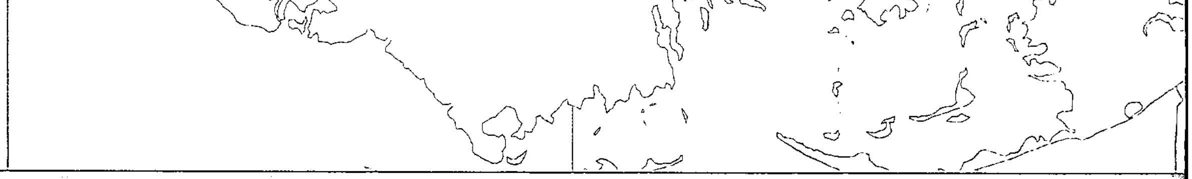


CHARTING A COURSE FOR GROWTH

SPINNAKER EXPLORATION COMPANY **2003** ANNUAL REPORT

GREEN CANYON

CORPORATE PROFILE

Spinnaker Exploration Company ("Spinnaker" or the "Company") is an independent energy company engaged in the exploration, development and production of oil and gas in the U.S. Gulf of Mexico. Formed in December 1996, 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 17,700 blocks of mostly contiguous 3-D seismic data in the Gulf of Mexico. This database covers an area of approximately 45 million acres, which the Company believes is one of the largest 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, 2003, Spinnaker participated in drilling 149 wells, 90 of which were successful. As of December 31, 2003, the Company had estimated proved reserves of 332.6 billion cubic feet of gas equivalent ("Bcfe"), approximately 46% 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."

FRONT COVER: The *Noble Amos Runner* semi-submersible rig drilled our initial deepwater discovery at Front Runner in 2001. Front Runner will commence production in the second half of 2004.

Page 8: Drillship *Deepwater Millenium* photo courtesy of Transocean. Page 10–11: *Cajun Express* photo courtesy of Transocean.

Spinnaker Exploration Company

FINANCIAL HIGHLIGHTS

(thousands of dollars except per share amounts)

For the Year ended December 31,	2003	2002	2001
Revenues	$ 226,850	$ 188,326	$ 210,376
Income from operations	63,160	49,090	100,285
Net income	36,612	31,579	66,226
Net income per common share:			
Basic	1.10	1.00	2.45
Diluted	1.08	0.97	2.34
Cash from operations:			
Net cash provided by operating activities	198,110	153,959	209,437
Changes in operating assets and liabilities	(7,041)	6,476	(20,228)
Cash from operations	191,069	160,435	189,209
Oil and gas capital costs incurred	306,175	342,479	302,520

As of December 31,			
Cash and cash equivalents	$ 15,315	$ 32,543	$ 14,061
Property and equipment, net	939,668	760,854	522,573
Total assets	990,582	842,715	587,316
Long-term debt	50,000	–	–
Equity	744,061	692,977	458,492

Spinnaker Exploration Company

OPERATING HIGHLIGHTS

	2003	2002	2001
Production (MMcfe)	49,010	51,419	53,094
Percent natural gas production	83%	88%	96%
Average realized natural gas price per Mcf [1]	$ 4.53	$ 3.56	$ 3.96
Average realized oil and condensate price per barrel	$ 30.56	$ 26.39	$ 24.90
Proved reserves (MMcfe)	332,581	323,577	323,207
Percent proved natural gas reserves	46%	44%	54%
Present value of future net cash flows (before income taxes) discounted at 10% (in thousands) [2]	$ 1,064,647	$ 847,273	$ 415,139
Lease acreage (net acres, in thousands)	819	742	629
3-D seismic data coverage (millions of acres)	45	40	39

(1) Including the effects of hedging activities

(2) Calculated using prices of $6.29, $4.91 and $2.71 per Mcf of natural gas and $30.34, $30.50 and $19.23 per barrel of oil as of December 31, 2003, 2002 and 2001, respectively

TO OUR SHAREHOLDERS:

It is a pleasure for me to report that Spinnaker Exploration continues to chart a course for growth in the Gulf of Mexico. Our journey remains one focused on building value through exploration for oil and gas in one of the world's most prolific hydrocarbon basins, the Gulf of Mexico.

From a financial perspective, 2003 was a good year as higher commodity prices boosted revenues and income. Operationally, we made significant progress as production began from our first major discovery in the deep waters of the Gulf and the Front Runner facility nears completion. The first test of our inventory in the Eastern Gulf of Mexico – a relatively unexplored area where we are one of the best-positioned smaller players – was positive with a significant natural gas discovery. We also continued to maintain our foundation on the conventional portion of the shelf. At the same time, we extended our search for oil and gas into the deeper areas of the region where greater opportunities lie. As always, our competitive advantage remained the capability of our talented team of individuals to generate high-quality prospects through the interpretation of one of the most extensive datasets available for the Gulf.

