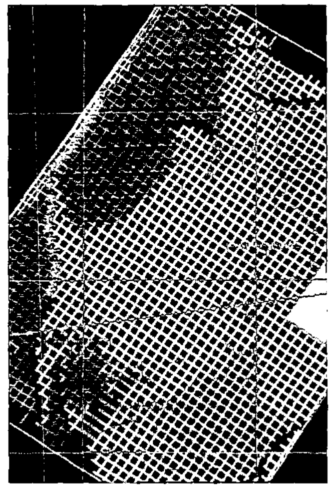


own in excess of 400,000 net acres on prospects that we have generated. We have drilled as many wells and more discoveries than any other explorer in this play since 1998. We have spent a lot of energy and money in the refinement of our play concepts, technologies, technical criteria and drilling practices. There is much that we do not know yet, but we believe that we are well advanced when compared to most of the industry.

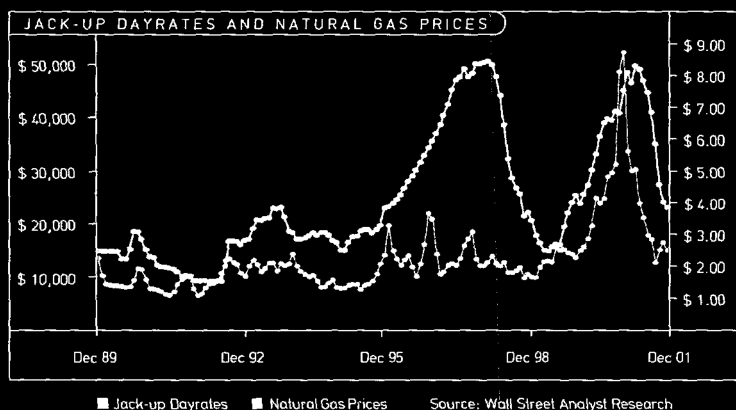
The deep shelf is demanding. Dry hole costs of $10 million or more are not uncommon. In fact, the drilling challenges in this play may be the most intense in the entire Gulf, regardless of water depth. While big fields have been and are being found, smaller ones are frequently discovered instead. Cost structure is critical to long-term success. These dynamics necessitate long-term commitment to the play coupled with adequate program size. We drilled 12 deep shelf wells during 2001 and expect to drill between 12 and 15 in 2002. Today's moderate-cost environment makes it timely to explore in this rewarding play. Spinnaker added at least two significant new fields to the play during 2001; Resolute Field (High Island 197 and 175) and the Stirrup Field (Mustang Island 861).

We also made great progress in deep water during 2001. The Company drilled and/or announced four new field discoveries in deep water during the year; Front Runner, Front Runner South, Seventeen Hands and Callisto. Additionally, development progressed on our 100% owned subsea tieback at Sangria and probable field size was determined at the Zia project.

Once again, these outcomes were the product of methodical efforts by our very talented exploration and production team. While one doesn't find a Front Runner field everyday, I believe that we will find other large fields in the future. I am also certain that we



WE BELIEVE THAT MAINTAINING CONTINUITY IN OUR EXPLORATION ACTIVITIES DURING ALL PHASES OF COMMODITY PRICE CYCLES IS IMPORTANT FOR A BALANCED AND DIVERSIFIED EXPLORATION EFFORT. WE HAVE POSITIONED OURSELVES TO TAKE ADVANTAGE OF LOWER DRILLING AND OTHER OILFIELD SERVICE COSTS DURING PERIODS OF LOW COMMODITY PRICES.

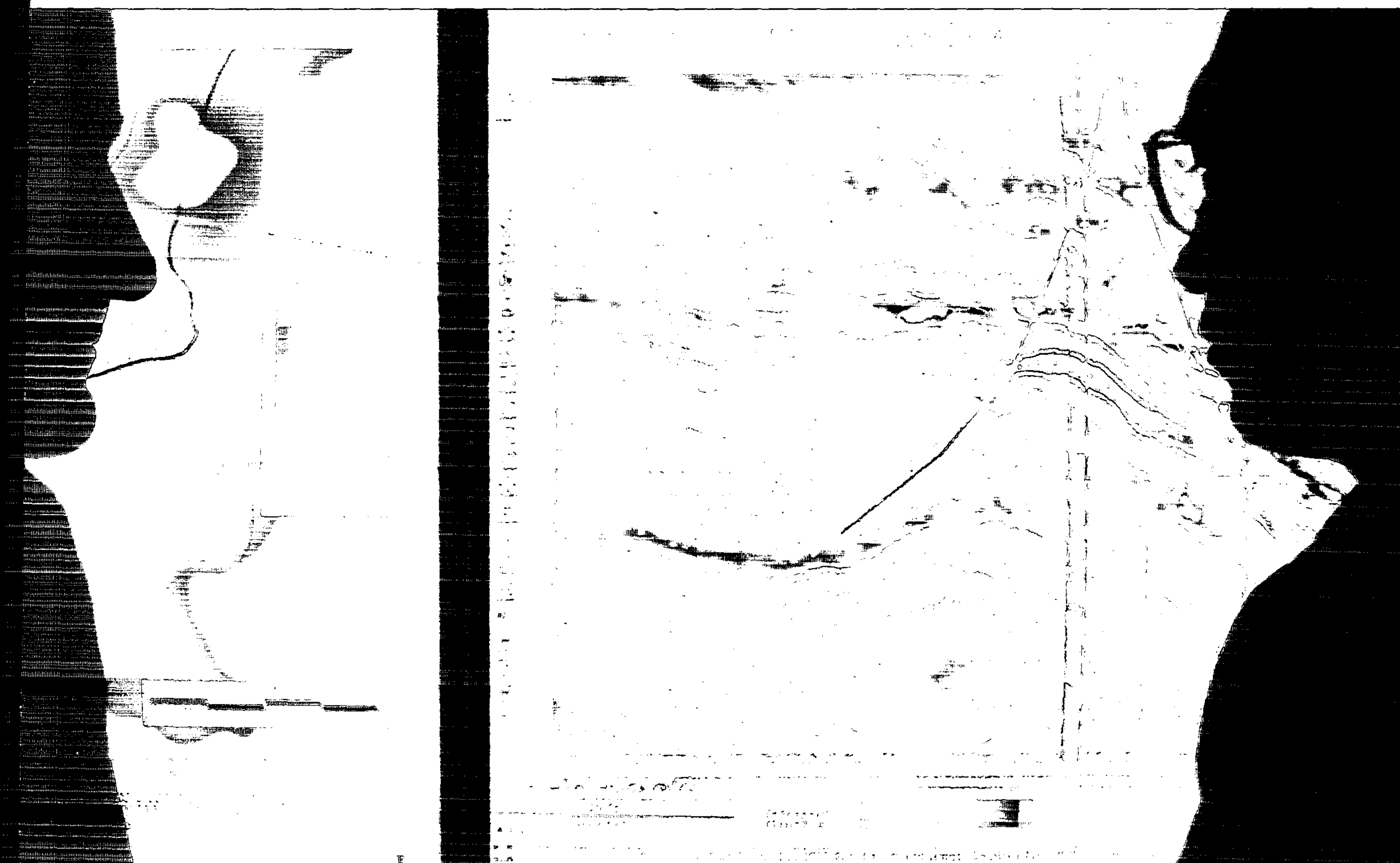


will drill some dry holes along the way. The key is the broad and consistent exposure to high quality prospect concepts. Spinnaker does this exceptionally well.

The Front Runner and Front Runner South Fields could each be world-class, 100+ million barrel oil fields. We own, along with our partners, a total of 17 blocks in the immediate Front Runner area covering 98,000 acres. Spinnaker owns a 25% interest in Front Runner, Front Runner South and a total of 15 blocks in the area. The Company also owns a 50% interest in and operates two blocks in the area. In total, at least ten untested prospects exist on our acreage. While individually, each of these prospects carries risk, we are excited about this new core area and the potential it represents for a company of our size. In addition to this prolific area, Spinnaker owns an interest in five other deep water discoveries and many good deep water prospects. We hold an interest in a total of 89 deep water blocks representing more than 500,000 gross acres. We are well positioned to continue our success in the deep waters of the Gulf.

In December, Spinnaker became the best positioned small to mid-sized independent in the Eastern Gulf of Mexico. OCS Federal Lease Sale #181 took place after considerable deliberation by government and over opposition, primarily from the State of Florida. Spinnaker and its partners were well prepared for the offerings and won two of our three top prospects. We are hopeful that exploration can proceed during 2003.

Together, Spinnaker's dominant positioning on the deep shelf, major success and positioning in deep water, and key holdings in the Eastern Gulf constitute a portfolio that is one of the very best in the Gulf of Mexico – for any company of any size. We sense, as well, that we are capable of meeting the inevitable challenges that we will face in the future.



We will always need to be mindful of how we allocate capital because we have never been opportunity constrained. The size of the financial task that comes with success in these major plays does not escape us. We will allow our balance sheet to grow appropriately to keep our leverage low and to preserve our risk-tolerant culture as we continue to grow.

Many of you know us fairly well and to the extent that you do, you know how important our people are to this successful formula. One of those individuals is Bill Hubbard, our Vice President of Exploration. You've heard me characterize him as "an absolute icon in the business," and the description is accurate. Bill has decided to retire at the end of 2003. We will find him difficult to replace and although his departure is some time away, we are thinking about it now.

During 2001, Spinnaker experienced record production, revenues, cash flow and operating income. It was another great year by any measurable standard. While the commodity outlook is less certain than it was one year ago, Spinnaker is positioned to prosper regardless. We want you to know that we realize that our successes are directly related to, and made possible by, your consistent support.

From the 56 of us who have the privilege of working here each day, we offer our thanks. We will continue to do the very best job that we can for you.

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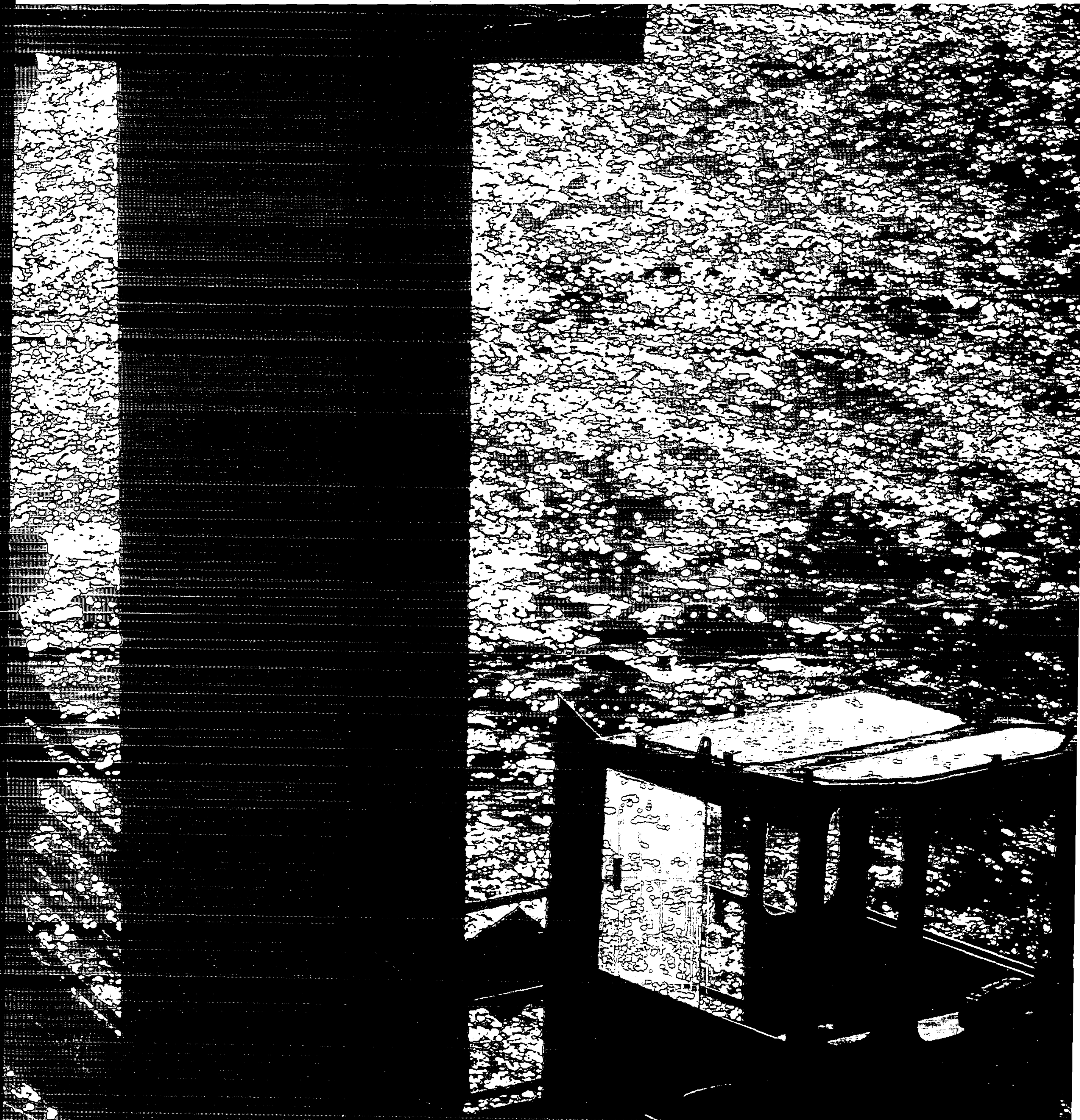
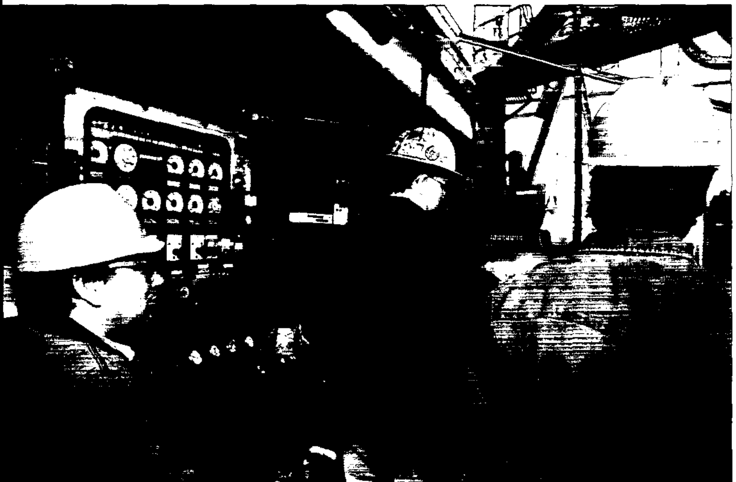
ROGER L. JARVIS

Chairman of the Board, President and Chief Executive Officer

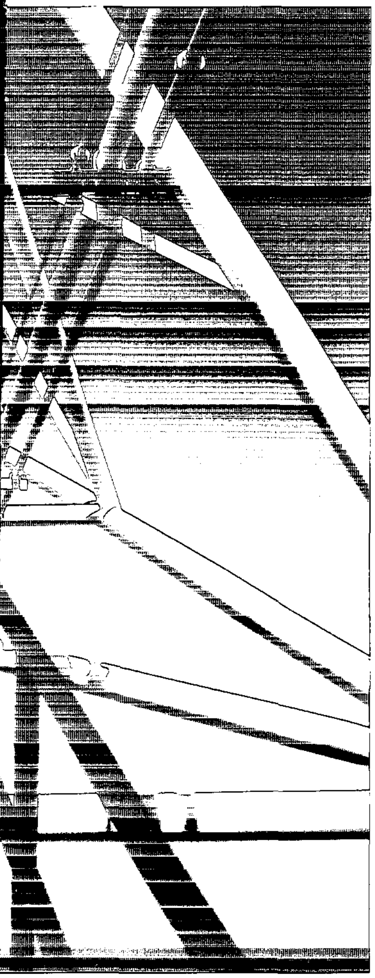




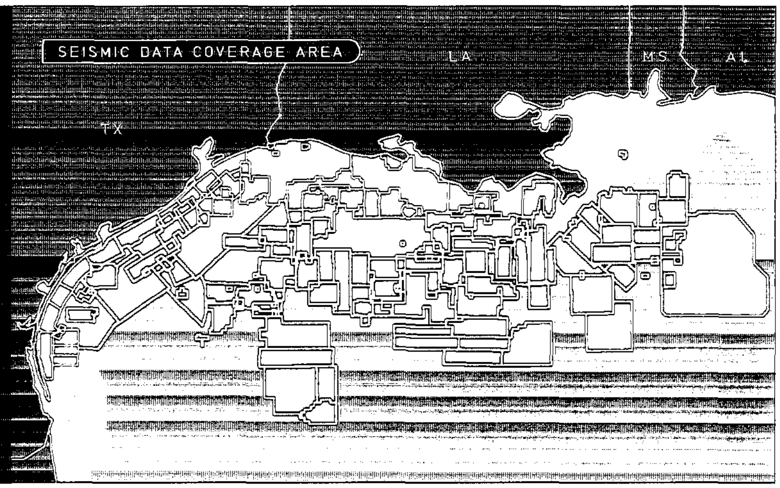
In an industry that has struggled in recent years to generate adequate and constant returns on the capital required for growth, Spinnaker was conceived with a vision that an information advantage would result in a superior business model. This information advantage manifests itself in several ways. It starts with the dataset – 1,400 blocks at inception in early 1997, approximately 11,800 blocks of original and reprocessed data currently. However, the data alone is not sufficient. Mindset and culture are also key components. When acquired broadly, seismic allows for a view in regional context. Add downhole well control to the analysis, performed on all of the acreage in a trend, including non-Spinnaker-owned properties, and the picture becomes clearer.

From there, technology plays a key role in the further illumination and differentiation of underlying geology. The product of this effort is a massive volume of information and the advantage is two-fold. A greatly increased number of prospects provides us with the ongoing ability to constantly high grade them and a better understanding of the individual risks associated with each one. Understanding and sequencing risk properly is also a crucial element of our vision and essential to what we do.

Together, our information advantage and our focus on deep shelf and deep water exploration have generated unprecedented production and reserve growth rates in the Gulf of Mexico over the past five years. Our production has grown to 53.1 Bcfe in 2001 from 0.1 Bcfe in 1997. Our oil and gas reserves were 323.2 Bcfe at the end of 2001 compared to 13.4 Bcfe at the end of 1997. With our commitment to technology and access to the superior dataset



BEGINNING WITH 1,400 BLOCKS OF DATA IN EARLY 1997, WE CURRENTLY HAVE LICENSE RIGHTS TO APPROXIMATELY 11,800 BLOCKS OF MOSTLY CONTIGUOUS, RECENT VINTAGE 3-D SEISMIC DATA IN THE GULF OF MEXICO. THIS DATABASE OF BOTH ORIGINAL AND REPROCESSED DATA COVERS AN AREA OF APPROXIMATELY 40 MILLION ACRES.