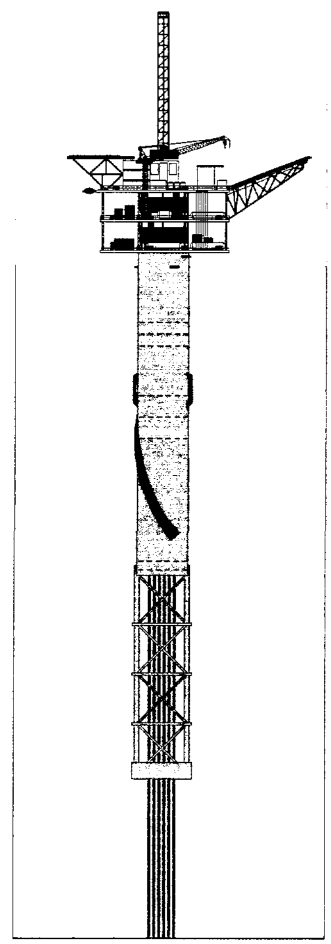
While the Gulf of Mexico is considered by some to be a mature province, it yielded more proved hydrocarbon resources in 2002, as was likely the case again in 2003, than any other basin in the world outside the Middle East. The geology of the Gulf is rich and complex, providing the perfect setting for a company like ours that possesses strength in data integration and seismic image enhancement. With its proximity to stable markets, existing and developing infrastructure, exploratory potential and favorable fiscal regime, the province presents one of the industry's most positive operating environments. We continue to build a portfolio that capitalizes on the diversity of the Gulf – a blend of conventional and deep exploration plays on the shelf – while searching for big field opportunities in the more frontier deepwater areas.

A DIVERSIFIED GULF PORTFOLIO

Our asset base reflects the strategy of diversification. Spinnaker began in 1997 as a conventional shelf player with the concept of exploiting the shallow section of the shelf where advanced completion technologies and economic demands were creating a higher level of profitability. But even then we were generating ideas involving the deep geologic section of the shelf, as well as in the deep water. Our goal was to build a balanced inventory of conventional and deep shelf activities that would provide stable growth and a high rate of return. During the last two years, a large portion of our capital expenditures were allocated to two significant deepwater plays – Front Runner and Zia – and in 2004 we will begin to reap the benefits of the cash flow generated from these two projects.

Our strong position on the shelf has allowed us to make these diversifying investments without compromising balance sheet quality or liquidity, and our balance sheet remains among the "best in class." While we added $50 million of debt during the year, our ability to support that debt level has

BELOW: Front Runner is scheduled to commence production in the second half of 2004. The capacity of the spar production facility is 60,000 barrels of oil per day and 110 MMcf of natural gas per day. Based on this capacity and considering MMS royalty relief on the first 87.5 million barrels, annualized production capability from Front Runner alone is approximately 40 Bcfe, or 82% of total 2003 production.



"While the Gulf of Mexico is considered by some to be a mature province, it yielded more proved hydrocarbon resources in 2002, as was likely the case again in 2003, than any other basin in the world outside the Middle East."

improved substantially with our deepwater production projects. With a new $200 million three-year revolving credit agreement completed in late 2003 and substantial liquidity options still available, Spinnaker remains in a solid position to capitalize on our many portfolio opportunities.

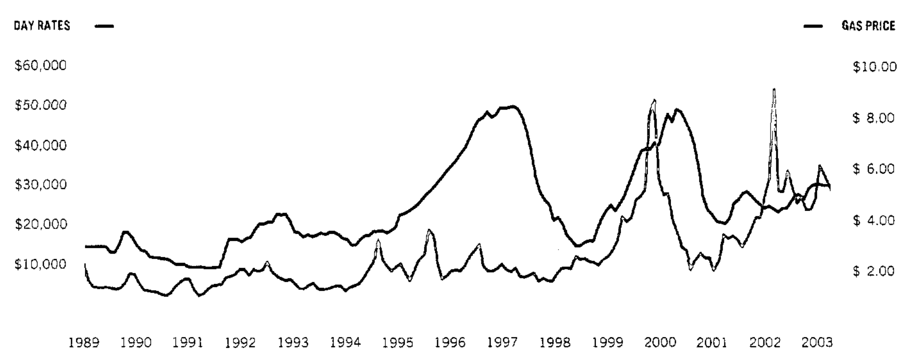
During this period of funding larger projects with longer development cycles, Spinnaker has managed to hold its own and largely maintain its base of production on the shelf. However, this transition did impact our total production volumes in 2003 with a 5% decline from 2002 to 2003. The drop in production volumes from our shelf properties is attributable to a decrease in exploration drilling in 2003 as we focused on our two major deepwater projects. Overall, we spent a total of $105 million on exploratory drilling during the year, or about 38% of our budget. We anticipate that both absolute expenditures as well as percentage allocation dedicated to exploration will be significantly higher in 2004. After all, we are first and foremost an exploration company.

Recently, the cost environment for services related to shelf activities has been particularly attractive. Historically, upward moves in commodity prices have been outpaced by even larger increases in rig rates; however, in the current price cycle, rig rates have been much more stable as hydrocarbon prices have moved higher.

CONTINUING TO EXPLORE THE DEEP SHELF

The shallow water portion of the Gulf now must be viewed as two distinct provinces – shallow and deep. The conventional section is super-mature and likely to yield mainly small gas discoveries and small-to-moderate-sized oilfields. Over the last few years, the combination of technology and reasonably high commodity prices has resulted in a very efficient harvest of likely resource base there. Spinnaker and others will continue to find other fields in this area, but the impact will be small in relative terms. For our part, the conventional shelf will receive diminishing allocation of capital resources, continuing a trend that began in 1998.

JACK-UP DAYRATES AND NATURAL GAS PRICES



Source: Analysts Research, January 2004

SABINE PASS

Spinnaker began in 1997 as a conventional player in the shelf area of the Gulf of Mexico. The Company has expanded its exploratory efforts to the deep shelf that offers greater reserve potential and economic reward.

FACING PAGE TOP RIGHT: Numerous exploratory opportunities have been identified on the 163 leasehold interests that Spinnaker holds on the Gulf of Mexico shelf.

SHELF

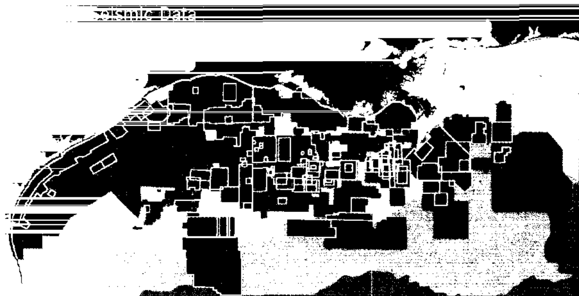
THE CONVENTIONAL SHELF IS SUPER-MATURE AND LIKELY TO YIELD MAINLY SMALL GAS DISCOVERIES AND SMALL-TO-MODERATE-SIZED OILFIELDS. HOWEVER, THE DEEP SHELF OFFERS HIGH POTENTIAL AND SPINNAKER INTENDS TO HAVE CONSTANT, HIGH QUALITY EXPOSURE IN THIS AREA.

GALVESTON

SPINNAKER 3-D SEISMIC DATABASE

Reprocessed Data

Seismic Data



S. ADDN

As of December 31, 2003, Spinnaker held license rights to approximately 17,700 blocks of mostly contiguous 3-D seismic data covering approximately 45 million acres. About one-half of this database has been reprocessed into various pre-stack and post-stack products. Nearly 5,000 blocks of data were reprocessed in the last two years alone.


SHELF PORTFOLIO
Acreage
Spinnaker Discoveries
Owned Prospects
2003–04 Activity

FACING PAGE LOWER LEFT: A team of technical specialists with significant experience in database and systems management, seismic data processing, petrophysical analysis and geologic modeling and inversion is required to develop Spinnaker's exploratory program. They are aided in their efforts with an extensive 3-D seismic database, state-of-the-art computer-aided exploration technology and other technical tools.

The deep shelf, however, has a long way to go. This year, the Minerals Management Service raised its estimation of probable deep shelf resources from 20 Tcf to 55 Tcf of gas. While these are just approximations, the deep shelf is clearly yielding new reserves. Production from this play now accounts for almost 3% of our national supply or about 1.5 Bcf of gas per day. Spinnaker remains one of the most successful players in the province and is involved in approximately 20% of that important new supply resource.

Last year I said that we were likely to increase our holdings in the deep stratigraphic section of the so-called "deep shelf play," and in fact we did, particularly in the Miocene-aged plays of the Central Gulf. We currently have identified about 55 prospects within our inventory of 433,000 gross acres, 331,000 net to Spinnaker. These interests were acquired for their exploration potential. To be successful with the deep shelf play, we believe that sophisticated technology must be applied. Once again, Spinnaker's processing, reservoir characterization and visualization capabilities make us well-suited to the challenge. While technically and operationally demanding, the deep shelf offers high potential and Spinnaker intends to have constant, high quality exposure in this area and will test a number of potential targets in 2004.

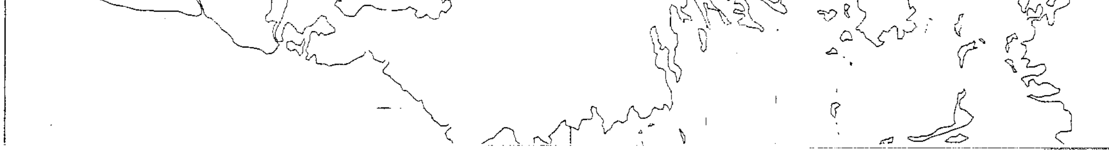
Since entering the deep shelf play six years ago, Spinnaker has drilled or participated in 70 wells with a 57% success rate. This experience has given us considerable engineering and operations expertise in an area that is not easy to drill and somewhat unique because of high pressure and temperature conditions. Our operational capabilities in the deep shelf play were evident in 2003. Two quick turnaround developments were completed for successful wells on High Island Blocks 206 and 47. The latter project involved the drilling and completion of an 18,000-foot well and construction of a platform and pipeline. The entire project was completed within budget in only 101 days from the commencement of exploratory drilling.