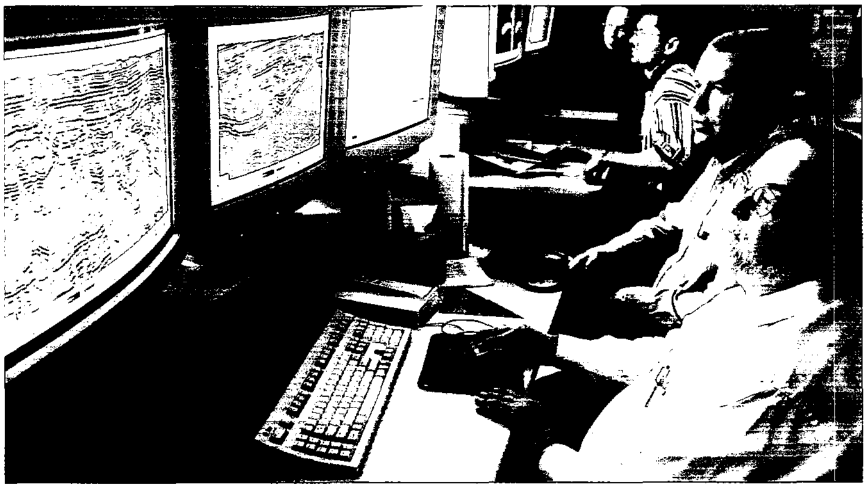


that exists at Spinnaker, we have created an environment that is truly unique. This combination of technology and our focus on exploration accelerates our activity level and produces quality outcomes that translate into significant value for stockholders.

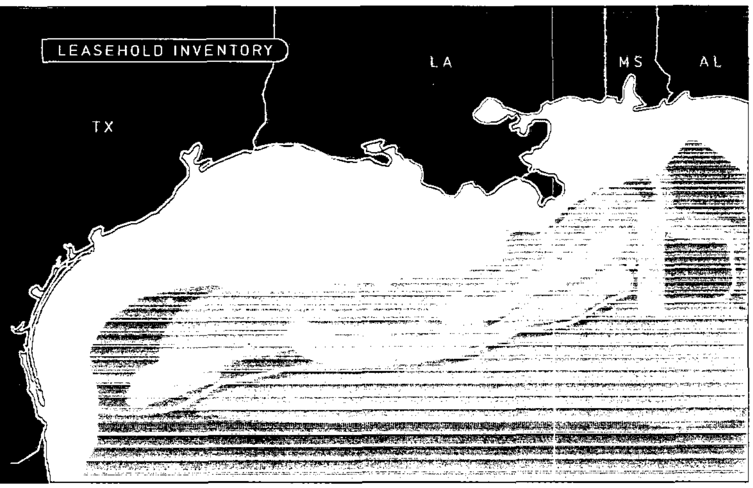
TECHNOLOGY SEQUENCE

Seismic data becomes valuable decision-making information when viewed and evaluated by our exploration specialists using sophisticated modeling and analytical tools. With large geographical datasets we are able to deduce the best new prospects in unexplored areas by drawing comparisons between them and existing wells in other locations. After identifying shared regional features, we further refine the local prospect information so that it provides additional details about subsurface features and characteristics that might otherwise conceal favorable environments.

Our recently completed visualization center contains a high-resolution, large screen image projection system that works with more powerful processing hardware and software than was previously available. Large screen, immersive image environments of this type have been proven to be beneficial for seismic data interpretation because they provide improved pattern recognition within either still frame or motion mode. The result is a state-of-the-art, collaborative environment that allows multi-discipline teams to scan huge volumes of data, isolate patterns indicative of hydrocarbon-bearing formations, correlate them to known producing reservoirs, and then plan for their exploitation in a seamless, efficient process.



AT YEAR-END 2001, WE HELD 284 LEASEHOLD INTERESTS, INCLUDING 88 LEASES IN DEEP WATER. IN THE LAST YEAR, WE ADDED TEN LEASES AROUND OUR SIGNIFICANT DEEP WATER OIL DISCOVERY AT FRONT RUNNER AS WELL AS NUMEROUS LEASES IN THE HIGH ISLAND AREA WHERE WE HAVE EXPERIENCED HIGH EXPLORATION SUCCESS RATES AND EXCELLENT PRODUCTION RESULTS.

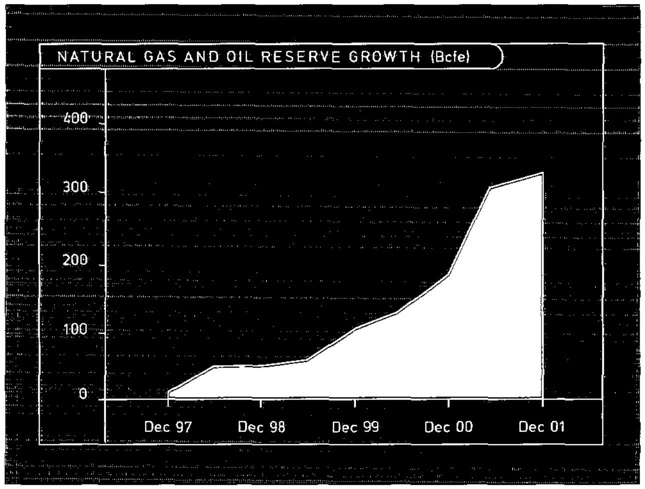


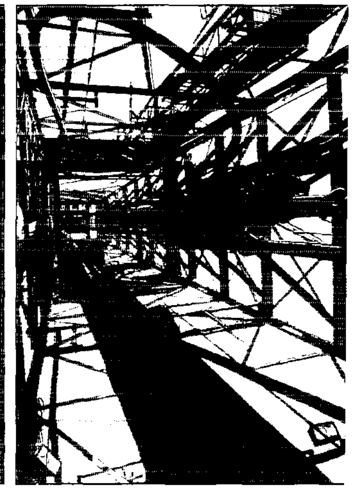
EXPLORATION YIELDS GROWTH

3-D Seismic Data > Spinnaker owns one of the largest recent vintage 3-D seismic databases in the Gulf of Mexico. We consider these massive data volumes, sophisticated imaging techniques and advanced systems technology all necessary to succeed in a meaningful way in the Gulf's frontier plays. Our broad database of 3-D seismic has been a key driver of our rapid growth and our low cost structure. We currently own license rights to approximately 11,800 blocks of data, an increase of 2,300 blocks since year-end 2000.

Leasehold > At the end of 2001, Spinnaker held 284 leasehold interests in the Gulf, including 196 on the shelf and 88 in deep water. Our leasehold has grown methodically from our inception and we anticipate that the number of leasehold interests will increase again during 2002. With a portfolio approach to risk and play types, our information advantage has allowed us to continually add to our inventory of prospects. During 2003, Spinnaker will face certain lease expirations. Although minimal, lease expirations are an ongoing function of the constant high-grading process.

We have never acquired a producing property, so lease sales and the opportunities that come with them are the lifeblood of our company. This year our participation at several Minerals Management Service lease sales bore significant fruit. In the Central Gulf lease sale in March, Spinnaker and our partners were pleased to acquire ten blocks around our significant early 2001 deep water discovery, Front Runner. In August, the Western Gulf lease sale resulted in 32 successful bids, 22 of which are in the Rob trend in





the High Island and Galveston areas where we have been successful in drilling 19 of 26 wells.

In December 2001, the first lease sale since 1988 was conducted for the Eastern Gulf. Although we were the smallest company to participate in this sale, we were awarded, along with our partners, leases on eight blocks that included two of our top three prospects. Our net exposure was only $3.4 million. Leases awarded in the Eastern Gulf lease sale were the result of a two-year effort on our part and provide inventory for the 2003 drilling program and beyond – all in an area that has experienced minimal exploratory drilling over its life. Spinnaker owns a 20% to 33% working interest in this area.

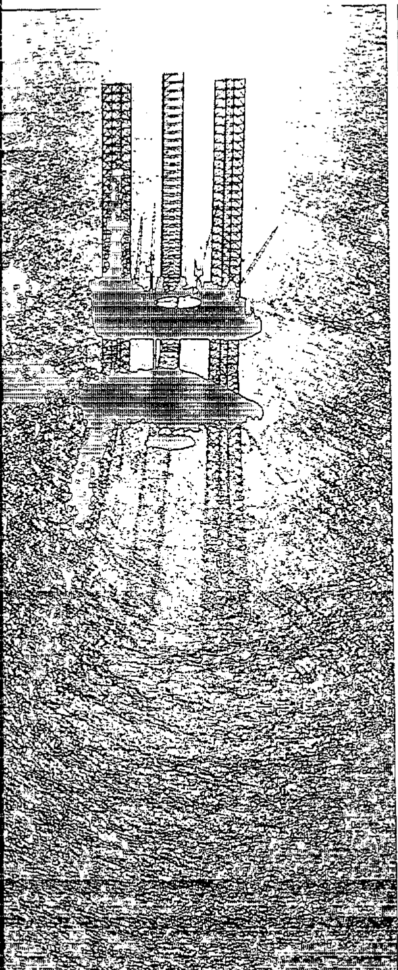
Drilling Results > Spinnaker experienced significantly higher activity levels during 2001. We decisioned 35 wells and defined 19 new discoveries compared to 16 new discoveries in 2000. Since inception, we have drilled 58 successful wells in 97 attempts, resulting in a success rate of 60% (61% in net well terms). While we are certainly a leader in terms of exploratory success rates, we have found high quality assets as well.

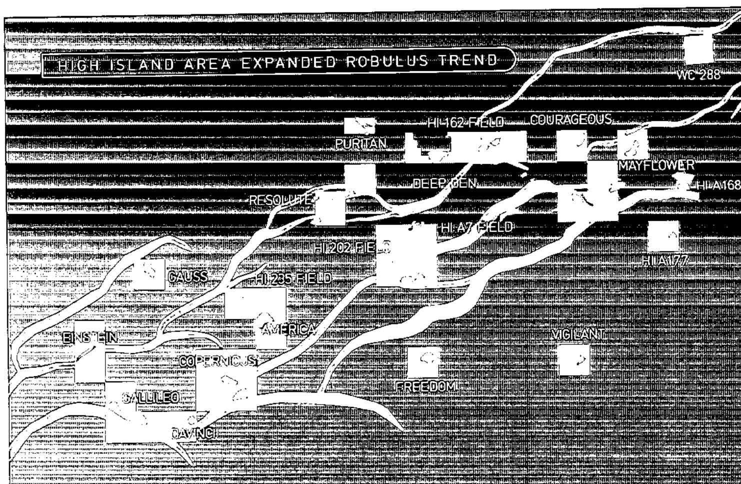
Natural Gas and Oil Reserves > Proved natural gas and oil reserves at the end of 2001 totaled 323.2 Bcfe compared to 182.7 Bcfe at the end of 2000. In 2001, our reserve additions totaled 193.6 Bcfe or 106% of our reserves at the beginning of the year. Reserves grew 77% after production and reserve replacement was 365%.

EXPLORING THE DEEP SHELF

Spinnaker is the Gulf of Mexico's most active deep shelf player. Few companies are currently active in the deep shelf, not only due to drilling and production technology barriers and significant cost requirements, but also because deeper sub-tier features are much more difficult to image. All of these aspects create opportunity for Spinnaker. Of all the wells drilled in the Gulf of Mexico since 1960, 10% have been drilled at depths deeper than 15,000 feet and 3% deeper than 17,000 feet. Although imaging techniques and other technology for deep shelf plays are still evolving, we have defined four dominant deep shelf trends in the past four years. Data, technology and experience merged in the proper environment have generated economic success. Spinnaker is one of a few independents that possess this mindset in combination with the tool kit necessary to succeed in the Gulf's deep shelf frontier plays.

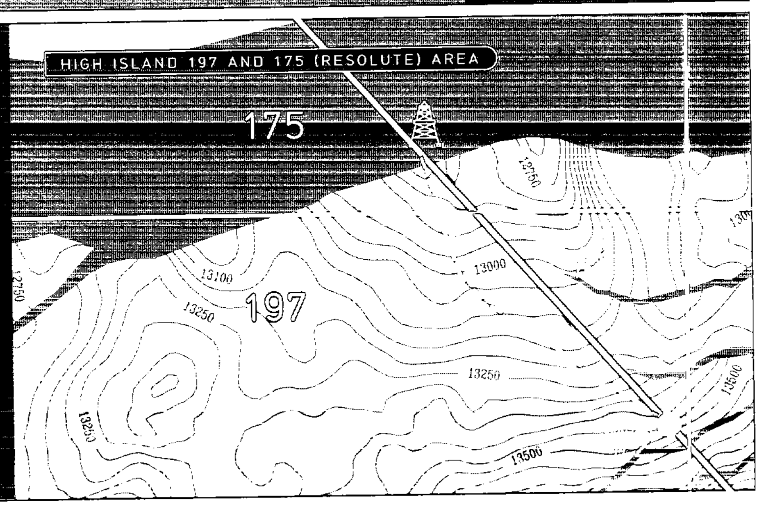
We believe that the Gulf of Mexico, long one of the world's most productive oil and gas provinces, has many significant deep shelf plays that have not been explored. Our deep shelf business has never been more important to the Company than it is now. The Gulf's extensive production, gathering and transmission infrastructure and the resulting immediate access to current gas markets combined with our low cost structure should continue to provide substantial cash flow with which we can fund continued growth.





THE HIGH ISLAND AREA HAS BEEN THE FOUNDATION FOR OUR PRODUCTION GROWTH SINCE 1999. WE HAVE 50 UNDRILLED PROSPECTS ON OUR 45 BLOCK LEASE POSITION AND CONTINUE TO FIND AND UPGRADE PROSPECT LEADS IN THE AREA THAT ARE LIKELY TO RESULT IN ADDITIONAL DRILLING.

OUR LATEST SIGNIFICANT DISCOVERY IN THE HIGH ISLAND AREA IS RESOLUTE. WE OPERATE THIS FIELD WITH A 50% WORKING INTEREST AND PLAN TO DRILL THREE TO FIVE ADDITIONAL WELLS DURING 2002 IN THIS AREA TO TEST THE ENTIRE SEQUENCE OF ROBULUS SANDS. WE EXPECT PRODUCTION TO COMMENCE FROM THIS NEW FIELD BY MID-YEAR 2002.

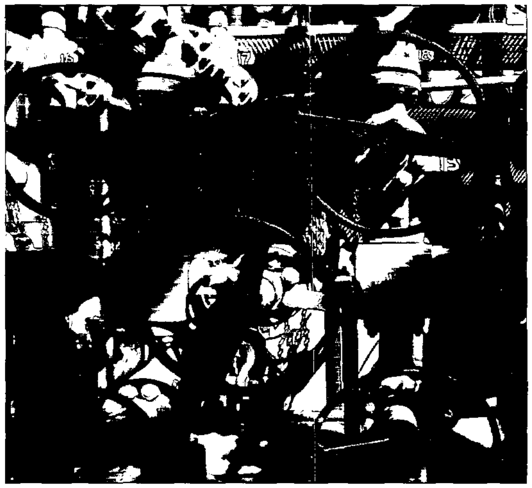


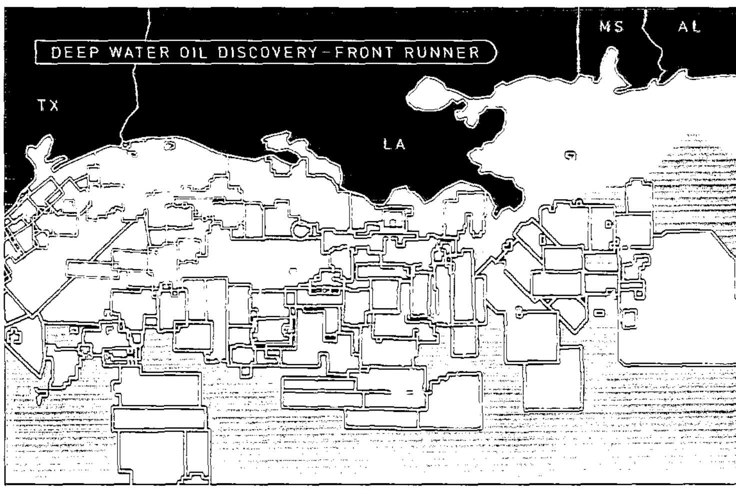
MAJOR DISCOVERIES

High Island Area > The High Island area provides an example of our ability to quickly and broadly leverage new drilling information to create multiple drilling targets. Our initial success in 1998 has subsequently led to 15 additional successful exploratory wells and numerous other prospects in the area. With the knowledge gained from the first well, we have assembled a 45 block lease position covering 245,000 gross acres and have 50 undrilled prospects. We continue to find and upgrade prospect leads in the High Island area that are likely to result in additional drilling.

The High Island 197 (Resolute) exploratory well is our latest significant discovery. We plan to drill three to five additional wells in this area during 2002 to test the entire sequence of Rob sands. Production should commence from this new field by mid-year 2002. We are operators of the field with a 50% working interest and a 42% net revenue interest.

Alex Deep Field > In partnership with a major oil company, we drilled the original well in Brazos A-19 in early 1998 and by late 1999, the well flowed at a daily rate in excess of 90 MMcf prior to experiencing major mechanical problems. Subsequently plugged and abandoned, its replacement well was drilled to total depth, evaluated and cased successfully in 2001. The well encountered productive intervals similar to the original well. We expect production to commence mid-year 2002. We own a 15% working interest and 12.5% net revenue interest in the Alex Deep well. This discovery is an example of how information and the technology unlock ideas. The Alex Deep well is in the middle of the Corsair trend, an area discovered by our major partner in the 1970s that





IN 2001, WE PARTICIPATED IN A SIGNIFICANT DEEP WATER OIL DISCOVERY ON GREEN CANYON BLOCKS 338/339 (FRONT RUNNER) THAT HAS CHANGED OUR RESERVE PROFILE. PROVED OIL RESERVES WERE 46% OF TOTAL PROVED RESERVES AT DECEMBER 31, 2001 COMPARED TO 10% AT DECEMBER 31, 2000.