THE FOCUS ON THE DEEP WATER FRONTIER

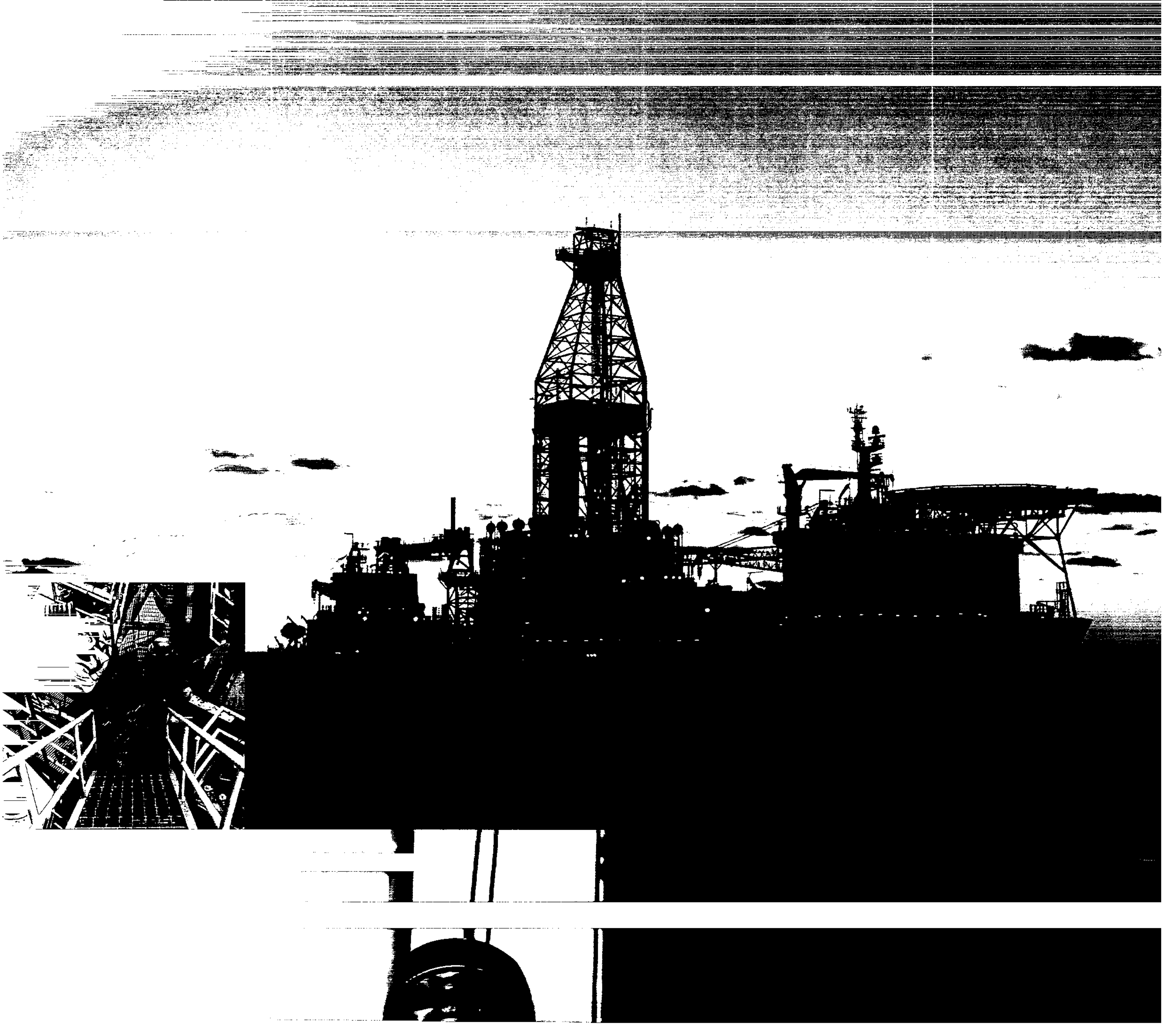
Spinnaker holds approximately 131 blocks covering 745,000 gross acres, or 312,000 net acres, in the deep waters of the Gulf of Mexico. Currently, we have identified about 70 prospects from this inventory. This impressive position has been developed over a three-year period. Since entering the deepwater Gulf, we have been successful in finding hydrocarbons in about two-thirds of our efforts. To date, Spinnaker has discovered 11 new deepwater fields, with two currently producing, four in development and four more still under evaluation.

The importance of our deepwater assets increased significantly during 2003 with the commencement of production from the Zia Field in June and the near completion of our production-related facilities in the Front Runner Field that are slated to begin operations in the second half of 2004. As of December 31, 2003, the Zia Field was producing approximately 5,700 barrels of oil per day

WEST CAMERON



The deep waters of the Gulf of Mexico are becoming an increasingly important part of Spinnaker's source for production and reserve growth. Deepwater assets increased significantly during 2003 with the commencement of production of the Zia Field and will continue to increase in 2004 with the completion of production-related facilities serving the Front Runner Field. An estimated 40% of 2004 exploratory activity will be focused in the deep water.



ANYON

Since 2001, Spinnaker has aggressively sought opportunities in the deep waters of the Gulf of Mexico. Approximately 70% of inception-to-date deepwater drilling activities have occurred in the past three years with historical success rates consistent with Spinnaker's activities on the shelf.

(BOPD) and 7.5 million cubic feet of gas (MMcf) per day. Of that amount, approximately 1,700 BOPD and 2.3 MMcf were net to Spinnaker.

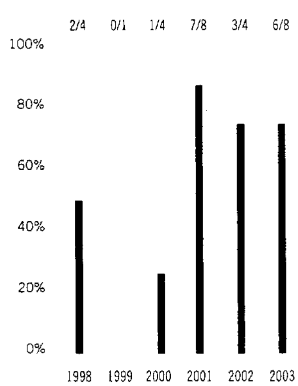
Construction of the Front Runner complex – costing approximately $660 million, or $165 million net to Spinnaker, to build – is now in its final stages. As you can imagine, a project of this scope required a considerable portion of both our human and financial resources. At peak capacity, the field will produce 60,000 BOPD and 110 MMcf per day, with 15,000 BOPD and 27.5 MMcf net to Spinnaker. This asset will become a legacy asset in our portfolio and will significantly contribute to production volumes and influence our historical decline rates. Production is scheduled to commence in the latter half of 2004.

The Zia and Front Runner fields represent the successful execution of our intra-Gulf diversification strategy and will ultimately produce a significant percentage of our overall production volumes. In fact, production from our deepwater discoveries by 2007 is expected to exceed our forecasted 2004 production. This production growth is combined with a significant upside from an exploration perspective. For instance, we own a number of prospects within the immediate Front Runner Field area and several outside of the field, but adjacent to the accumulation. One or two of these prospects are likely to be tested in 2004. If successful, those potential resources might lessen or eliminate production declines from the facility in years 2006 and beyond. At the same time, that incremental investment would have only a fraction of the development burden associated with the original field discoveries, and thus enjoy high rates of return and quick turn-around when successful.

Our deepwater portfolio yielded another milestone in late 2003 when our first successful exploratory well was drilled in the Eastern Gulf. The result was a significant gas discovery at the Amazon/Spiderman prospect. While additional delineation drilling at this site will occur during the first half of 2004, at this time we believe it is the largest find so far in the Eastern Gulf province. The field is clearly economic considering only currently proven resource, and we are already examining a number of development opportunities. Spinnaker and its partners will now test the nearby San Jacinto prospect located six miles west of Amazon/Spiderman that also could represent meaningful new reserves. In addition to these two related areas, we own interests ranging from 20% to 100% in five additional prospects in the Eastern Gulf.

Spinnaker stands to be one of the industry's winners in this new play in the Eastern Gulf. We are especially excited because this area is gas prone, reasonably close to shelf infrastructure and can be developed in a reasonable cycle time. These factors contribute to particularly robust deepwater economics. U.S. natural gas supplies also continue to remain tight and the resource potential could add greatly to meeting the nation's growing demand.

DEEPWATER SUCCESS RATE
(average sucess rate of 66% over *the past six years*)

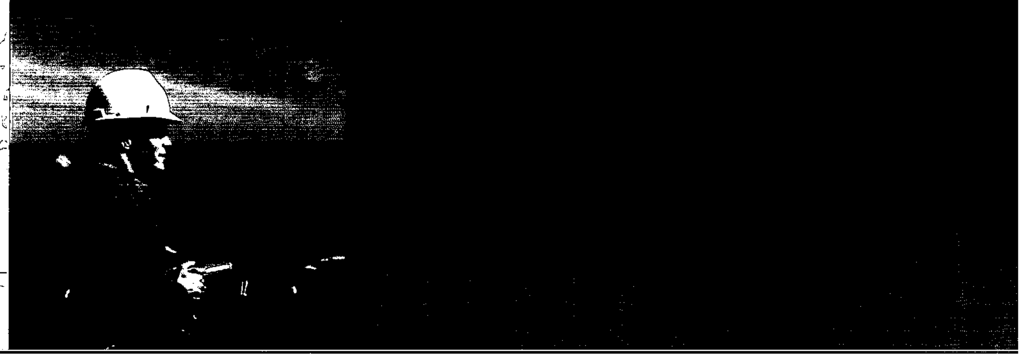


Spinnaker's deepwater portfolio is diversified across more than ten distinct geologic plays and approximately 70 prospect ideas. The Company's ability to upgrade seismic information in an integrated fashion is a key to its ability to compete in these plays.

FACING PAGE TOP RIGHT: Spinnaker held 131 leasehold interests in the deepwater plays of the Gulf of Mexico as of December 31, 2003. These leases cover approximately 745,000 gross acres, or 312,000 net acres.

DEEP WATER

THE DEEP WATER IS IMMATURE AS AN EXPLORATION PROVINCE AND IS CHARACTERIZED BY EXPANDING INFRASTRUCTURE AND LARGE AVERAGE FIELD SIZE. SPINNAKER'S ALLOCATION OF CAPITAL TO DEEPWATER EXPLORATION IS LIKELY TO RISE CONSISTENTLY DURING THE REMAINDER OF THE DECADE.



EASTERN GULF REGIONAL STRUCTURE

Successful Well/Sidetrack

Prospect

Niobrara

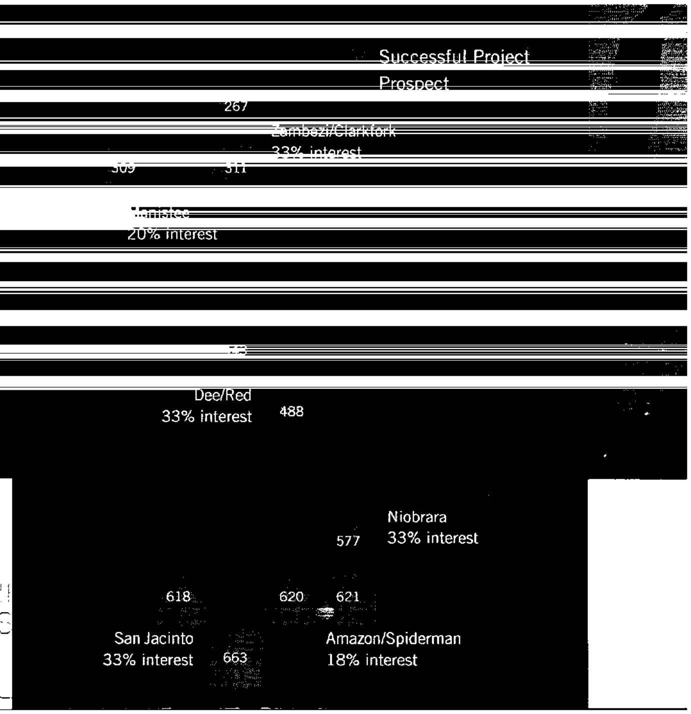
San Jacinto

Amazon/Spiderman

LEFT: During 2003, Spinnaker began exploratory drilling designed to evaluate its holdings in the Eastern Gulf. The result was the largest natural gas discovery thus far in the Eastern Gulf province.