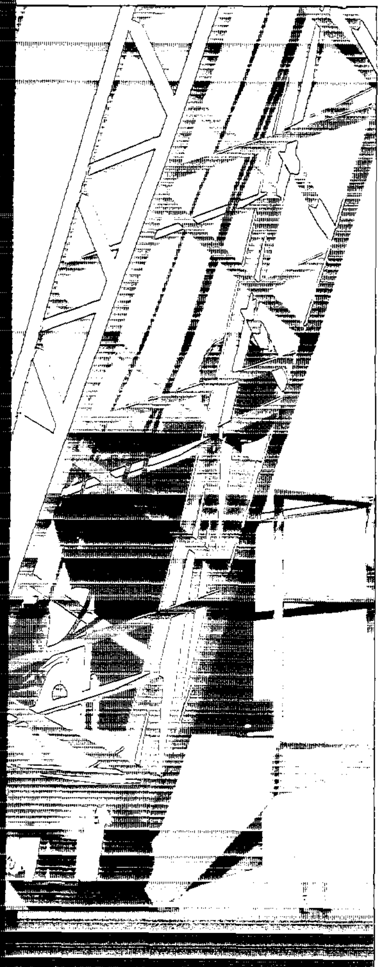
historically produced only from shallower horizons. Although heavily evaluated for two decades, the area's deep shelf potential was only recently brought to light with this 100+ Bcf discovery.

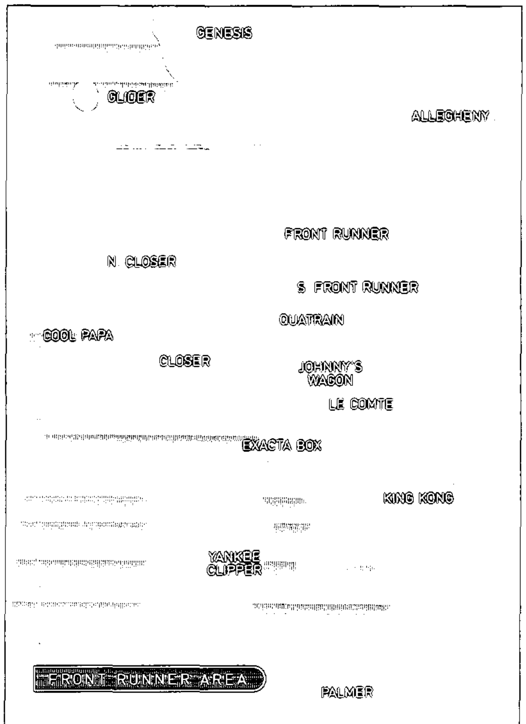
Comparison of 2002/2001 Deep Shelf Programs > We plan to drill another ten to twelve wells in the High Island area during 2002. Our expanding database will continue to yield opportunities, while the existing prospect base will be further explored. We plan to enhance our position in a number of existing plays as well as enter new areas. Our prospects for growth in the deep shelf have never been so strong or exciting.

Success in the Deep Water > Generally, only the largest exploration and production companies are consistently active in the deep waters of the Gulf. Deep shelf and deep water exploration share many of the same barriers to entry including drilling and production technology, significant costs and expenses, in addition to long lead times. A strong balance sheet and access to capital are vital requirements for successful participation in this capital intensive area. We have been successful in the deep waters of the Gulf despite being a younger and smaller company than the typical deep water player, and in 2001 we successfully transitioned a portion of our exploration efforts from the shelf to the deep water. In the last year alone, we participated in seven successful deep water wells. Over the prior three-year period, we participated in only three successful deep water wells.

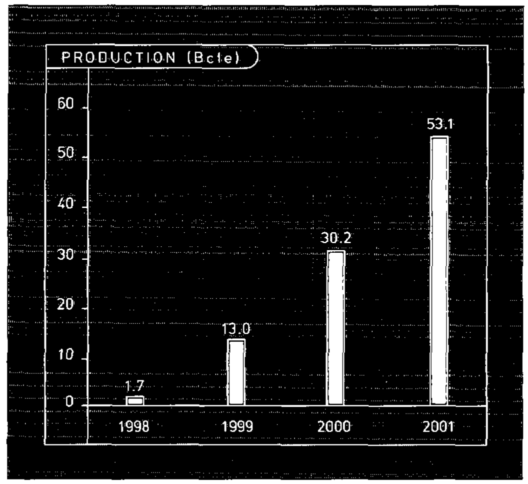
MAJOR DISCOVERIES

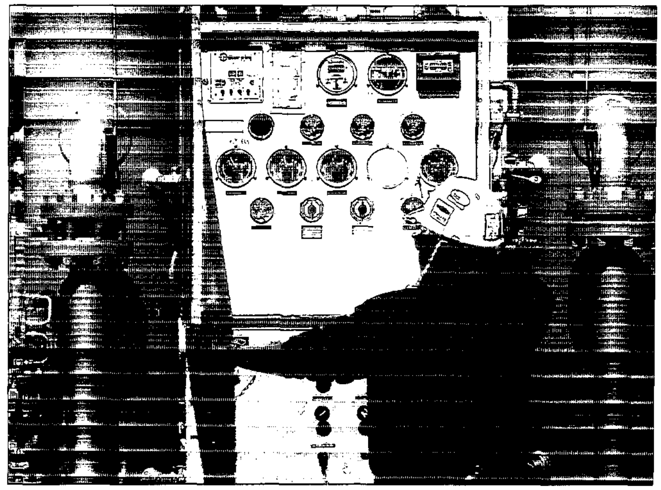
Front Runner Area > The Green Canyon 338/339 (Front Runner) area is one of our most exciting exploratory areas. To date, we have participated in five consecutive discoveries in the area,





THE FRONT RUNNER AREA IS ONE OF OUR MOST EXCITING EXPLORATORY AREAS. WE HAVE IDENTIFIED TEN UNDRILLED PROSPECTS IN OUR 17 BLOCK LEASE POSITION COVERING 98,000 GROSS ACRES. WE OWN A 25% TO 50% WORKING INTEREST IN THE FRONT RUNNER AREA BLOCKS AND PLAN TO TEST THREE-TO-FIVE NEW PROSPECTS IN THE AREA DURING 2002.



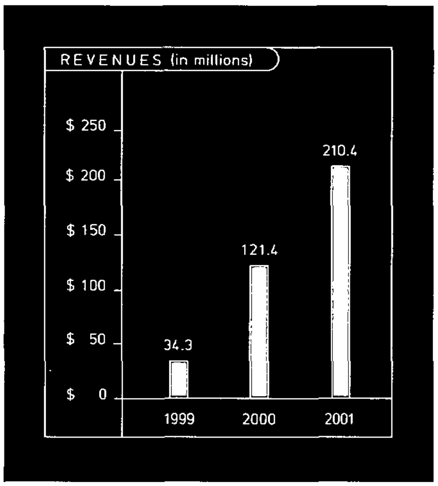


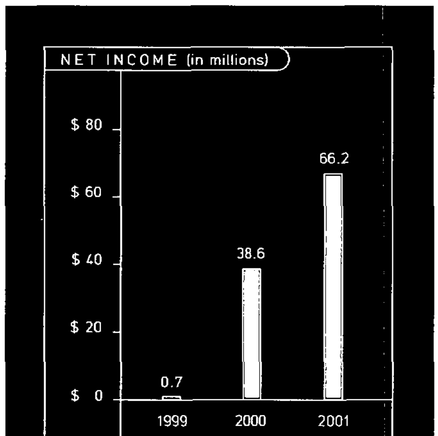
assembled a 17 block lease position covering 98,000 gross acres, and have identified ten undrilled prospects. Spinnaker owns a 25% to 50% working interest and net revenue interest in the Front Runner area. These working interests are subject to royalty of 12.5% after production of 87.5 million equivalent barrels of oil, on a block-by-block and field-by-field basis. Along with our partners, we have sanctioned a spar production platform for this discovery.

Comparison of 2002 / 2001 Deep Water Programs > The Company plans to test three to five prospects in the Front Runner area in 2002. Although not without risk, our prospects for growth in deep water are very encouraging. In addition to Front Runner, our efforts in the deep water continue to expand with three wildcats planned in other areas of the Gulf in 2002.

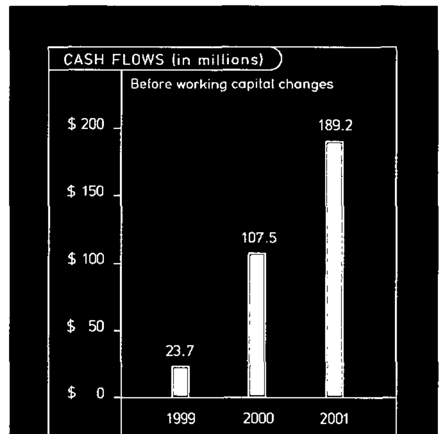
PRODUCTION

Production increased 76% to 53.1 Bcfe in 2001 from 30.2 Bcfe in 2000. As our exploration efforts have discovered excellent assets, our drilling and production group has delivered timely and creative development solutions. This combination has allowed us to bring fields on-line quickly and economically. We believe that our quality of operation, including cost control, is equal in importance to our exploration process. As a result, we are one of the Gulf's lowest unit cost producers among publicly-traded companies. Front Runner will take another two years to come on-line, but we feel confident 2004 production will be positively impacted in a material manner. The additional prospects in the Front Runner area give us reason for optimism beyond 2004.





(Pro forma results in 1999)



(Pro forma results in 1999)

ANOTHER OUTSTANDING YEAR

Our financial performance in 2001 was the direct result of significant production gains, contributions from higher average commodity prices and continued operating efficiencies. We have never purchased oil and gas reserves or production. Instead, our focus on exploration to fuel growth has translated to high margins and superior returns.

Revenues increased $89.0 million, or 73%, to $210.4 million in 2001. Net income increased $27.7 million, or 72%, to $66.2 million in 2001. Cash flow from operations increased $81.7 million, or 76%, to $189.2 million in 2001. Spinnaker ended the year with no debt and $14.1 million in cash and cash equivalents. Going forward, while we anticipate carrying some debt in 2002, we plan to continue the strategy of financing ourselves cautiously so our stockholders may benefit throughout the business cycle.

LOOKING FORWARD

We expect our information advantage and focus on deep shelf and deep water exploration to continue to yield new opportunities for our company and our shareholders. Our position in a number of existing plays will continue to be enhanced and we plan to enter new areas in the deep water. With a capital budget of $250 million, we plan to drill 35 wells during 2002, including 28 on the shelf and seven in deep water. While this number is down from our spending last year, our activity level remains the same. We are well-positioned to take advantage of market downcycles in which service company costs are reduced. Accordingly, we are taking advantage of the current cost structure to drill higher risk, higher potential wells at significantly less cost than a year ago. We are optimistic that Spinnaker will continue to grow at above average rates and look forward to a successful 2002.

Cautionary Statement About Forward-Looking Statements

Some of the information in this annual report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. The forward-looking statements speak only as of the date made, and the Company undertakes no obligation to update such forward-looking statements. These forward-looking statements may be identified by the use of the words "believe," "expect," "anticipate," "will," "contemplate," "would" and similar expressions that contemplate future events. These future events include the following matters:

- financial position;
- business strategy;
- budgets;
- amount, nature and timing of capital expenditures, including future development costs;
- drilling of wells;
- natural gas and oil reserves;
- timing and amount of future production of natural gas and oil;
- operating costs and other expenses;
- cash flow and anticipated liquidity;
- prospect development and property acquisitions; and
- marketing of natural gas and oil.

Numerous important factors, risks and uncertainties may affect the Company's operating results, including:

- the risks associated with exploration;
- the ability to find, acquire, market, develop and produce new properties;
- natural gas and oil price volatility;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;
- operating hazards attendant to the natural gas and oil business;
- downhole drilling and completion risks that are generally not recoverable from third parties or insurance;
- potential mechanical failure or under-performance of significant wells;
- climatic conditions;
- availability and cost of material and equipment;
- delays in anticipated start-up dates;
- actions or inactions of third-party operators of the Company's properties;
- the ability to find and retain skilled personnel;
- availability of capital;
- the strength and financial resources of competitors;
- regulatory developments;
- environmental risks; and
- general economic conditions.

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

Management's Discussion and Analysis of Financial Condition and Results of Operations

OVERVIEW

The Company experienced significant growth rates in both production and reserves in 2001. Performance highlights in 2001 compared to 2000 included record:

- Production of 53.1 Bcfe, up 76 percent.
- Proved reserves of 323.2 Bcfe, up 77 percent after production; reserve replacement was 365 percent of production.
- Revenues of $210.4 million, up 73 percent.
- Income from operations of $100.3 million, up 75 percent.
- Net income of $66.2 million, or $2.34 per diluted share, up 72 percent.
- Cash flows from operating activities, before working capital changes, of $189.2 million, up 76 percent.

Spinnaker's results of operations and financial position were significantly impacted by natural gas production and prices in 2001. Natural gas revenues increased $79.0 million. Natural gas production volumes increased 22.4 Bcf, contributing $123.9 million of the increase in natural gas revenues, excluding the effects of hedging activities, offset in part by $44.9 million related to lower average natural gas prices in 2001 compared to 2000. The Company had $14.1 million in cash and cash equivalents and no debt at December 31, 2001.

In addition, Spinnaker participated in a significant deep water oil discovery in 2001 on Green Canyon Blocks 338/339 (Front Runner) with a 25 percent non-operator working interest. The Company participated in five consecutive successful wells and sidetracks in testing the reservoirs on these blocks. This significant oil discovery has changed Spinnaker's reserve profile. Proved oil and condensate reserves were 46 percent of total proved reserves at December 31, 2001 compared to 10 percent at December 31, 2000. Of the Company's total proved reserves as of December 31, 2001, 73 percent were proved undeveloped reserves. Front Runner represented more than 50 percent of total proved undeveloped reserves.

RISK FACTORS

In addition to the other information set forth elsewhere in this annual report, the following factors should be carefully considered when evaluating Spinnaker.

Exploration is a high-risk activity, and the 3-D seismic data and other advanced technologies the Company uses cannot eliminate exploration risk and require experienced technical personnel whom the Company may be unable to attract or retain.

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

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

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

Spinnaker's 2001 deep water oil discovery, Front Runner, will require significant financial resources and presents numerous uncertainties. Spinnaker's 2001 deep water oil discovery on Green Canyon Blocks 338/339, Front Runner, in which the Company has a 25% non-operator working interest, has required and will continue to require significant financial resources over the next two years. The Company incurred $30 million in capital expenditures for Front Runner in 2001 and expects to incur an aggregate of $110 million in future development costs during 2002 and 2003. Also, Front Runner accounted for more than 50 percent of proved undeveloped reserves at December 31, 2001.

Another oil and gas company operates Front Runner. As a result, the Company has a limited ability to exercise influence over operations and costs for this property. The Company has limited experience with large deep water and deep drilling depth discoveries similar to Front Runner as most of its prior discoveries have occurred in shallower waters and at shallower drilling depths. Front Runner is located in approximately 3,500 feet of water and the most recent well was drilled to a total depth in excess of 21,700 feet. Although the Company expects to incur approximately $140 million to develop this discovery, its size and scope are much larger than the Company's prior discoveries and the Company may encounter difficulties and delays that could cause actual expenditures to far exceed anticipated amounts. Even if production ultimately commences for this discovery, it may produce substantially less oil and natural gas than currently projected. The Company does not expect this discovery to commence production prior to 2004, but it must commit substantial resources in advance of the expected production date and cannot predict the price of oil if and when production commences. These uncertainties and other risks described in this "Risk Factors" section and elsewhere in this annual report make it difficult to predict whether Front Runner can be successfully or economically developed. If Front Runner cannot be successfully and economically developed, the Company's future business, financial condition and operating results will be materially and adversely affected.

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

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

For some risks, the Company may not obtain insurance if it believes the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect the Company's operations.

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

As part of its strategy, the Company explores for natural gas and oil at deeper drilling depths and in the deep waters of the Gulf of Mexico, where operations are more difficult and costly than at shallower depths and in shallower waters. Deep depth and deep water drilling and operations require the application of recently developed technologies that involve a higher risk of mechanical failure. The Company has experienced and will continue to experience significantly higher drilling costs for its deep depth and deep water prospects. Furthermore, the deep waters of the Gulf of Mexico lack the physical and oilfield service infrastructure present in the shallower waters. As a result, deep water operations may require a significant amount of time between a discovery and the time that the Company can market the natural gas or oil, increasing both the financial and operational risk involved with these operations.

The Company is vulnerable to operational, regulatory and other risks associated with the Gulf of Mexico because it currently explores and produces exclusively in that area.

The Company's operations and revenues are impacted acutely by conditions in the Gulf of Mexico because it currently explores and produces exclusively in that area. This concentration of activity makes the Company more vulnerable than many of its competitors to the risks associated with the Gulf of Mexico, including delays and increased costs relating to adverse weather conditions, drilling rig and other oilfield services and compliance with environmental and other laws and regulations.

During the second half of 2000 and early 2001, higher prices for natural gas and oil led to greater demand for drilling rig and other oilfield services. As a result, the Company experienced increased costs and reduced availability of these services.

A significant part of the value of the Company's production and reserves is concentrated in a small number of offshore properties. Because of this concentration, any production problems or inaccuracies in reserve estimates related to those properties are more likely to adversely impact the Company's business.

During 2001, over 71 percent of the Company's production came from three of its properties in the Gulf of Mexico. If mechanical problems, storms or other events curtailed a substantial portion of this production, the Company's cash flow would be adversely affected. In addition, at December 31, 2001, the Company's proved reserves were located on 30 different blocks in the Gulf of Mexico, with approximately 73 percent of the proved reserves attributable to five of these properties. One property, Front Runner, accounted for more than 50 percent of total proved undeveloped reserves. If the actual reserves associated with any one of these five properties are substantially less than the estimated reserves, the Company's results of operations and financial condition could be adversely affected.

The Company's right to receive data under the Data Agreement will be substantially restricted after March 31, 2002. In addition, if PGS terminates the Data Agreement, the Company's ability to find additional reserves could be impaired.

The Company's success depends heavily on its access to 3-D seismic data, and one of its primary sources for 3-D seismic data is the Data Agreement. The Company is only entitled to receive and use 3-D seismic data that PGS acquires and processes prior to March 31, 2002 or that PGS is in the process of acquiring or processing as of that date. In addition, if PGS terminates the Data Agreement, the Company would lose access to a portion of its 3-D seismic data which loss could have an adverse effect on its ability to find additional reserves. PGS may terminate the Data Agreement on several grounds, including if a PGS competitor acquires control of Spinnaker or if the Company breaches the Data Agreement subject to specified exceptions.

Competitors may use superior technology which the Company may be unable to afford or which would require costly investment in order to compete.

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

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and net present value of the Company's reserves.

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

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

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from the Company's estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, the Company may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond the Company's control. At December 31, 2001, approximately 87 percent of the Company's proved reserves were either proved undeveloped or proved non-producing. Moreover, some of the producing wells included in the reserve report had produced for a relatively short period of time as of December 31, 2001. Because most of the reserve estimates are not based on a lengthy production history and are calculated using volumetric analysis, these estimates are less reliable than estimates based on a lengthy production history.

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

The failure to replace reserves would adversely affect production and cash flows.

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

Relatively short production periods for Gulf of Mexico properties subject the Company to higher reserve replacement needs, require significant capital expenditures to replace production and may impair its ability to reduce production during periods of low natural gas and oil prices.

Production of reserves from reservoirs in the Gulf of Mexico generally declines more rapidly than from reservoirs in many other producing regions of the world. This results in recovery of a relatively higher percentage of reserves from properties in the Gulf of Mexico during the initial few years of production. As a result, reserve replacement needs from new prospects are greater and require the Company to incur significant capital expenditures to replace production. The rapid production declines of certain producing wells, combined with pipeline-mandated curtailments of certain facilities, shut-ins related to facility upgrades and less than anticipated results from workovers, resulted in lower production in the fourth quarter of 2001 compared to the prior quarter. The Company expects a further decline in production during the first quarter of 2002.

Also, revenues and return on capital will depend significantly on prices prevailing during these relatively short production periods. The Company's potential need to generate revenues to fund ongoing capital commitments or reduce indebtedness may limit its ability to slow or shut-in production from producing wells during periods of low prices for natural gas and oil.

Natural gas and oil prices fluctuate widely, and low prices could have a material adverse impact on the Company's business and financial results.

The Company's revenues, profitability and future growth depend substantially on prevailing prices for natural gas and oil. Prices also affect the amount of cash flow available for capital expenditures and the Company's ability to borrow and raise additional capital. The amount the Company can borrow under the Credit Facility is subject to periodic re-determination based in part on changing expectations of future prices. Lower prices may also reduce the amount of natural gas and oil that the Company can economically produce.

Prices for natural gas and oil fluctuate widely. For example, natural gas prices declined significantly in 2001 from levels reached in the second half of 2000 and early 2001. Prices for natural gas and oil also declined significantly in 1998 and, for an extended period of time, remained substantially below prices obtained in previous years. Among the factors that can cause this fluctuation are the level of consumer product demand, weather conditions, domestic and foreign governmental regulations, the price and availability of alternative fuels, political conditions in natural gas and oil producing regions, the domestic and foreign supply of natural gas and oil, the price of foreign imports and overall economic conditions. If natural gas and oil prices decline, even if for only a short period of time, it is possible that write-downs of natural gas and oil properties could occur in the future.

Hedging production has limited and may continue to limit potential gains from increases in commodity prices or result in losses.

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

The Company's success depends on its Chief Executive Officer and other key personnel, the loss of whom could disrupt business operations.
The Company depends to a large extent on the efforts and continued employment of the Company's President and Chief Executive Officer, Roger L. Jarvis, and other key personnel. If Mr. Jarvis or these other key personnel resign or become unable to continue in their present role and if they are not adequately replaced, the Company's business operations could be adversely affected.

The Company is subject to complex laws and regulations, including environmental regulations, that can adversely affect the cost, manner or feasibility of doing business.
Exploration for and development, production and sale of natural gas and oil in the U.S. and especially in the Gulf of Mexico are subject to extensive federal, state and local laws and regulations, including environmental laws and regulations. The Company may be required to make large expenditures to comply with environmental and other governmental regulations. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations and taxation.

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

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

The Company cannot control the activities on properties it does not operate.
Other companies operate some of the properties in which the Company has an interest. As a result, the Company has a limited ability to exercise influence over operations for these properties or their associated costs. The Company's dependence on the operator and other working interest owners for these projects and its limited ability to influence operations and associated costs could materially adversely affect the realization of its targeted returns on capital in drilling or acquisition activities. The success and timing of drilling and development activities on properties operated by others therefore depend upon a number of factors that are outside of the Company's control, including timing and amount of capital expenditures, the operator's expertise and financial resources, approval of other participants in drilling wells and selection of technology.

The Company may have difficulty financing its planned growth.

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

Because the Company has a limited operating history and has incurred losses from operations in the past, future operating results are difficult to forecast. The Company's failure to sustain profitability in the future could adversely affect the market price of Spinnaker's Common Stock.

The Company was formed in December 1996 and, as a result, has a limited operating history. The Company's limited operating history and the unpredictable results of its exploration and development strategy make it difficult to forecast operating results. In considering whether to invest in Spinnaker's Common Stock, the limited historical financial and operating information available on which to base an evaluation of the Company's performance should be considered. In addition, because the Company has a limited operating history and fewer financial resources than many companies in the industry, it may be at a disadvantage in bidding for exploratory prospects and in developing natural gas and oil properties.

The Company incurred net losses of $1.3 million, $6.9 million, $2.2 million and $0.3 million in 1999, 1998, 1997 and 1996, respectively. The Company's development of and participation in a larger number of prospects has required and will continue to require substantial capital expenditures. The Company cannot provide assurance that it will sustain profitability or positive cash flows from operating activities in the future. The Company's failure to sustain profitability in the future could adversely affect the market price of Spinnaker's Common Stock.

Warburg, Pincus Ventures, L.P. ("Warburg") owns a significant amount of Common Stock, giving it influence in corporate transactions and other matters, and the interests of Warburg could differ from those of other stockholders.

At December 31, 2001, Warburg owned approximately 25 percent of the outstanding shares of Common Stock. As a result, Warburg is in a position to significantly influence the outcome of matters requiring a stockholder vote, including the election of directors, the adoption of an amendment to the certificate of incorporation or bylaws and the approval of mergers and other significant corporate transactions. Its influence over Spinnaker may delay or prevent a change of control of the Company and may adversely affect the voting and other rights of other stockholders.

Furthermore, conflicts of interest could arise in the future between the Company and Warburg concerning, among other things, potential competitive business activities or business opportunities. Warburg is not restricted from competitive natural gas and oil exploration and production activities or investments. Warburg currently has significant equity interests in other public and private natural gas and oil companies. The interests of Warburg could differ from those of other stockholders.

A portion of the Company's outstanding shares owned by Warburg or other significant stockholders may be sold into the market in the near future. This could cause the market price of the Common Stock to drop significantly, even if the Company's business is doing well.

The market price of the Common Stock could drop due to sales of a large number of shares of Common Stock in the market or the perception that such sales could occur. This could make it more difficult to raise funds through any future offering of Common Stock.

The certificate of incorporation and bylaws contain provisions that could discourage an acquisition or change of control of the Company.

The certificate of incorporation authorizes the board of directors to issue Preferred Stock without stockholder approval. If the board of directors elects to issue Preferred Stock, it could be more difficult for a third party to acquire control of the Company, even if that change of control might be beneficial to stockholders. In addition, provisions of the certificate of incorporation and bylaws, such as no stockholder action by written consent and limitations on stockholder proposals at meetings of stockholders, could also make it more difficult for a third party to acquire control of the Company.

Terrorist attacks on natural gas and oil production facilities, transportation systems and storage facilities could have a material adverse impact on the Company's business.

Natural gas and oil production facilities, transportation systems and storage facilities could be targets of terrorist attacks. These attacks could have a material adverse impact if certain natural gas and oil infrastructure integral to the Company's operations were destroyed or damaged.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in conformity with accounting principles generally accepted in the United States 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 amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates include depreciation, depletion and amortization ("DD&A") of proved natural gas and oil properties. Natural gas and oil reserve estimates, which are the basis for unit-of-production DD&A and the full cost ceiling test, are inherently imprecise and are expected to change as future information becomes available. The Company's critical accounting policies are as follows:

NATURAL GAS AND OIL PROPERTIES

The Company uses the full cost method of accounting for its investment in natural gas and oil properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of exploring for natural gas and oil are capitalized. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals and costs related to such activities. Exclusive of field-level costs, Spinnaker capitalized $5.1 million, $3.8 million and $2.5 million of general and administrative costs in 2001, 2000 and 1999, respectively. These capitalized costs are directly related to exploration activities and include salaries, employee benefits, costs of consulting services and other related expenses. Costs associated with production and general corporate activities are expensed in the period incurred. Interest costs related to unproved properties and properties under development are also capitalized to natural gas and oil properties. Spinnaker capitalized interest of $0, $17,000 and $966,000 in 2001, 2000 and 1999, respectively. Sales of natural gas and oil properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of natural gas and oil.

The Company computes the provision for DD&A of natural gas and oil properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the amortization base until the properties associated with these costs are evaluated. In addition to costs associated with evaluated properties, the amortization base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values. Certain future development costs may be excluded from amortization when incurred in connection with major development projects expected to entail significant costs to ascertain the quantities of proved reserves attributable to the properties under development. The amounts that may be excluded are applicable portions of the costs that relate to the major development project and have not previously been included in the amortization base and the estimated future expenditures associated with the development project. Such costs may be excluded from costs to be amortized until the earlier determination of whether additional reserves are proved or impairment occurs. The Company has excluded from amortization a portion of the estimated future expenditures associated with common development costs on its deep water discovery at Front Runner based on existing proved reserves to total proved reserves expected to be established upon completion of the deep water project.

Capitalized costs of natural gas and oil properties, net of accumulated DD&A and related deferred taxes, are limited to the estimated future net cash flows from proved natural gas and oil reserves, including the effects of hedging activities, discounted at 10 percent, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (the full cost ceiling). If capitalized costs exceed the full cost ceiling, the excess is charged to write-down of natural gas and oil properties in the quarter in which the excess occurs.

Given the volatility of natural gas and oil prices, it is reasonably possible that the Company's estimate of discounted future net cash flows from proved natural gas and oil reserves will change in the near term. If natural gas and oil prices decline, even if for only a short period of time, or if the Company has downward revisions to its estimated proved reserves, it is possible that write-downs of natural gas and oil properties could occur in the future.

The costs associated with unevaluated leasehold acreage, unamortized seismic data, wells currently drilling and capitalized interest are not initially included in the amortization base. Leasehold costs are either transferred to the amortization base with the costs of drilling the related well or are assessed quarterly for possible impairment or reduction in value. Leasehold costs are transferred to the amortization base if a reduction in value has occurred. Of the $102.9 million of net unproved property costs at December 31, 2001 excluded from the amortizable base, net costs of $19.7 million, $42.5 million and $12.3 million were incurred in 2001, 2000 and 1999, respectively, and $28.4 million was incurred prior to 1999. The majority of the costs will be evaluated over the next four years.

In June 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred with the associated asset retirement costs being capitalized as a part of the carrying amount of the long-lived asset. SFAS No. 143 also includes disclosure requirements that provide a description of asset retirement obligations and reconciliation of changes in the components of those obligations. The Company currently records its plugging and abandonment costs, net of salvage value, with respect to its natural gas and oil properties as additional DD&A expense using the units-of-production method. This statement will require the Company to recognize a liability for the fair value of its plugging and abandonment liability, excluding salvage value, with the associated costs as part of its natural gas and oil property balance. The Company is evaluating the future financial effects of adopting SFAS No. 143 and expects to adopt the standard effective January 1, 2003.

COMMODITY PRICE RISK MANAGEMENT ACTIVITIES

On January 1, 2001, the Company adopted SFAS No. 133, as amended, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 established accounting and reporting standards requiring that all derivative instruments be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in a derivative's fair value be realized currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset related results on the hedged item in the statement of operations and requires a company to formally document, designate and assess the effectiveness of transactions that qualify for hedge accounting.

STOCK OPTIONS

In October 1995, the FASB issued SFAS No. 123, "Accounting for Stock-Based Compensation." SFAS No. 123 encourages, but does not require, companies to record compensation cost for stock-based employee compensation plans at fair value. The Company has chosen to account for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Accordingly, compensation cost for stock options is measured as the excess, if any, of the fair value of the Common Stock at the date of the grant over the amount an employee must pay to acquire the Common Stock. See Note 6 of the Notes to Consolidated Financial Statements.

RELATED PARTIES

The Company paid $17.4 million in 2001 to affiliates of Baker Hughes Incorporated ("Baker Hughes"), an oilfield services company. Mr. Michael E. Wiley, a director of Spinnaker, serves as Chairman of the Board, Chief Executive Officer and President of Baker Hughes. The Company paid $83,000 and $528,000 in 2001 and 2000, respectively, to Cooper Cameron Corporation ("Cooper Cameron"), an oilfield services company. Mr. Sheldon R. Erikson, a director of Spinnaker, serves as Chairman of the Board, Chief Executive Officer and President of Cooper Cameron. The Company purchases oilfield goods, equipment and services from Baker Hughes, Cooper Cameron and other companies in the ordinary course of business. Spinnaker believes that these transactions are at arms-length and the charges and fees that it pays for such goods, equipment and services are competitive with the charges and fees of other companies providing oilfield goods, equipment and services to the oil and gas exploration and production industry.

RESULTS OF OPERATIONS

The following table sets forth certain operating information with respect to the natural gas and oil operations of the Company:

For the Year Ended December 31,	2001	2000	1999
PRODUCTION:			
Natural gas (MMcf)	51,234	28,845	11,962
Oil and condensate (MBbls)	310	225	180
Total (MMcfe)	53,094	30,194	13,044
REVENUES (in thousands):			
Natural gas	$212,238	$133,264	$ 29,839
Oil and condensate	7,718	6,775	3,668
Net hedging income (loss)	(9,580)	(18,656)	751
Total	$210,376	$121,383	$ 34,258
AVERAGE SALES PRICE PER UNIT:			
Natural gas revenues from production (per Mcf)	$ 4.14	$ 4.62	$ 2.49
Effects of hedging activities (per Mcf)	(0.18)	(0.59)	0.08
Average price (per Mcf)	$ 3.96	$ 4.03	$ 2.57
Oil and condensate revenues from production (per Bbl)	$ 24.90	$ 30.14	$ 20.33
Effects of hedging activities (per Bbl)	—	(7.16)	(0.57)
Average price (per Bbl)	$ 24.90	$ 22.98	$ 19.76
Total revenues from production (per Mcfe)	$ 4.14	$ 4.64	$ 2.57
Effects of hedging activities (per Mcfe)	(0.18)	(0.62)	0.06
Total average price (per Mcfe)	$ 3.96	$ 4.02	$ 2.63
EXPENSES (per Mcfe):			
Lease operating expenses	$ 0.23	$ 0.30	$ 0.41
Depreciation, depletion and amortization – natural gas and oil properties	$ 1.60	$ 1.57	$ 1.59
INCOME FROM OPERATIONS (in thousands)	$100,285	$ 57,264	$ 1,335

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

Revenues increased $89.0 million in 2001 compared to 2000. Excluding the effects of hedging activities, natural gas revenues increased $79.0 million and oil and condensate revenues increased $0.9 million. Losses resulting from hedging activities decreased by $9.1 million in 2001 compared to 2000, thereby improving revenues.

Production increased approximately 22.9 Bcfe in 2001 compared to 2000. Average daily production in 2001 was 145 MMcfe compared to 82 MMcfe in 2000. Natural gas production volumes increased 22.4 Bcf, contributing $123.9 million of the increase in natural gas revenues, excluding the effects of hedging activities, offset in part by $44.9 million related to lower average natural gas prices in 2001 compared to 2000. Oil and condensate production volumes increased 85 MBbls, contributing $2.8 million of the increase in oil and condensate revenues, offset in part by $1.9 million related to decreases in average oil and condensate prices. The rapid production declines of certain producing wells, combined with pipeline-mandated curtailments of certain facilities, shut-ins related to facility upgrades and less than anticipated results from workovers, resulted in lower production in the fourth quarter of 2001 compared to the prior quarter. The Company expects a further decline in production during the first quarter of 2002.

Lease operating expenses increased $3.1 million in 2001 compared to 2000. Of the total increase in lease operating expenses, $1.0 million was primarily related to workover activities in 2001 and $0.4 million was attributable to wells on new blocks that commenced production subsequent to December 31, 2000. The lease operating expense rate decreased 23 percent to $0.23 per Mcfe in 2001 compared to 2000 primarily due to increased production coupled with continued efficiencies gained in core operating areas, including the High Island 202 area.

DD&A increased $37.7 million in 2001 compared to 2000. The change in DD&A was attributable to an increase in production of 22.9 Bcfe and a slightly higher DD&A rate, which impacted DD&A by $36.0 million and $1.7 million, respectively.

General and administrative expenses increased $2.1 million in 2001 compared to 2000. The increase in general and administrative expenses was primarily due to higher employment-related costs resulting from the Company's recent growth.

The Company had in place both financial hedge and physical contracts with Enron North America Corp. at the time it filed for bankruptcy in December 2001. Spinnaker did not receive payment for fixed price swap contracts totaling $2.1 million, intended to hedge December 2001 natural gas sales, and $1.4 million related to November 2001 natural gas production sold to Enron entities. The Company recorded a net reserve of $3.1 million related to these receivables and has no other exposure to Enron Corp. and its subsidiaries.

Interest income increased $0.7 million in 2001 compared to 2000 primarily due to investment income associated with proceeds from the Company's public offering of Common Stock completed on August 16, 2000. Interest expense decreased $0.4 million in 2001 compared to 2000. The Company had no outstanding borrowings in 2001 compared to 2000.

Income tax provision increased $16.4 million in 2001 compared to 2000 and primarily relates to deferred income taxes accrued at a 36 percent effective tax rate in 2001 and a 35 percent effective tax rate in 2000.

The Company recognized net income of $66.2 million, or $2.45 per basic share and $2.34 per diluted share, in 2001 compared to net income of $38.6 million, or $1.70 per basic share and $1.61 per diluted share, in 2000.

YEAR ENDED DECEMBER 31, 2000 AS COMPARED TO THE YEAR ENDED DECEMBER 31, 1999

Revenues, including the effects of hedging activities, increased $87.1 million in 2000 compared to 1999. Excluding the effects of hedging activities, natural gas revenues increased $103.4 million and oil and condensate revenues increased $3.1 million in 2000 compared to 1999. Net natural gas and oil hedging losses increased $19.4 million in 2000 compared to 1999.