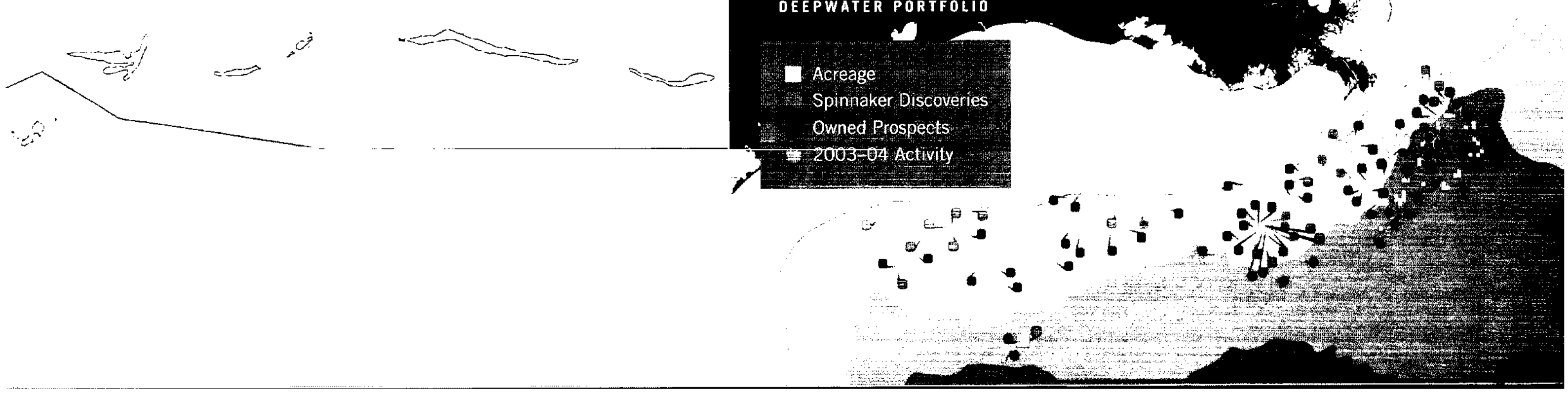
RIGHT: With a minimal capital commitment for leasehold, Spinnaker is one of the best-positioned small- to mid-sized independents in the Eastern Gulf of Mexico.