Production increased approximately 17.2 Bcfe in 2000 compared to 1999. Average daily production in 2000 was 82 MMcfe compared to 36 MMcfe in 1999. Natural gas production volumes increased 16.9 Bcf, primarily due to wells on 11 new blocks which commenced production in 2000, contributing $93.5 million of the increase in natural gas revenues, excluding the effects of hedging activities. Average natural gas prices increased, contributing $9.9 million of the increase in natural gas revenues. Oil and condensate production volumes increased approximately 45 MBbls, primarily due to wells on 11 new blocks which commenced production in 2000, contributing $2.4 million of the increase in oil and condensate revenues, excluding the effects of hedging activities. Average oil and condensate prices increased, contributing $0.7 million of the increase in oil and condensate revenues.

Lease operating expenses increased $3.6 million in 2000 compared to 1999. Of the total increase in lease operating expenses, $4.1 million was attributable to wells on 11 new blocks which commenced production in 2000, offset in part by $0.5 million, primarily related to major workover activities in 1999. Lease operating expenses per Mcfe in 1999 included approximately $0.13 per Mcfe associated with workovers on two wells and well control activities on another well. Lease operating expenses per Mcfe in 2000 included approximately $0.03 per Mcfe associated with workovers on four wells.

DD&A increased $26.8 million in 2000 compared to 1999. The increase in DD&A was primarily attributable to the 17.2 Bcfe increase in production volumes in 2000. The DD&A rate in 2000 decreased slightly from the DD&A rate in 1999.

General and administrative expenses increased $2.5 million in 2000 compared to 1999. The increase in general and administrative expenses was primarily due to employment-related costs associated with personnel additions during 1999 and 2000.

Interest income increased $2.4 million in 2000 compared to 1999 primarily due to investment income associated with proceeds from the Company's public offering of Common Stock completed on August 16, 2000. Interest expense, net of capitalized interest, decreased $2.1 million in 2000 compared to 1999. The Company had substantially less outstanding borrowings in 2000 compared to 1999. At December 31, 2000, the Company had no outstanding borrowings.

An income tax provision of $20.9 million was recorded in 2000 based on the Company's transition to profitability in 2000. No income tax benefit was recorded in 1999 due to the uncertainty of future realization as the Company had not established a history of operating income.

The Company recognized net income of $38.6 million, or $1.70 per basic share and $1.61 per diluted share, in 2000 compared to a net loss of $1.3 million in 1999. After dividends of $7.9 million on Preferred Stock that is no longer outstanding, the Company recognized a net loss available to common stockholders of $9.2 million, or a loss of $1.11 per basic and diluted share, in 1999.

LIQUIDITY AND CAPITAL RESOURCES

The Company has experienced and expects to continue to experience substantial capital requirements, primarily due to its active exploration and development programs in the Gulf of Mexico. Capital expenditures in 2001, 2000 and 1999 were $288.8 million, $163.7 million and $85.1 million, respectively. Spinnaker has capital expenditure plans for 2002 totaling approximately $250 million. During 2001, Spinnaker participated in a significant deep water oil discovery, Front Runner, with a 25 percent non-operator working interest. The Company participated in five consecutive successful wells and sidetracks in testing the reservoirs on these blocks. Spinnaker has incurred capital expenditures associated with Front Runner of approximately $30 million through December 31, 2001 and expects to incur an aggregate of approximately $110 million in future development costs during 2002 and 2003. The 2002 capital expenditure plans include approximately $40 million related to the Front Runner production facilities. The Company is considering various financing alternatives for the cost of these facilities, including a lease.

Natural gas and oil prices have a significant impact on the Company's cash flows available for capital expenditures and its ability to borrow and raise additional capital. The amount the Company can borrow under its Credit Facility is subject to periodic re-determination based in part on changing expectations of future prices. Lower prices may also reduce the amount of natural gas and oil that the Company can economically produce. Additionally, the rapid production declines of certain producing wells, combined with pipeline-mandated curtailments of certain facilities, shut-ins related to facility upgrades and less than anticipated results from workovers, resulted in lower production in the fourth quarter of 2001 compared to the prior quarter. The Company expects a further decline in production during the first quarter of 2002.

While the Company believes that working capital, cash flows from operations and available borrowings under its Credit Facility will be sufficient to meet its capital requirements in the next twelve months, additional debt or equity financing may be required in the future to fund its growth and exploration and development programs. In the event additional capital resources are unavailable, the Company may curtail its drilling, development and other activities or be forced to sell some of its assets on an untimely or unfavorable basis.

Spinnaker has an effective shelf registration statement relating to the potential public offer and sale by the Company or certain affiliates of up to $300.0 million of any combination of debt securities, preferred stock, common stock, warrants, stock purchase contracts and trust preferred securities from time to time or when financing needs arise. The registration statement does not provide assurance that the Company will or could sell any such securities.

Cash and cash equivalents decreased $49.8 million to $14.1 million at December 31, 2001 from $63.9 million at December 31, 2000. The decrease in cash and cash equivalents resulted from $266.4 million used in investing activities, offset in part by $209.4 million provided by operating activities and $7.2 million provided by financing activities.

OPERATING ACTIVITIES

Net cash provided by operating activities in 2001 increased 155 percent to $209.4 million from $82.0 million in 2000, primarily as a result of higher natural gas production. Cash flow from operations depends on the Company's ability to increase production through its exploration and development programs and the prices of natural gas and oil. The Company has made significant investments to expand its operations in the Gulf of Mexico. These investments have resulted in an increase in the Company's average daily production.

The Company sells its natural gas and oil production under fixed or floating market price contracts. Spinnaker enters into hedging arrangements from time to time to reduce its exposure to fluctuations in natural gas and oil prices and achieve more predictable cash flow. However, these contracts also limit the benefits the Company would realize if prices increase. See "Quantitative and Qualitative Disclosures About Market Risk."

The Company's cash flow from operations also depends on its ability to manage working capital, including accounts receivable, accounts payable and accrued liabilities. The decrease in accounts receivable of $21.5 million was primarily due to a decrease in accrued natural gas and oil sales of $21.6 million as a result of substantially lower natural gas prices in December 2001 compared to December 2000, partially offset by a net increase in all other receivables of $0.1 million. The increase in accounts payable and accrued liabilities of $18.8 million was primarily due to costs associated with increased drilling and development activities at the end of 2001 compared to the end of 2000, including non-cash activity of $14.8 million for property related payables and $7.2 million related to the tax effect of the fair market value of current derivatives.

INVESTING ACTIVITIES

Net cash used in investing activities in 2001 increased 48 percent to $266.4 million from $180.2 million in 2000, primarily due to higher capital expenditures. Natural gas and oil capital expenditures in 2001 were $287.2 million compared to $161.8 million in 2000. The Company also purchased short-term investments of $29.6 million and sold short-term investments of $52.0 million.

The Company drilled 35 wells in 2001, 19 of which were successful. In 2000, the Company drilled 28 wells, 16 of which were successful. Since inception and through December 31, 2001, the Company has drilled 94 wells, 56 of which were successful, representing a success rate of approximately 60 percent.

The Company has capital expenditure plans for 2002 totaling approximately $250 million, primarily for costs related to exploration and development programs. The 2002 budget includes development costs that are contingent on the success of exploratory drilling. The Company does not anticipate any significant abandonment or dismantlement costs in 2002. Actual levels of capital expenditures may vary due to many factors, including drilling results, natural gas and oil prices, the availability of capital, industry conditions, acquisitions, decisions of operators and other prospect owners and the prices of drilling rig dayrates and other oilfield goods and services.

FINANCING ACTIVITIES

Net cash provided by financing activities in 2001 decreased 95 percent to $7.2 million from $141.6 million in 2000, primarily due to proceeds from a Common Stock offering in 2000 of $138.9 million. The net cash provided by financing activities in 2001 related to stock option exercises.

On December 28, 2001, the Company completed an unsecured $200.0 million Credit Facility with a group of seven banks. The three-year facility has an initial borrowing base of $125.0 million that is re-determined on April 30 and September 30 each year. The banks and Spinnaker also have the option to request one additional re-determination each year. The Company has the option to elect to use a base interest rate as described below or the LIBOR rate plus, for each such rate, a spread based on the percent of the borrowing base used at that time. The base interest rate under the Credit Facility is a fluctuating rate of interest equal to the higher of either the Toronto-Dominion Bank's base rate for dollar advances made in the United States or the Federal Funds Rate plus 0.5 percent per annum. The Credit Facility contains covenants and restrictive provisions. At December 31, 2001, the Company was in compliance with the covenants and had no outstanding borrowings under the Credit Facility. As of March 7, 2002, the Company had outstanding borrowings of $21.0 million under the Credit Facility. For a description of the covenants and restrictive provisions in the Credit Facility, see Note 3 of the Notes to Consolidated Financial Statements.

CONTRACTUAL OBLIGATIONS

The Company leases administrative offices, office equipment and oil and gas equipment under non-cancelable operating leases. In addition, the Company has agreed to purchase $2.0 million of seismic-related services from PGS prior to December 31, 2002. Through December 31, 2001, the Company paid PGS a total of approximately $1.3 million for these services. The Company had no debt or capital leases outstanding as of December 31, 2001. The Company has incurred obligations in the ordinary course of business under purchase and service agreements which are not included in the table below. Obligations under operating leases and the Data Agreement as of December 31, 2001 are as follows:

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Operating leases	$ 6,914	$ 1,222	$ 3,858	$ 1,834	$ —
Unconditional Data Agreement obligations	655	655	—	—	—
Total	$ 7,569	$ 1,877	$ 3,858	$ 1,834	$ —

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

INTEREST RATE RISK

The Company is exposed to changes in interest rates. Changes in interest rates affect the interest earned on cash, cash equivalents and short-term investments and the interest rate paid on borrowings under the Credit Facility. The Company does not currently use interest rate derivative instruments to manage exposure to interest rate changes, but may do so in the future.

COMMODITY PRICE RISK

The Company's revenues, profitability and future growth depend substantially on prevailing prices for natural gas and oil. Prices also affect the amount of cash flow available for capital expenditures and the Company's ability to borrow and raise additional capital. Lower prices may also reduce the amount of natural gas and oil that the Company can economically produce. The Company sells its natural gas and oil production under fixed or floating market price contracts. Spinnaker enters into hedging arrangements from time to time to reduce its exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. However, these contracts also limit the benefits the Company would realize if prices increase. These financial arrangements take the form of swap contracts or costless collars and are placed with major trading counterparties the Company believes represent minimum credit risks. Spinnaker cannot provide assurance that these trading counterparties will not become credit risks in the future. The Company had in place both financial hedge and physical contracts with Enron North America Corp. at the time it filed for bankruptcy in December 2001. Spinnaker did not receive payment as required under these contracts. Under its current hedging practice, the Company generally does not hedge more than 66⅔ percent of its estimated twelve-month production quantities without the prior approval of the risk management committee of the board of directors.

The Company enters into New York Mercantile Exchange ("NYMEX") related swap contracts and collar arrangements from time to time. The Company's swap contracts will settle based on the reported settlement price on the NYMEX for the last trading day of each month for natural gas. In a swap transaction, the counterparty is required to make a payment to the Company for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. The Company is required to make a payment to the counterparty for the difference between the fixed price and the settlement price if the settlement price is above the fixed price. Some of the master agreements require the Company to make margin payments to counterparties when net exposure exceeds a certain threshold. As of March 7, 2002, Spinnaker's commodity price risk management positions in fixed price natural gas swap contracts were as follows:

Period	Average Daily Volume (MMBtu)	Weighted Average Price Per MMBtu
First Quarter 2002	100,000	$ 3.23
Second Quarter 2002	93,407	3.20
Third Quarter 2002	80,000	3.37
Fourth Quarter 2002	76,685	3.58
Full Year 2003	25,000	3.27

Based upon the Company's assessment of its derivative contracts at December 31, 2001, it reported (i) a net current asset of $20.6 million and non-current asset of $1.7 million and (ii) accumulated other comprehensive income of $14.5 million, net of income taxes of $7.8 million. The Company recognized no ineffective component of the derivatives in earnings in 2001. In connection with monthly settlements, the Company recognized net hedging losses in revenues of $9.6 million and $18.7 million in 2001 and 2000, respectively. Based on future natural gas prices as of December 31, 2001, the Company would reclassify $20.6 million from accumulated other comprehensive income to earnings within the next 12 months. The amounts ultimately reclassified into earnings will vary due to changes in the fair value of the open derivative contracts prior to settlement.

Report of Independent Public Accountants

TO THE BOARD OF DIRECTORS AND STOCKHOLDERS OF SPINNAKER EXPLORATION COMPANY:

We have audited the accompanying consolidated balance sheets of Spinnaker Exploration Company (a Delaware corporation) and subsidiaries, as of December 31, 2001 and 2000, and the related consolidated statements of operations, equity and cash flows for each of the three years in the period ended December 31, 2001. 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. 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 consolidated financial position of Spinnaker Exploration Company and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As explained in Note 1 to the consolidated financial statements, effective January 1, 2001, the Company changed its method of accounting for its derivative instruments.

ARTHUR ANDERSEN LLP

Houston, Texas
February 15, 2002

Consolidated Balance Sheets

(IN THOUSANDS, EXCEPT SHARE AND PER SHARE DATA)

As of December 31,	2001	2000
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 14,061	$ 63,910
Short-term investments	—	22,387
Accounts receivable, net of allowance for doubtful accounts of $3,059 and $0 at December 31, 2001 and 2000, respectively	24,129	45,594
Hedging assets	20,593	—
Other	3,664	6,402
Total current assets	62,447	138,293
PROPERTY AND EQUIPMENT:		
Oil and gas, on the basis of full-cost accounting:		
Proved properties	575,806	293,002
Unproved properties and properties under development, not being amortized	102,881	83,165
Other	7,245	5,642
	685,932	381,809
Less – Accumulated depreciation, depletion and amortization	(163,359)	(77,428)
Total property and equipment	522,573	304,381
OTHER ASSETS	2,296	30
Total assets	$ 587,316	$ 442,704
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 32,383	$ 28,616
Accrued liabilities and other	50,718	35,672
Total current liabilities	83,101	64,288
DEFERRED INCOME TAXES	45,723	17,157
COMMITMENTS AND CONTINGENCIES (Note 11)		
EQUITY:		
Preferred stock, $0.01 par value; 10,000,000 shares authorized; no shares issued and outstanding at December 31, 2001 and 2000, respectively	—	—
Common stock, $0.01 par value; 50,000,000 shares authorized; 27,308,912 shares issued and 27,293,264 shares outstanding at December 31, 2001 and 26,494,593 shares issued and 26,476,817 shares outstanding at December 31, 2000	273	265
Additional paid-in capital	365,993	349,506
Retained earnings	77,758	11,532
Less: Treasury stock, at cost, 15,648 and 17,776 shares at December 31, 2001 and 2000, respectively	(39)	(44)
Accumulated other comprehensive income	14,507	—
Total equity	458,492	361,259
Total liabilities and equity	$ 587,316	$ 442,704

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Operations

(IN THOUSANDS, EXCEPT PER SHARE DATA)

For the Year Ended December 31,	2001	2000	1999
REVENUES	$210,376	$121,383	$ 34,258
EXPENSES:			
Lease operating expenses	12,132	9,009	5,411
Depreciation, depletion and amortization — natural gas and oil properties	85,059	47,451	20,788
Depreciation and amortization — other	398	309	213
General and administrative	9,443	7,350	4,860
Charges related to Enron bankruptcy	3,059	—	—
Stock appreciation rights expense	—	—	1,651
Total expenses	110,091	64,119	32,923
INCOME FROM OPERATIONS	100,285	57,264	1,335
OTHER INCOME (EXPENSE):			
Interest income	3,574	2,908	528
Interest expense, net	(381)	(748)	(2,805)
Total other income (expense)	3,193	2,160	(2,277)
INCOME (LOSS) BEFORE INCOME TAXES	103,478	59,424	(942)
Income tax provision	37,252	20,858	—
INCOME (LOSS) BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	66,226	38,566	(942)
Cumulative effect of change in accounting principle (Note 1)	—	—	(395)
NET INCOME (LOSS)	66,226	38,566	(1,337)
ACCRUAL OF DIVIDENDS ON PREFERRED STOCK	—	—	(7,911)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ 66,226	$ 38,566	$ (9,248)
BASIC INCOME (LOSS) PER COMMON SHARE:			
Income (loss) before cumulative effect of change in accounting principle	$ 2.45	$ 1.70	$ (1.06)
Cumulative effect of change in accounting principle	—	—	(0.05)
NET INCOME (LOSS) PER COMMON SHARE	$ 2.45	$ 1.70	$ (1.11)
DILUTED INCOME (LOSS) PER COMMON SHARE:			
Income (loss) before cumulative effect of change in accounting principle	$ 2.34	$ 1.61	$ (1.06)
Cumulative effect of change in accounting principle	—	—	(0.05)
NET INCOME (LOSS) PER COMMON SHARE	$ 2.34	$ 1.61	$ (1.11)
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:			
Basic	27,079	22,679	8,355
Diluted	28,360	24,011	8,355

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Equity

(IN THOUSANDS, EXCEPT SHARES AND DIVIDENDS PER SHARE DATA)

	Shares Issued		Par Value		Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Treasury Stock	Accumulated Other Comprehensive Income	Total Equity	Comprehensive Income (Loss)
	Preferred	Common	Preferred	Common						
Balance, December 31, 1998	3,030,920	4,082,200	$ 30	$ 20	$ 74,649	$ (17,786)	$ —	$ —	$ 56,913	
Net loss	—	—	—	—	—	(1,337)	—	—	(1,337)	$ (1,337)
Comprehensive loss										$ (1,337)
Common stock split	—	—	—	20	(20)	—	—	—	—	
Common stock issuance	—	9,076,096	—	91	111,260	—	—	—	111,351	
Exercise of stock options	—	5,808	—	—	29	—	—	—	29	
Preferred stock dividends ($3.00 per share)	—	—	—	—	—	(7,911)	—	—	(7,911)	
Conversion of preferred stock to common stock	(3,030,920)	6,061,840	(30)	61	(31)	—	—	—	—	
Reinvestment of preferred stock dividends into common stock	—	1,200,248	—	12	16,299	—	—	—	16,311	
Stock compensation costs	—	—	—	—	150	—	—	—	150	
Stock appreciation rights termination	—	—	—	—	1,651	—	—	—	1,651	
Treasury stock	—	—	—	—	—	—	(55)	—	(55)	
Balance, December 31, 1999	—	20,426,192	—	204	203,987	(27,034)	(55)	—	177,102	
Net income	—	—	—	—	—	38,566	—	—	38,566	$ 38,566
Comprehensive income										$ 38,566
Common stock issuance	—	5,600,000	—	56	138,342	—	—	—	138,398	
Exercise of stock options	—	462,478	—	5	3,195	—	11	—	3,211	
Employer contributions to 401(k) Plan	—	5,923	—	—	148	—	—	—	148	
Stock compensation costs	—	—	—	—	158	—	—	—	158	
Tax benefit associated with exercise of non-qualified stock options	—	—	—	—	3,676	—	—	—	3,676	
Balance, December 31, 2000	—	26,494,593	—	265	349,506	11,532	(44)	—	361,259	
Net income	—	—	—	—	—	66,226	—	—	66,226	$ 66,226
Other comprehensive income, net of tax:										
Cumulative effect of accounting change for derivative financial instruments	—	—	—	—	—	—	—	(27,126)	(27,126)	(27,126)
Net change in fair value of derivative financial instruments	—	—	—	—	—	—	—	35,502	35,502	35,502
Financial derivative settlements reclassed to income	—	—	—	—	—	—	—	6,131	6,131	6,131
Comprehensive income										$ 80,733
Exercise of stock options	—	808,863	—	8	7,142	—	5	—	7,155	
Employer contributions to 401(k) Plan	—	5,456	—	—	216	—	—	—	216	
Stock compensation costs	—	—	—	—	114	—	—	—	114	
Tax benefit associated with exercise of non-qualified stock options	—	—	—	—	9,015	—	—	—	9,015	
Balance, December 31, 2001	—	27,308,912	$ —	$ 273	$365,993	$ 77,758	$ (39)	$ 14,507	$ 458,492	

The accompanying notes are an integral part of these consolidated financial statements.