EASTERN GULF PROSPECT INVENTORY

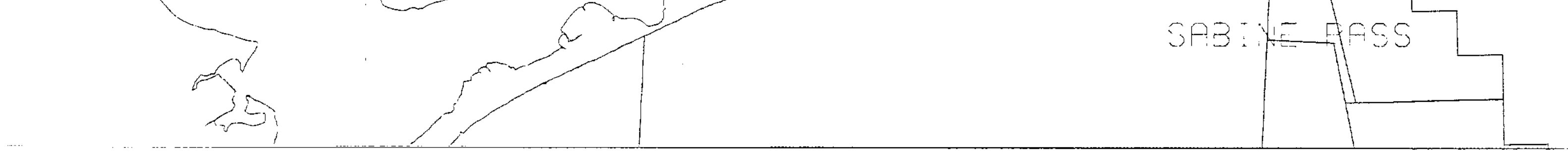


SOUTH TIMBALIER

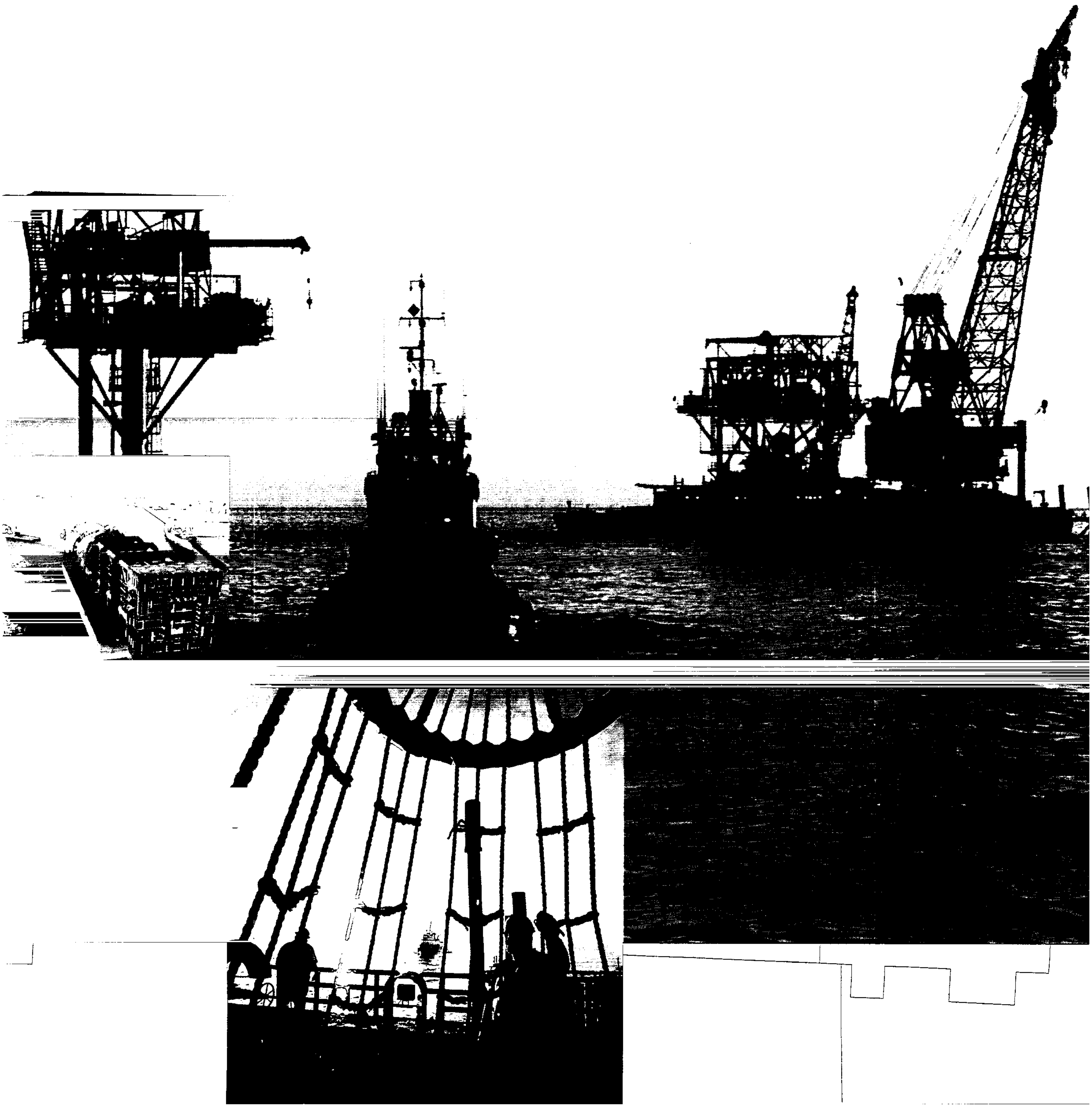
S ADDN



MISSISSIPPI CANYON



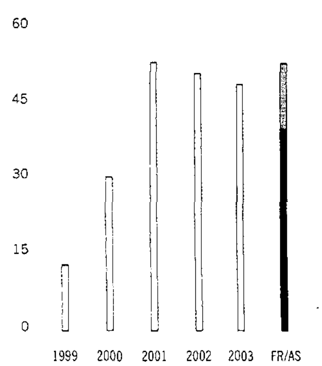
During 2003, Spinnaker demonstrated its capability to quickly capitalize on its success. In only 101 days and within budget, an 18,000-foot well was drilled and a platform and pipeline were constructed at High Island 47. The High Island area exemplifies the potential that remains in what is considered a more developed part of the Gulf.



FACING PAGE FAR LEFT:
The hull portion of the Front Runner production facility arrived outside Pascagoula, Mississippi in early December 2003. The 590-foot load was fabricated in Dubai, U.A.E. and then towed the 1,100-mile journey aboard a heavy lift vessel. The Front Runner spar will reside in Green Canyon 338 in a 3,300-foot water depth.

BELOW:
Spinnaker's anticipated production rates will rapidly accelerate as successful deepwater discoveries at Front Runner and Amazon/Spiderman reach maximum production capacity. These two deepwater projects alone should meet or exceed existing production rates.

ANNUALIZED PRODUCTION IMPACT FROM TWO DEEPWATER PROJECTS
(Bcfe)
□Actual
■Front Runner ▨Amazon/Spiderman



Our internal ability to process key geophysical data has been a competitive advantage since Spinnaker was formed, and it continues to differentiate us as we expand our deepwater portfolio. In 2003, we added several plays in the Deep Miocene and various salt-impacted areas of the Gulf. The more capable players in the industry are creating large incremental value with such plays, and our ability to upgrade relatively low cost, non-proprietary seismic data into an essentially proprietary product will benefit us as we further diversify into deep waters. This sequence of technical upgrade has been a precursor to the acquisition of much of Spinnaker's prospect inventory during the past few years. I feel certain that this trend will continue.

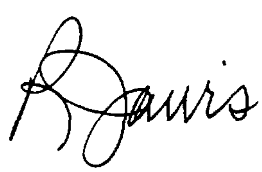
Our allocation of capital to deepwater exploration is likely to rise consistently during the remainder of the decade. The deep water is immature as an exploration province, enjoys expanding infrastructure and has large average field size. Additionally, the play demands a set of skills and assets that we possess at Spinnaker. The province is complex – and our Company is technically detailed and focused. Assuming the continued careful management of our balance sheet, the deep water is a nice fit for Spinnaker.

CHARTING NEW GROWTH

Taken as a whole, 2003 was a year of progress for Spinnaker. With our diversification into deeper waters and the completion of several key development projects, annual production rates are projected to grow significantly beginning in the second half of 2004. Our excellent inventory of exploratory prospects should help us sustain production growth while growing our reserve base. We continue to add to our database and improve our ability to interpret this information – a skill that we believe sets us apart from others who operate in the Gulf of Mexico.

We are proud of the accomplishments of our employee team and their strong commitment to excellence. All of us continue to work diligently to ensure that Spinnaker remains one of the premier players in the Gulf of Mexico – finding economic supplies of oil and gas for our country and delivering growth and value to our shareholders.

As always, we are deeply grateful to you for your support and the confidence that you have placed in us.