SPINNAKER EXPLORATION COMPANY

Consolidated Statements of Cash Flows

(IN THOUSANDS)

For the Year Ended December 31,	2001	2000	1999
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 66,226	$ 38,566	$ (1,337)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	85,457	47,760	21,001
Deferred income tax expense	36,977	20,833	—
Other	549	306	—
Stock appreciation rights expense	—	—	1,651
Cumulative effect of change in accounting principle	—	—	395
Change in components of working capital:			
Accounts receivable	21,465	(34,799)	(6,974)
Accounts payable and accrued liabilities	(3,216)	14,861	(636)
Other current assets and other	1,979	(5,523)	805
Net cash provided by operating activities	209,437	82,004	14,905
CASH FLOWS FROM INVESTING ACTIVITIES:			
Oil and gas properties	(302,046)	(198,787)	(78,894)
Change in property related payables	14,821	36,976	(5,291)
Proceeds from sale of natural gas and oil assets	—	5,971	—
Purchases of other property and equipment	(1,603)	(1,928)	(916)
Purchases of short-term investments	(29,627)	(22,387)	—
Sales of short-term investments	52,014	—	—
Net cash used in investing activities	(266,441)	(180,155)	(85,101)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	—	17,000	53,000
Payments on borrowings	—	(17,000)	(72,000)
Proceeds from issuance of common stock	—	138,936	108,720
Common stock issuance costs	—	(538)	(1,109)
Proceeds from exercise of stock options	7,155	3,211	29
Preferred stock dividends	—	—	(78)
Acquisition of treasury stock	—	—	(55)
Net cash provided by financing activities	7,155	141,609	88,507
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(49,849)	43,458	18,311
CASH AND CASH EQUIVALENTS, beginning of year	63,910	20,452	2,141
CASH AND CASH EQUIVALENTS, end of year	$ 14,061	$ 63,910	$ 20,452
SUPPLEMENTAL CASH FLOW DISCLOSURES:			
Cash paid for interest, net of amounts capitalized	$ 190	$ 380	$ 2,591
Cash paid for income taxes, net	275	25	—
SUPPLEMENTAL NON-CASH INVESTING AND FINANCING ACTIVITIES:			
Reinvestment of preferred dividends payable into common stock	$ —	$ —	$ 16,311
Issuance of common stock for amended seismic data rights	—	—	2,900

The accompanying notes are an integral part of these consolidated financial statements.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Spinnaker Exploration Company ("Spinnaker" or the "Company") was formed in 1996 and engages in the exploration, development and production of natural gas and oil properties in the U.S. Gulf of Mexico.

On September 28, 1999, the Company priced its initial public offering of 8,000,000 shares of common stock, par value $0.01 per share ("Common Stock"), and commenced trading the following day. After payment of underwriting discounts and commissions, the Company received net proceeds of $108.7 million on October 4, 1999. With a portion of the proceeds, the Company retired all outstanding debt of $72.0 million. In connection with the initial public offering, the Company converted all outstanding Series A Convertible Preferred Stock, par value $0.01 per share ("Preferred Stock"), into shares of Common Stock, and certain shareholders reinvested preferred dividends payable of $16.3 million into shares of Common Stock.

A summary of significant accounting policies followed in the preparation of the accompanying consolidated financial statements is set forth below:

GENERAL

The accompanying consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in the United States and pursuant to the rules and regulations of the Securities and Exchange Commission (the "Commission").

PRINCIPLES OF CONSOLIDATION

The accompanying consolidated financial statements include the activities and accounts of the Company and its subsidiaries, all of which are wholly owned. All significant intercompany transactions and balances are eliminated in consolidation.

USE OF ESTIMATES

The preparation of financial statements in conformity with accounting principles generally accepted in the United States 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 amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates include depreciation, depletion and amortization ("DD&A") of proved natural gas and oil properties. Natural gas and oil reserve estimates, which are the basis for unit-of-production DD&A and the full cost ceiling test, are inherently imprecise and are expected to change as future information becomes available.

CASH EQUIVALENTS

The Company considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents.

SHORT-TERM INVESTMENTS

Short-term investments include highly liquid investments in commercial paper with maturities greater than three months when purchased.

OTHER CURRENT ASSETS

Other current assets include unamortized debt financing costs of $328,000 and $114,000 at December 31, 2001 and 2000, respectively. Other non-current assets include unamortized debt financing costs of $554,000 at December 31, 2001. These costs are amortized to interest expense over the three-year term of the related credit facility. Amortization of these and other debt financing costs included in interest expense was $219,000, $354,000 and $576,000 for the years ended December 31, 2001, 2000 and 1999, respectively. See Note 3.

NATURAL GAS AND OIL PROPERTIES

The Company uses the full cost method of accounting for its investment in natural gas and oil properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of exploring for natural gas and oil are capitalized. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals and costs related to such activities. Exclusive of field-level costs, Spinnaker capitalized $5.1 million, $3.8 million and $2.5 million of general and administrative costs in 2001, 2000 and 1999, respectively. These capitalized costs are directly related to exploration activities and include salaries, employee benefits, costs of consulting services and other related expenses. Costs associated with production and general corporate activities are expensed in the period incurred. Interest costs related to unproved properties and properties under development are also capitalized to natural gas and oil properties. Spinnaker capitalized interest of $0, $17,000 and $966,000 in 2001, 2000 and 1999, respectively. Sales of natural gas and oil properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of natural gas and oil.

The Company computes the provision for DD&A of natural gas and oil properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the amortization base until the properties associated with these costs are evaluated. In addition to costs associated with evaluated properties, the amortization base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values. Certain future development costs may be excluded from amortization when incurred in connection with major development projects expected to entail significant costs to ascertain the quantities of proved reserves attributable to the properties under development. The amounts that may be excluded are applicable portions of the costs that relate to the major development project and have not previously been included in the amortization base and the estimated future expenditures associated with the development project. Such costs may be excluded from costs to be amortized until the earlier determination of whether additional reserves are proved or impairment occurs. The Company has excluded from amortization a portion of the estimated future expenditures associated with common development costs on one of its deep water discoveries based on existing proved reserves to total proved reserves expected to be established upon completion of the deep water project.

Capitalized costs of natural gas and oil properties, net of accumulated DD&A and related deferred taxes, are limited to the estimated future net cash flows from proved natural gas and oil reserves, including the effects of hedging activities, discounted at 10 percent, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (the full cost ceiling). If capitalized costs exceed the full cost ceiling, the excess is charged to write-down of natural gas and oil properties in the quarter in which the excess occurs. Given the volatility of natural gas and oil prices, it is reasonably possible that the Company's estimate of discounted future net cash flows from proved natural gas and oil reserves will change in the near term. If natural gas and oil prices decline, even if for only a short period of time, or if the Company has downward revisions to its estimated proved reserves, it is possible that write-downs of natural gas and oil properties could occur in the future.

The costs associated with unevaluated leasehold acreage, unamortized seismic data, wells currently drilling and capitalized interest are not initially included in the amortization base. Leasehold costs are either transferred to the amortization base with the costs of drilling the related well or are assessed quarterly for possible impairment or reduction in value. Leasehold costs are transferred to the amortization base if a reduction in value has occurred. Of the $102.9 million of net unproved property costs at December 31, 2001 excluded from the amortizable base, net costs of $19.7 million, $42.5 million and $12.3 million were incurred in 2001, 2000 and 1999, respectively, and $28.4 million was incurred prior to 1999. The majority of the costs will be evaluated over the next four years.

Substantially all the Company's exploration activities are conducted jointly with others and, accordingly, the natural gas and oil property balances reflect only its proportionate interest in such activities.

OTHER PROPERTY AND EQUIPMENT

Other property and equipment consists of computer hardware and software, office furniture and leasehold improvements. The Company is depreciating these assets using the straight-line method based upon estimated useful lives ranging from three to five years.

ORGANIZATION COSTS

In April 1998, the American Institute of Certified Public Accountants issued Statement of Position 98-5 ("SOP 98-5"), "Reporting on the Costs of Start-Up Activities," which requires that costs for start-up activities and organization costs be expensed as incurred and not capitalized as had previously been allowed. SOP 98-5 was effective for financial statements for fiscal years beginning after 1998. The Company adopted this policy in the first quarter of 1999 and recorded a charge related to this accounting change of $395,000 in conjunction with the write-off of previously capitalized organization costs.

REVENUE RECOGNITION POLICY

The Company records as revenue only that portion of production sold and delivered and allocable to its ownership interest in the related property. Imbalances arise when a purchaser takes delivery of more or less volume from a property than the Company's actual interest in the production from that property. Such imbalances are reduced either by subsequent recoupment of over-and-under deliveries or by cash settlement, as required by applicable contracts. Under-imbalances included in accounts receivable were $706,000 and $458,000 at December 31, 2001 and 2000, respectively. Over-imbalances included in accrued liabilities were $650,000 and $720,000 at December 31, 2001 and 2000, respectively.

INCOME TAXES

Under Statement of Financial Accounting Standards ("SFAS") No. 109, "Accounting for Income Taxes," deferred income taxes are recognized at each year-end for the future tax consequences of differences between the tax bases of assets and liabilities and their financial reporting amounts based on enacted tax laws and statutory tax rates applicable to the periods in which the differences are expected to affect taxable income. Valuation allowances are established when necessary to reduce deferred tax assets to the amount expected to be realized.

STOCK OPTIONS

In October 1995, the Financial Accounting Standards Board ("FASB") issued SFAS No. 123, "Accounting for Stock-Based Compensation." SFAS No. 123 encourages, but does not require, companies to record compensation cost for stock-based employee compensation plans at fair value. The Company has chosen to account for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Accordingly, compensation cost for stock options is measured as the excess, if any, of the fair value of the Common Stock at the date of the grant over the amount an employee must pay to acquire the Common Stock. See Note 6.

STOCK SPLIT

On September 1, 1999, the Company declared a two-for-one stock split on the Common Stock (the "Stock Split"). All references to the number of common shares and per share amounts elsewhere in the Consolidated Financial Statements and Notes thereto have been restated as appropriate to reflect the effect of the Stock Split for all periods presented.

NEW ACCOUNTING PRONOUNCEMENTS

On January 1, 2001, the Company adopted SFAS No. 133, as amended, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 established accounting and reporting standards requiring that all derivative instruments be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in a derivative's fair value be realized currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset related results on the hedged item in the statement of operations and requires a company to formally document, designate and assess the effectiveness of transactions that qualify for hedge accounting. Upon adoption of SFAS No. 133 on January 1, 2001, the

Company designated its open derivative contracts as cash flow hedges and recorded (i) a net current liability of $41.7 million, representing the fair market value of all derivatives on that date and (ii) a reduction of equity through accumulated other comprehensive income of $27.1 million, representing the fair market value of the derivatives as of January 1, 2001, net of income taxes of $14.6 million.

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred with the associated asset retirement costs being capitalized as a part of the carrying amount of the long-lived asset. SFAS No. 143 also includes disclosure requirements that provide a description of asset retirement obligations and reconciliation of changes in the components of those obligations. The Company currently records its plugging and abandonment costs, net of salvage value, with respect to its natural gas and oil properties as additional DD&A expense using the units-of-production method. This statement will require the Company to recognize a liability for the fair value of its plugging and abandonment liability, excluding salvage value, with the associated costs as part of its natural gas and oil property balance. The Company is evaluating the future financial effects of adopting SFAS No. 143 and expects to adopt the standard effective January 1, 2003.

FINANCIAL INSTRUMENTS AND PRICE RISK MANAGEMENT ACTIVITIES

At December 31, 2001, the Company's financial instruments consisted of cash and cash equivalents, receivables, payables and derivative instruments. The carrying amounts of cash and cash equivalents, receivables and payables approximate fair value because of the short-term nature of these items. The Company enters into hedging arrangements from time to time to reduce its exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. These hedging arrangements take the form of swap contracts or costless collars and are placed with major trading counterparties the Company believes represent minimum credit risks. Under its current hedging practice, the Company generally does not hedge more than 66⅔ percent of its estimated twelve-month production quantities without the prior approval of the risk management committee of the board of directors.

CONCENTRATION OF CREDIT RISK

Financial instruments that potentially subject the Company to concentration of credit risk consist principally of cash equivalents and trade accounts receivable. Management believes that the credit risk posed by this concentration is offset by the creditworthiness of the Company's customer base.

Derivative contracts also subject the Company to concentration of credit risk. Management believes that the credit risk posed by this concentration is mitigated by its hedging policy. The hedging policy requires that (i) at no time will any hedging agreement of any nature have a counterparty with a minimum long-term senior unsecured indebtedness rating less than "BBB+" by Standard & Poors Corporation or "Baa1" by Moody's Investors Services, Inc. at the time that such counterparty entered into the relevant transaction under such hedging agreement and (ii) at no time will exposure to any single counterparty exceed 25 percent of the estimated twelve-month production volumes from total proved reserves.

The Company had in place both financial hedge and physical contracts with Enron North America Corp. at the time it filed for bankruptcy in December 2001. Spinnaker did not receive payment for fixed price swap contracts totaling $2.1 million, intended to hedge December 2001 natural gas sales, and $1.4 million related to November 2001 natural gas production sold to Enron entities. The Company recorded a net reserve of $3.1 million related to these receivables and has no other exposure to Enron Corp. and its subsidiaries.

RISK FACTORS

The Company's revenues, profitability, cash flow and future growth rates are substantially dependent upon the price of and demand for natural gas and oil. Prices for natural gas and oil are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors that are beyond the control of the Company. The Company is also dependent upon the continued success of its exploratory drilling program. Other factors that could affect revenues, profitability, cash flow and future growth rates include the inherent uncertainties in reserve estimates, the concentration of production and reserves in a small number of offshore properties, relatively short production periods for Gulf of Mexico properties, hedging production and the ability to replace reserves and finance growth.

2. ACCOUNTS RECEIVABLE AND ACCRUED LIABILITIES:

Supplemental disclosures related to accounts receivable and accrued liabilities and other are as follows (in thousands):

December 31,	2001	2000
Natural gas and oil sales	$ 10,679	$ 32,328
Hedging receivable	2,093	—
Joint interest billings	8,735	10,466
Insurance claims receivable	4,593	1,581
Other receivables	1,088	1,219
Allowance for doubtful accounts	(3,059)	—
Total accounts receivable	$ 24,129	$ 45,594
Accrued liabilities	$ 43,510	$ 35,672
Deferred income taxes associated with hedging activities	7,208	—
Total accrued liabilities and other	$ 50,718	$ 35,672

3. DEBT:

In September 1998, the Company entered into an $85.0 million credit agreement ("Credit Agreement") with certain financial institutions. The Credit Agreement was secured by the Company's interests in natural gas and oil properties and by certain guarantees of Petroleum Geo-Services ASA ("PGS") and Warburg, Pincus Ventures L.P. ("Warburg"). With proceeds from the initial public offering, the Company paid the outstanding borrowings of $72.0 million as of October 4, 1999. Interest expense related to the Credit Agreement was $2.4 million for the year ended December 31, 1999, excluding amounts related to the stock issuances for guarantees. In consideration for providing guarantees under the Credit Agreement, PGS and Warburg were entitled to receive Common Stock. Such stock issuances were accounted for in interest expense at the fair value of the guarantees provided and amounted to $840,000 in 1999. The overall weighted average interest rate for borrowings outstanding under the Credit Agreement was 5.71 percent in 1999. The Credit Agreement was scheduled to mature on December 31, 1999; however, the Company amended and restated the original Credit Agreement in October 1999.

In October 1999, the Company, Bank of Montreal and Credit Suisse First Boston entered into the $25.0 million Amended and Restated 364-Day Credit Agreement ("First Amended Credit Agreement"). The weighted average interest rate for borrowings outstanding under the First Amended Credit Agreement was 8.72 percent in 2000. The First Amended Credit Agreement was amended on July 20, 2000. The Second Amended and Restated Credit Agreement provided a $75.0 million credit facility ("Second Amended Credit Agreement") with an initial borrowing base of $40.0 million and an original term of 364 days. The borrowing base as of December 31, 2000 was $30.0 million. The Second Amended Credit Agreement was renewed for an additional 364-day term on July 18, 2001 before being terminated on December 28, 2001.

On December 28, 2001, the Company replaced the Second Amended Credit Agreement with an unsecured $200.0 million credit facility ("Credit Facility") with a group of seven banks. The three-year facility has an initial borrowing base of $125.0 million that is re-determined on April 30 and September 30 each year. The banks and Spinnaker also have the option to request one additional re-determination each year. The Company has the option to elect to use a base interest rate as described below or the LIBOR rate plus, for each such rate, a spread based on the percent of the borrowing base used at that time. The base interest rate under the Credit Facility is a fluctuating rate of interest equal to the higher of either the Toronto-Dominion Bank's base rate for dollar advances made in the United States or the Federal Funds Rate plus 0.5 percent per annum. The Credit Facility contains covenants and restrictive provisions, including the following limitations, subject to some exceptions, where the Company:

- may not incur any other indebtedness from borrowings, except for indebtedness arising under hedging agreements, indebtedness incurred in the ordinary course of business not to exceed $1.0 million, unsecured vendor indebtedness of the Company related to purchases of 2-D and 3-D seismic data made in the ordinary course of business in an amount not to exceed $25.0 million, other unsecured indebtedness in an amount not to exceed $10.0 million in the aggregate;

- may not incur any liens upon properties or assets other than permitted liens securing indebtedness of up to $1.0 million, liens on the 2-D and 3-D seismic data securing the indebtedness permitted to acquire such data, pledges or deposits to secure hedging agreements up to $15.0 million, liens on property required as a condition to enter into a synthetic lease transaction in the ordinary course of business and other liens in the ordinary course of business;
- may not dispose of any assets or properties except obsolete equipment, inventory sold in the ordinary course of business, reserves in non-proved categories, a second license in certain seismic data, or interests in natural gas and oil properties included in the borrowing base in an aggregate amount not to exceed $25.0 million in any fiscal year;
- may not make or pay any dividend, distribution or payment in respect of capital stock nor purchase, redeem, acquire, retire or permit any reduction or retirement of capital stock in excess of $10.0 million in any fiscal year;
- must maintain the ratio of consolidated current assets to consolidated current liabilities as of the end of each fiscal quarter so that it is not less than 1.00 to 1.00. For purposes of the calculation, availability under the Credit Facility is included as current assets, any payments of principal owing under the Credit Facility required to be repaid within one year from the time of the calculation are excluded from current liabilities and mark-to-market hedging exposure is excluded from both current assets and current liabilities;
- must maintain a tangible net worth so that it is not less than the sum of 80 percent of the tangible net worth as of September 30, 2001, plus 50 percent of the adjusted consolidated net income for each fiscal quarter since the closing of the Credit Facility, plus 75 percent of the proceeds from the sale of any security, including without limitation, common equity, preferred equity or other equity interests or equity securities including warrants, options and the like issued after the closing of the Credit Facility; and
- may not enter into any hedging agreement unless the percent of volumes to be hedged to estimated production volumes for such month from total internally-projected proved reserves does not exceed: 100 percent for the period one to three months from and after the hedging agreement transaction date, 66⅔ percent for the period four to 18 months from and after the hedging agreement transaction date and 33⅓ percent for the period 19 to 36 months from and after the hedging agreement transaction date. Additionally, at no time will any hedging agreement of any nature have a counterparty with a minimum long-term senior unsecured indebtedness rating less than "BBB+" by Standard & Poors Corporation or "Baa1" by Moody's Investors Services, Inc. at the time that such counterparty entered into the relevant transaction under such hedging agreement and at no time will exposure to any single counterparty exceed 25 percent of the estimated twelve-month production volumes from total proved reserves.

At December 31, 2001, the Company was in compliance with the covenants and had no outstanding borrowings under the Credit Facility. As of March 7, 2002, the Company had outstanding borrowings of $21.0 million under the Credit Facility.

4. SEISMIC DATA AGREEMENT:

The Company and PGS entered into a seismic data agreement ("Data Agreement") dated December 20, 1996, whereby PGS agreed to transfer to Spinnaker certain rights to 3-D seismic data in consideration of Spinnaker equity. The Company accounted for the contribution of the Data Agreement at PGS' cost, which was immaterial.

The Company has agreed to purchase $2.0 million of seismic related services from PGS prior to December 31, 2002. The Company paid to PGS approximately $397,000, $449,000 and $318,000 in 2001, 2000 and 1999, respectively, for seismic-related services. Through December 31, 2001, the Company has paid PGS a total of approximately $1.3 million for seismic-related services. The Company expects to purchase additional seismic-related services for the remaining commitment under the Data Agreement during 2002.

The Data Agreement was amended effective June 30, 1999. The amended Data Agreement modified the amount, type and geographic coverage of the data and related information made available to Spinnaker. In exchange for the amended rights under the Data Agreement, Spinnaker issued to PGS an additional 1,000,000 shares of Common Stock. This transaction was accounted for at PGS' cost of $2.9 million, pursuant to Staff Accounting Bulletin No. 48.

5. EQUITY:

Prior to Spinnaker's initial public offering in September 1999, the Company sold Preferred Stock to various investors. On September 28, 1999, the Company priced its initial public offering of 8,000,000 shares of Common Stock and commenced trading the following day. In connection with the initial public offering, the Company converted all outstanding Preferred Stock into 6,061,840 shares of Common Stock, and certain shareholders reinvested preferred dividends payable of $16.3 million into 1,200,248 shares of Common Stock. On August 16, 2000, the Company completed a public offering of 5,600,000 shares of Common Stock at $26.25 per share. After payment of underwriting discounts and commissions, the Company received net proceeds of $138.9 million. On December 20, 2000, PGS sold its 5,388,743 shares of Common Stock at $29.25 per share. Spinnaker received no proceeds from this sale.

On August 31, 1999, the Company approved a two-for-one stock split on the Common Stock effective September 1, 1999. One additional share was issued for each share of Common Stock. Par value remained unchanged at $0.01 per share. In connection with the Stock Split, the Company amended the certificate of incorporation to increase the authorized number of shares of Common Stock to 50,000,000 shares.

Spinnaker has an effective shelf registration statement relating to the potential public offer and sale by the Company or certain affiliates of up to $300.0 million of any combination of debt securities, preferred stock, common stock, warrants, stock purchase contracts and trust preferred securities from time to time. The registration statement does not provide assurance that the Company will or could sell any such securities.

6. STOCK PLANS:

At December 31, 2001, officers, directors and employees had been granted options to purchase Common Stock under stock plans adopted in 1998, 1999, 2000 and 2001. The exercise price of each option equals the market price of Spinnaker's Common Stock on the date of grant. Stock option grants generally vest ratably over four years, with 20 percent vesting on the date of grant and 20 percent vesting in each of the succeeding four years, and expire after ten years. In the event of certain significant changes in control of the Company, all options then outstanding generally will become immediately exercisable in full.

In January 1998, the stockholders approved the 1998 Stock Option Plan ("1998 Plan"). The 1998 Plan was amended and restated in September 1999 and authorized the issuance of 2,673,242 shares of Common Stock. In September 1999, the stockholders approved the 1999 Stock Incentive Plan ("1999 Plan"). The number of shares of Common Stock that may be issued under the 1999 Plan may not exceed 1,300,000 shares. The maximum number of shares of Common Stock that may be subject to awards granted under the 1999 Plan to any one individual during any calendar year may not exceed 300,000. In connection with the 1999 Plan, the stockholders approved the Adjunct Stock Option Plan ("Adjunct Plan"). The number of shares of Common Stock that may be issued under the Adjunct Plan may not exceed 21,920. In November 2000, the board of directors adopted the 2000 Stock Option Plan ("2000 Plan"). Stockholder approval was not required for the 2000 Plan. The number of shares of Common Stock that may be issued under the 2000 Plan may not exceed 500,000 shares. In May 2001, the stockholders approved the 2001 Stock Incentive Plan ("2001 Plan"). The number of shares of Common Stock that may be issued under the 2001 Plan may not exceed 1,500,000 shares.

The Company applies APB Opinion No. 25 and related interpretations in accounting for its employee stock-based compensation. In accordance with APB Opinion No. 25, compensation expense related to stock-based compensation included in general and administrative expense was approximately $114,000, $158,000 and $150,000 in 2001, 2000 and 1999, respectively. Had compensation cost for the Company's stock option compensation plans been determined based on the fair value at the grant dates for awards under these plans consistent with the method of SFAS No. 123, "Accounting for Stock-Based Compensation," the Company's pro forma net income (loss) available to common stockholders and pro forma net income (loss) per common share would have been as follows (in thousands, except per share amounts):

For the Year Ended December 31,	2001	2000	1999
Pro forma net income (loss) available to common stockholders	$ 57,379	$ 35,543	$ (10,950)
Pro forma net income (loss) per common share:			
Basic	$ 2.12	$ 1.57	$ (1.31)
Diluted	$ 2.02	$ 1.48	$ (1.31)

For purposes of the SFAS No. 123 disclosure, the fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model with assumptions for grants in 2001, 2000 and 1999 as follows:

For the Year Ended December 31,	2001	2000	1999
Risk-free interest rate	4.85% - 5.57%	5.14% - 6.82%	4.67% - 6.08%
Volatility factor	43.0%	42.5%	54.8%
Dividend yield	0%	0%	0%
Expected life of the options (years)	4	4	4.5

Presented below is a summary of stock option activity.

	2001		2000		1999	
	Shares Under Option	Weighted Average Exercise Price	Shares Under Option	Weighted Average Exercise Price	Shares Under Option	Weighted Average Exercise Price
Outstanding, beginning of year	3,718,886	$ 13.80	3,382,974	$ 10.56	2,526,880	$ 9.11
Granted	1,242,800	37.90	802,470	23.45	866,574	14.74
Exercised	(810,991)	8.82	(466,558)	6.88	(5,872)	4.97
Forfeited	(88,139)	17.57	—	—	(4,608)	9.29
Outstanding, end of year	4,062,556	22.08	3,718,886	13.80	3,382,974	10.56
Exercisable, end of year	2,273,548	16.16	2,364,270	11.38	1,919,019	9.62
Available for grant, end of year	648,545		303,206		605,676	
Weighted average fair value of options granted during the year	$ 23.76		$ 15.17		$ 6.78	

The Company transferred treasury shares to certain employees in connection with their exercises of 2,128 and 4,080 options in 2001 and 2000, respectively. Options to purchase 640 shares of Common Stock forfeited during 1999 are not available for future grants.

At December 31, 2001, the following options were outstanding and exercisable and had the indicated weighted average remaining contractual lives:

	Outstanding		Exercisable		
Range of Exercise Prices Per Share	Number of Options	Weighted Average Exercise Price Per Share	Number of Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Life (Years)
\$2.50 – \$5.00	626,824	\$ 4.94	602,272	\$ 4.95	5.2
\$14.50 – \$16.13	1,785,312	15.37	1,256,598	15.39	6.7
\$22.25 – \$31.69	367,420	27.79	134,838	27.61	9.0
\$37.55 – \$41.73	1,283,000	38.17	279,840	38.21	9.2
	4,062,556		2,273,548		

Prior to July 1999, the stock option agreements of two of the Company's officers provided that they could elect to have the Company deliver shares equal to the appreciation in the value of the stock over the option price in lieu of purchasing the amount of shares under option. Based on management's estimate of the share value of the Company, compensation expense of approximately \$1.7 million was recorded in 1999 related to the stock appreciation rights of the stock option agreements. In July 1999, these two officers agreed to eliminate the stock appreciation rights feature of their stock option agreements.

7. EARNINGS PER SHARE:

Basic and diluted net income (loss) per common share is computed based on the following information (in thousands, except per share amounts):

For the Year Ended December 31,	2001	2000	1999
Numerator:			
Net income (loss) available to common stockholders	\$ 66,226	\$ 38,566	\$ (9,248)
Denominator:			
Basic weighted average number of shares	27,079	22,679	8,355
Dilutive securities:			
Stock options	1,281	1,332	—
Diluted adjusted weighted average number of shares and assumed conversions	28,360	24,011	8,355
Net income (loss) per common share:			
Basic:			
Income (loss) before cumulative effect of change in accounting principle	\$ 2.45	\$ 1.70	\$ (1.06)
Cumulative effect of change in accounting principle	—	—	(0.05)
Net income (loss) per common share	\$ 2.45	\$ 1.70	\$ (1.11)
Diluted:			
Income (loss) before cumulative effect of change in accounting principle	\$ 2.34	\$ 1.61	\$ (1.06)
Cumulative effect of change in accounting principle	—	—	(0.05)
Net income (loss) per common share	\$ 2.34	\$ 1.61	\$ (1.11)

For purposes of the diluted earnings per share calculations in 2001 and 2000, certain stock options that could potentially dilute earnings per share are excluded as they were anti-dilutive. In addition, the Preferred Stock and stock options are considered anti-dilutive in 1999 and not considered in the calculations.

8. MAJOR CUSTOMERS:

The Company had natural gas and oil sales to four customers accounting for approximately 32 percent, 23 percent, 21 percent and 17 percent, respectively, of total natural gas and oil revenues, excluding the effects of hedging activities, for the year ended December 31, 2001. The Company had natural gas and oil sales to three customers accounting for approximately 61 percent, 11 percent and 11 percent, respectively, of total natural gas and oil revenues, excluding the effects of hedging activities, for the year ended December 31, 2000. The Company had natural gas and oil sales to two customers accounting for 68 percent and 32 percent, respectively, of total natural gas and oil revenues, excluding the effects of hedging activities, for the year ended December 31, 1999. One of the customers in 2001 and 2000 was Enron North America Corp. Spinnaker no longer sells its natural gas and oil production to this customer.

9. RELATED-PARTY TRANSACTIONS:

The Company paid PGS approximately $397,000, $449,000 and $318,000 in 2001, 2000 and 1999, respectively, for seismic-related services.

The Company paid $17.4 million in 2001 to affiliates of Baker Hughes Incorporated ("Baker Hughes"), an oilfield services company. Mr. Michael E. Wiley, a director of Spinnaker, serves as Chairman of the Board, Chief Executive Officer and President of Baker Hughes. The Company paid $83,000 and $528,000 in 2001 and 2000, respectively, to Cooper Cameron Corporation ("Cooper Cameron"), an oilfield services company. Mr. Sheldon R. Erikson, a director of Spinnaker, serves as Chairman of the Board, Chief Executive Officer and President of Cooper Cameron. The Company purchases oilfield goods, equipment and services from Baker Hughes, Cooper Cameron and other companies in the ordinary course of business. Spinnaker believes that these transactions are at arms-length and the charges and fees that it pays for such goods, equipment and services are competitive with the charges and fees of other companies providing oilfield goods, equipment and services to the oil and gas exploration and production industry.

The Data Agreement was amended effective June 30, 1999. In exchange for the amended rights under the Data Agreement, Spinnaker issued 1,000,000 shares of Common Stock to PGS. See Note 4.

From September 30, 1998 through October 4, 1999, PGS and Warburg provided certain guarantees for the Credit Agreement totaling $75.0 million. See Note 3.

10. INCOME TAXES:

As of December 31, 2001, the Company had approximately $162.2 million of net operating loss carryforwards, of which $23.0 million, $30.2 million, $39.5 million and $69.5 million expire in 2018, 2019, 2020 and 2021, respectively.

The significant items giving rise to the deferred income tax assets and liabilities are as follows (in thousands):

As of December 31,	2001	2000
Deferred income tax liabilities:		
Basis differences in natural gas and oil properties	$ 104,141	$ 50,925
Hedging activities	7,812	—
Total deferred income tax liabilities	111,953	50,925
Deferred income tax assets:		
Net operating losses	$ 58,400	$ 32,836
Other	622	932
Total deferred income tax assets	59,022	33,768
Net deferred income tax liabilities	$ 52,931	$ 17,157

Tax benefits of $9.0 million and $3.7 million associated with the exercise of non-qualified stock options during the years ended December 31, 2001 and 2000 are reflected as a component of equity. The deferred income tax liability includes $7.8 million related to the tax effect of the fair market value of derivatives at December 31, 2001 as required by SFAS No. 133, as amended.

Significant components of the provision for income taxes are as follows (in thousands):

For the Year Ended December 31,	2001	2000	1999
Current	$ 275	$ 25	$ —
Deferred	36,977	20,833	—
Total provision	$ 37,252	$ 20,858	$ —

The differences between the provision for income taxes and the amount that would be determined by applying the statutory federal income tax rate of 35 percent to the income (loss) before income taxes are as follows (in thousands):

For the Year Ended December 31,	2001	2000	1999
Federal income tax expense (benefit) at statutory rates	$ 36,217	$ 20,798	$ (468)
Non-deductible expenses and other	1,035	659	601
Valuation allowance	—	(599)	(133)
Total provision	$ 37,252	$ 20,858	$ —

No net income tax benefit was recognized in 1999 due to the uncertainty of future realization as the Company had not established a history of net operating income.

11. COMMITMENTS AND CONTINGENCIES:

The Company is, from time to time, party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on the financial position, results of operations or cash flows of the Company.

DATA AGREEMENT

The Company has agreed to purchase $2.0 million of seismic-related services from PGS prior to December 31, 2002. Through December 31, 2001, the Company paid PGS a total of approximately $1.3 million for these services.

EMPLOYMENT CONTRACTS

The Company has employment contracts with certain of its executive officers. These contracts provide for annual base salaries, bonus compensation, various benefits and the continuation of salary and benefits for the respective terms of the agreements in the event of termination of employment for various reasons, and whether by the Company or the employee. These agreements are subject to automatic annual extensions unless terminated.

EMPLOYEE 401(K) RETIREMENT PLAN

In July 1998, the Company instituted a 401(k) retirement and profit sharing plan ("401(k) Plan") for its employees. The 401(k) Plan provides that all qualified employees may defer the maximum income allowed under current tax law. The 401(k) Plan covers all employees at least 21 years of age who have completed at least six months of service subsequent to employment.

Effective January 1, 2000, the Company began matching employee contributions to the 401(k) Plan. The Company matches 100 percent of each participant's contributions up to six percent of the participant's annual base salary. In connection with the employer match, the Company issued 5,456 shares of Common Stock valued at $216,000 in 2001 and 5,923 shares of Common Stock valued at $148,000 in 2000.

LEASES

The Company leases administrative offices under non-cancelable operating leases expiring in 2007. Certain of the lease agreements require that the Company pay for utilities, maintenance and other operational expenses of the building. Additionally, the leases contain escalation clauses. The Company also leases office equipment and oil and gas equipment under non-cancelable operating leases. Rental expense was $700,000, $476,000 and $319,000 in 2001, 2000 and 1999, respectively. Minimum future obligations under non-cancelable operating leases at December 31, 2001 for the following five years are $1.2 million, $1.3 million, $1.3 million, $1.3 million and $1.8 million, respectively.

SUMMARY OF CONTRACTUAL OBLIGATIONS

The Company had no debt or capital leases outstanding as of December 31, 2001. The Company has incurred obligations in the ordinary course of business under purchase and service agreements which are not included in the table below. Obligations under operating leases and the Data Agreement as of December 31, 2001 are as follows:

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Operating leases	$ 6,914	$ 1,222	$ 3,858	$ 1,834	$ —
Unconditional Data Agreement obligations	655	655	—	—	—
Total	$ 7,569	$ 1,877	$ 3,858	$ 1,834	$ —

12. COMMODITY PRICE RISK MANAGEMENT ACTIVITIES:

The Company enters into New York Mercantile Exchange ("NYMEX") related swap contracts and collar arrangements from time to time. The Company's swap contracts will settle based on the reported settlement price on the NYMEX for the last trading day of each month for natural gas. In a swap transaction, the counterparty is required to make a payment to the Company for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. The Company is required to make a payment to the counterparty for the difference between the fixed price and the settlement price if the settlement price is above the fixed price. Some of the master agreements require the Company to make margin payments to counterparties when net exposure exceeds a certain threshold. As of March 7, 2002, Spinnaker's commodity price risk management positions in fixed price natural gas swap contracts were as follows:

Period	Average Daily Volume (MMBtu)	Weighted Average Price Per MMBtu
First Quarter 2002	100,000	$ 3.23
Second Quarter 2002	93,407	3.20
Third Quarter 2002	80,000	3.37
Fourth Quarter 2002	76,685	3.58
Full Year 2003	25,000	3.27

Based upon the Company's assessment of its derivative contracts at December 31, 2001, it reported (i) a net current asset of $20.6 million and a noncurrent asset of $1.7 million and (ii) accumulated other comprehensive income of $14.5 million, net of income taxes of $7.8 million. The Company recognized no ineffective component of the derivatives in earnings in 2001. In connection with monthly settlements, the Company recognized net hedging losses of $9.6 million in revenues in 2001. Based on future natural gas prices as of December 31, 2001, the Company would reclassify $20.6 million from accumulated other comprehensive income to earnings within the next 12 months. The amounts ultimately reclassified into earnings will vary due to changes in the fair value of the open derivative contracts prior to settlement.

13. QUARTERLY FINANCIAL DATA (UNAUDITED):

Quarterly operating results for the years ended December 31, 2001 and 2000 are summarized as follows (in thousands, except per share amounts):

For the Quarter Ended (Unaudited)	March 31,	June 30,	September 30,	December 31,
2001:				
Revenues	$ 67,453	$ 59,500	$ 44,818	$ 38,605
Income from operations	42,792	32,886	16,150	8,457
Net income	28,148	21,781	10,803	5,494
Net income per common share:				
Basic	$ 1.05	$ 0.80	$ 0.40	$ 0.20
Diluted	$ 1.00	$ 0.77	$ 0.38	$ 0.19
2000:				
Revenues	$ 13,867	$ 19,145	$ 29,755	$ 58,616
Income from operations	2,926	5,323	13,356	35,659
Net income	3,086	5,239	8,229	22,012
Net income per common share:				
Basic	$ 0.15	$ 0.26	$ 0.35	$ 0.84
Diluted	$ 0.15	$ 0.24	$ 0.33	$ 0.79

The Company had in place both financial hedge and physical contracts with Enron North America Corp. at the time it filed for bankruptcy in December 2001. Spinnaker did not receive payment for fixed price swap contracts intended to hedge December 2001 natural gas sales and November 2001 natural gas production sold to Enron entities. The Company recorded a net reserve of $3.1 million in the fourth quarter of 2001 related to these receivables and has no other exposure to Enron Corp. and its subsidiaries.

14. SUPPLEMENTARY FINANCIAL INFORMATION ON NATURAL GAS AND OIL EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED):

The following tables set forth certain historical costs and operating information related to the Company's natural gas and oil producing activities.

CAPITALIZED COSTS AND COSTS INCURRED

Capitalized costs and costs incurred related to natural gas and oil producing activities are summarized below (in thousands):

As of December 31,	2001	2000
Capitalized costs:		
Proved properties	$ 575,806	$ 293,002
Unproved properties not being amortized	102,881	83,165
Total	678,687	376,167
Accumulated depreciation, depletion and amortization	(158,746)	(73,687)
Net capitalized costs	$ 519,941	$ 302,480

Depreciation, depletion and amortization per Mcfe was $1.60, $1.57 and $1.59 in 2001, 2000 and 1999, respectively.

COSTS INCURRED IN OIL AND NATURAL GAS PROPERTY ACQUISITION, EXPLORATION AND DEVELOPMENT ACTIVITIES

Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include the costs of drilling exploratory wells, including those in progress, geological and geophysical service costs and depreciation of support equipment used in exploration activities. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs incurred in oil and natural gas property acquisition, exploration and development activities are as follows (in thousands):

For the Year Ended December 31,	2001	2000	1999
Acquisition costs:			
Unproved	$ 34,524	$ 21,421	$ 13,911
Proved	—	—	—
Exploration costs	192,114	121,451	45,152
Development costs	75,882	51,144	23,614
Total costs incurred	$302,520	$194,016	$ 82,677

ESTIMATES OF PROVED NATURAL GAS AND OIL RESERVES

Proved natural gas and oil reserve quantities and the related discounted future net cash flows before income taxes are based on estimates prepared by Ryder Scott Company, L.P., independent petroleum consultants. Such estimates have been prepared in accordance with guidelines established by the Commission.

Proved reserves are estimated quantities of natural gas and oil 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 developed reserves are proved reserves that can reasonably be expected to be recovered through existing wells with existing equipment and operating methods.

The Company's net ownership in estimated quantities of proved natural gas and oil reserves and changes in net proved reserves, all of which are located in the Gulf of Mexico, are as follows:

	Natural Gas (MMcf)	Oil and Condensate (MBbls)	Natural Gas Equivalents (MMcfe)
Proved reserves as of December 31, 1998	50,946	470	53,766
Extensions, discoveries and other additions	43,270	2,039	55,505
Revisions of previous estimates	7,776	83	8,274
Production	(11,962)	(180)	(13,044)
Proved reserves as of December 31, 1999	90,030	2,412	104,501
Extensions, discoveries and other additions	97,665	1,027	103,829
Revisions of previous estimates	5,248	(116)	4,552
Production	(28,845)	(225)	(30,194)
Proved reserves as of December 31, 2000	164,098	3,098	182,688
Extensions, discoveries and other additions	74,531	18,921	188,057
Revisions of previous estimates	(11,414)	2,829	5,556
Production	(51,234)	(310)	(53,094)
Proved reserves as of December 31, 2001 [1]	175,981	24,538	323,207
Proved developed reserves:			
December 31, 1998	30,806	318	32,715
December 31, 1999	50,756	384	53,062
December 31, 2000	112,315	1,042	118,568
December 31, 2001 [1]	82,221	748	86,711

[1] During 2001, Spinnaker participated in a significant deep water oil discovery on Green Canyon Blocks 338/339 ("Front Runner") with a 25 percent non-operator working interest. The Company participated in five consecutive successful wells and sidetracks in testing the reservoirs on these blocks. This significant oil discovery has changed Spinnaker's reserve profile. Proved oil and condensate reserves were 46 percent of total proved reserves at December 31, 2001 compared to 10 percent at December 31, 2000. Of the Company's total proved reserves as of December 31, 2001, 73 percent were proved undeveloped reserves. Front Runner represented more than 50 percent of total proved undeveloped reserves.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

- Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year-end economic conditions.
- The estimated future gross revenues of proved reserves are priced on the basis of year-end market prices.
- The future gross revenue streams are reduced by estimated future costs to develop and to produce the proved reserves, as well as certain abandonment costs based on year-end cost estimates and the estimated effect of future income taxes.
- Future income taxes are computed by applying the statutory tax rate to future net cash flows reduced by the tax basis of the properties, the estimated permanent differences applicable to future natural gas and oil producing activities and tax carryforwards.

The standardized measure of discounted future net cash flows is not intended to present the fair market value of the Company's natural gas and oil reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves in excess of proved reserves, anticipated future changes in prices and costs, an allowance for return on investment and the risks inherent in reserve estimates. Given the volatility of natural gas and oil prices, it is reasonably possible that the Company's estimate of discounted future net cash flows from proved natural gas and oil reserves will change in the near term. If natural gas and oil prices decline, even if for only a short period of time, or if the Company has significant downward revisions to its estimated proved reserves, it is possible that write-downs of natural gas and oil properties could occur in the future. The standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves is as follows (in thousands):

For the Year Ended December 31,	2001	2000	1999
Future cash inflows [1]	$ 944,861	$ 1,730,754	$ 275,539
Future operating expenses	(164,105)	(60,259)	(36,396)
Future development costs	(191,711)	(68,929)	(48,717)
Future net cash flows before income taxes	589,045	1,601,566	190,426
Future income taxes [2]	(120,489)	(516,488)	—
Future net cash flows	468,556	1,085,078	190,426
10 percent annual discount	(139,000)	(185,941)	(38,862)
Standardized measure of discounted future net cash flows	$ 329,556	$ 899,137	$ 151,564

[1] Weighted average market prices for natural gas and oil used to calculate future cash inflows were $2.71, $9.99 and $2.37 per Mcf of natural gas and $19.23, $30.41 and $25.70 per barrel of oil in 2001, 2000 and 1999, respectively.

[2] Net operating loss carryforwards and basis in natural gas and oil properties eliminated the need for future income taxes in 1999.

The primary sources of change in the standardized measure of discounted future net cash flows are as follows (in thousands):

For the Year Ended December 31,	2001	2000	1999
Standardized measure, beginning of year	$ 899,137	$ 151,564	$ 52,109
Extensions and discoveries, net of related costs	198,709	719,694	75,572
Sales of natural gas and oil produced, net of production costs	(207,824)	(131,030)	(28,097)
Net changes in prices and production costs	(958,755)	486,496	22,869
Change in future development costs	(18,959)	(3,501)	(1,957)
Development costs incurred during the period that reduced future development costs	47,463	37,851	14,494
Revisions of quantity estimates	6,092	34,749	13,624
Accretion of discount	132,067	15,156	5,211
Net change in income taxes	335,952	(421,535)	—
Change in production rates and other	(104,326)	9,693	(2,261)
Standardized measure, end of year	$ 329,556	$ 899,137	$ 151,564

Selected Financial Data

The following table sets forth some of the Company's historical consolidated financial data. The following data should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and Notes thereto included elsewhere herein. The selected consolidated financial data provided below are not necessarily indicative of the future results of operations or financial performance of the Company.

Year Ended December 31, (in thousands, except per share data)	2001	2000	1999	1998	1997
STATEMENT OF OPERATIONS DATA:					
Revenues	$ 210,376	$ 121,383	$ 34,258	$ 3,298	$ 201
Expenses:					
Lease operating expenses	12,132	9,009	5,411	474	72
Depreciation, depletion and amortization — natural gas and oil properties	85,059	47,451	20,788	2,738	68
Depreciation and amortization — other	398	309	213	437	349
Write-down of natural gas and oil properties [1]	—	—	—	2,642	—
General and administrative	9,443	7,350	4,860	3,809	1,965
Charges related to Enron bankruptcy [2]	3,059	—	—	—	—
Stock appreciation rights expense [3]	—	—	1,651	—	—
Total expenses	110,091	64,119	32,923	10,100	2,454
Income (loss) from operations	100,285	57,264	1,335	(6,802)	(2,253)
Other income (expense):					
Interest income	3,574	2,908	528	221	91
Interest expense, net	(381)	(748)	(2,805)	(279)	—
Total other income (expense)	3,193	2,160	(2,277)	(58)	91
Income (loss) before income taxes	103,478	59,424	(942)	(6,860)	(2,162)
Income tax provision	37,252	20,858	—	—	—
Income (loss) before cumulative effect of change in accounting principle	66,226	38,566	(942)	(6,860)	(2,162)
Cumulative effect of change in accounting principle [4]	—	—	(395)	—	—
Net income (loss)	66,226	38,566	(1,337)	(6,860)	(2,162)
Accrual of dividends on preferred stock	—	—	(7,911)	(7,094)	(1,326)
Net income (loss) available to common stockholders	$ 66,226	$ 38,566	$ (9,248)	$ (13,954)	$ (3,488)
Basic income (loss) per common share: [5] [6]					
Income (loss) before cumulative effect of change in accounting principle	$ 2.45	$ 1.70	$ (1.06)	$ (3.44)	$ (0.88)
Cumulative effect of change in accounting principle [4]	—	—	(0.05)	—	—
Net income (loss) per common share	$ 2.45	$ 1.70	$ (1.11)	$ (3.44)	$ (0.88)
Diluted income (loss) per common share: [5] [6]					
Income (loss) before cumulative effect of change in accounting principle	$ 2.34	$ 1.61	$ (1.06)	$ (3.44)	$ (0.88)
Cumulative effect of change in accounting principle [4]	—	—	(0.05)	—	—
Net income (loss) per common share	$ 2.34	$ 1.61	$ (1.11)	$ (3.44)	$ (0.88)
Weighted average number of common shares outstanding: [5] [6]					
Basic	27,079	22,679	8,355	4,059	3,960
Diluted	28,360	24,011	8,355	4,059	3,960

Selected Financial Data

Year Ended December 31, (in thousands)	2001	2000	1999	1998	1997
SUMMARY BALANCE SHEET DATA:					
Working capital (deficit)	$ (20,654)	$ 74,005	$ 19,675	$ (30,641)	$ 4,252
Property and equipment, net	522,573	304,381	157,397	95,607	15,452
Total assets	587,316	442,704	189,553	102,769	22,358
Short-term debt	—	—	—	19,000	—
Accrued preferred dividends payable [6]	—	—	—	8,478	1,383
Total equity [6]	458,492	361,259	177,102	56,913	18,879

[1] At December 31, 1998, the Company recognized a non-cash write-down of natural gas and oil properties in the amount of approximately $2.6 million in connection with the ceiling limitation required by the full cost method of accounting for natural gas and oil properties. The write-down was primarily the result of the decline in natural gas prices experienced in 1998 and through April 9, 1999. As permitted by applicable Commission rules, in calculating the amount of the write-down, the Company used post year-end natural gas and oil price increases of $0.26 per MMBtu of natural gas and $4.52 per barrel of oil from December 31, 1998 to April 9, 1999. If the Company had used only December 31, 1998 natural gas and oil prices, it would have recognized a total non-cash write-down of natural gas and oil properties of approximately $13.0 million.

[2] The Company had in place both financial hedge and physical contracts with Enron North America Corp. at the time it filed for bankruptcy in December 2001. Spinnaker did not receive payment for fixed price swap contracts totaling $2.1 million, intended to hedge December 2001 natural gas sales, and $1.4 million related to November 2001 natural gas production sold to Enron entities. The Company recorded a net reserve of $3.1 million against these receivables and has no other exposure to Enron Corp. and its subsidiaries.

[3] Prior to July 1999, the stock option agreements of two of the Company's officers provided that they could elect to have Spinnaker deliver shares equal to the appreciation in the value of the stock over the option price in lieu of purchasing the amount of shares under option. Based on management's estimate of the share value of Spinnaker, the Company recorded compensation expense of approximately $1.7 million in 1999 related to the stock appreciation rights of the stock option agreements. In July 1999, these two officers agreed to eliminate the stock appreciation rights feature of their stock option agreements.

[4] The cumulative effect of change in accounting principle represents the adoption of Statement of Position 98-5 "Reporting on the Costs of Start-Up Activities."

[5] Spinnaker was originally formed as a limited liability company, and the Company issued common units and preferred units. In connection with its conversion to a corporation in January 1998, the Company exchanged Common Stock for all then outstanding common units and Preferred Stock for all then outstanding preferred units. The Company expresses all historical unit data in shares of Common Stock.

[6] In connection with the initial public offering, the Company issued 8,000,000 shares of Common Stock, converted all then outstanding shares of Preferred Stock into 6,061,840 shares of Common Stock and issued 1,200,248 shares of Common Stock to certain holders of the previously outstanding Preferred Stock in lieu of payment of accrued cash dividends. On August 16, 2000, the Company completed a public offering of 5,600,000 shares of Common Stock.

Directors and Officers

BOARD OF DIRECTORS

Roger L. Jarvis
Chairman of the Board, President and Chief Executive Officer
Spinnaker Exploration Company

Sheldon R. Erikson [2]
Chairman of the Board, President and Chief Executive Officer
Cooper Cameron Corporation

Jeffrey A. Harris [2] *
Senior Managing Director / Partner
Warburg Pincus LLC / Warburg Pincus & Co.

Michael E. McMahon [1] *
Partner
RockPort Partners LLC

Michael G. Morris [1]
Chairman of the Board, President and Chief Executive Officer
Northeast Utilities

Howard H. Newman
Vice Chairman / Partner
Warburg Pincus LLC / Warburg Pincus & Co.

Michael E. Wiley [1] [2]
Chairman of the Board, President and Chief Executive Officer
Baker Hughes Incorporated

(1) Audit Committee
(2) Compensation Committee
* Committee Chairman

CORPORATE OFFICERS

Roger L. Jarvis
Chairman of the Board, President and Chief Executive Officer

Robert M. Snell
Vice President, Chief Financial Officer and Secretary

William D. Hubbard
Vice President – Exploration

Kelly M. Barnes
Vice President – Land

L. Scott Broussard
Vice President – Drilling and Production

Jimmy W. Bennett
Vice President – Systems Technology and Processing

Jeffrey C. Zaruba
Vice President, Treasurer and Assistant Secretary

Stockholder Information

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TRANSFER AGENT

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350 Indiana Street, Suite 800
Golden, Colorado 80401
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OUTSIDE LEGAL COUNSEL

Vinson & Elkins L.L.P.
Houston, Texas

FORM 10-K AND OTHER REQUESTS

Stockholders may obtain, without charge, a copy of Spinnaker's Form 10-K report as filed with the Securities and Exchange Commission. For copies or other requests, please contact Investor Relations at the corporate address.

MARKET INFORMATION

Spinnaker's common stock began trading on the New York Stock Exchange on July 26, 2000 under the symbol "SKE." Prior to that date, Spinnaker's common stock traded on The Nasdaq National Market under the symbol "SPNX." The following table sets forth the range of high and low sales prices per share of common stock for each calendar quarter.

	Sales Price	
	High	Low
2000:		
First Quarter	$ 25.00	$ 13.25
Second Quarter	$ 30.50	$ 19.50
Third Quarter	$ 42.25	$ 24.03
Fourth Quarter	$ 44.00	$ 24.75
2001:		
First Quarter	$ 44.50	$ 33.00
Second Quarter	$ 48.00	$ 36.60
Third Quarter	$ 43.96	$ 30.00
Fourth Quarter	$ 45.55	$ 33.30
2002:		
First Quarter (through March 7, 2002)	$ 41.87	$ 34.45

As of March 7, 2002, there were 40 holders of record of the Company's common stock.

ANNUAL MEETING

The Company's annual meeting of stockholders will be held at 9:00 a.m. on Tuesday, May 7, 2002, at the DoubleTree Hotel at Allen Center, 400 Dallas Street at Bagby, Houston, Texas.

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