ROGER L. JARVIS
CHAIRMAN OF THE BOARD,
PRESIDENT AND CHIEF EXECUTIVE OFFICER

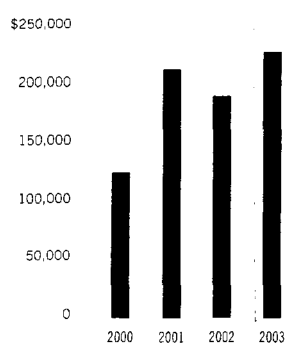
FINANCIAL REVIEW

Spinnaker recognized 2003 net income of $36.6 million, or $1.08 per diluted share, compared to 2002 net income of $31.6 million, or $0.97 per diluted share. Revenues increased $38.5 million, or 20%, primarily due to a 51% higher average commodity price in 2003, partially offset by the impact of an increase in net hedging losses and other of $42.2 million and 5% lower production in 2003.

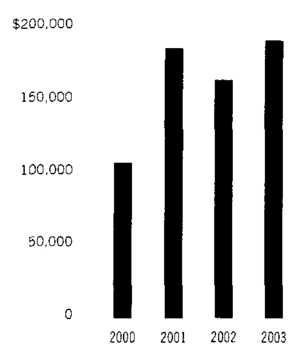
Production decreased approximately 2.4 Bcfe, or 5%, in 2003 compared to 2002 primarily due to normal production declines. Average daily production in 2003 was 134 MMcfe compared to 141 MMcfe in 2002. Natural gas revenues increased $65.0 million, or 42%, due primarily to a 58% higher average price in 2003, partially offset by the impact of a decrease in production of approximately 4.7 Bcf, or 10%. Excluding the effects of hedging activities, the 2003 average natural gas price increased 58% to $5.46 per Mcf compared to $3.46 per Mcf in 2002. Oil and condensate revenues increased $15.8 million, or 57%, due primarily to a 16% higher average realized price in 2003 and an increase in production of approximately 374 MBbls, or 36%. The 2003 average oil and condensate price was $30.56 per barrel compared to $26.39 per barrel in 2002.

Spinnaker ended 2003 with cash and cash equivalents of $15.3 million and debt of $50.0 million. On December 19, 2003, we revised and renewed the three-year $200.0 million revolving credit agreement that provides for an initial borrowing base of $125.0 million and an additional $50.0 million available in multiple advances through April 1, 2005.

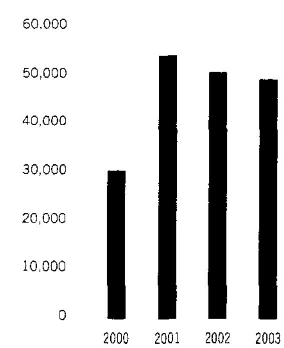
REVENUES
(in thousands)



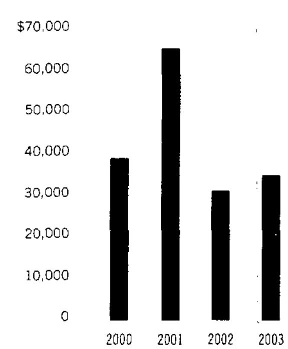
CASH FROM OPERATIONS
(in thousands)



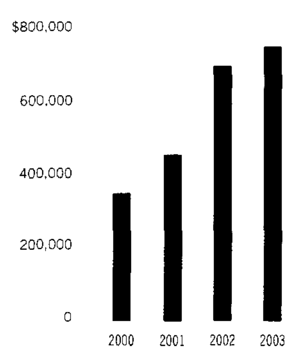
PRODUCTION
(MMcfe)



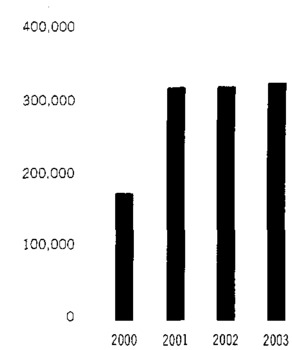
NET INCOME
(in thousands)



EQUITY
(in thousands, as of December 31)



OIL AND GAS RESERVES
(MMcfe, as of December 31)



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 "Exchange Act"). 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;
- oil and gas reserves;
- timing and amount of future production of oil and gas;
- operating costs and other expenses;
- cash flow and anticipated liquidity;
- prospect development and property acquisitions; and
- marketing of oil and gas.

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

- the risks associated with exploration;
- delays in anticipated start-up dates;
- shut-ins of production for platform, pipeline and facility maintenance, additions and removals;
- the ability to find, acquire, market, develop and produce new properties;
- oil and gas price volatility;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;
- downward revisions of proved reserves and the related negative impact on the depreciation, depletion and amortization ("DD&A") rate;
- production and reserves concentrated in a small number of properties;
- operating hazards attendant to the oil and gas business;
- drilling and completion risks, which costs are generally not recoverable from third parties or insurance;
- potential mechanical failure or under-performance of significant wells;
- impact of weather conditions on timing and costs of operations;
- availability and cost of material and equipment;
- 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 Condition and Results of Operations."

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Our objective since inception has been to assemble a large 3-D seismic database and focus on exploration activities exclusively in the Gulf of Mexico because we believe this area represents one of the most attractive exploration regions in North America. We also believe a geographic focus provides an excellent opportunity to develop and maintain competitive advantages through our regional exploration and operating expertise. We try to maintain balance and diversity in our exploration approach by drilling both shallow water and deep-water prospects, ranging from lower-risk prospects to higher-risk, higher-potential prospects.

Spinnaker recognized 2003 net income of $36.6 million, or $1.08 per diluted share, compared to 2002 net income of $31.6 million, or $0.97 per diluted share. These financial results were impacted by a 51% higher average commodity price, 5% lower production and a $42.4 million increase in hedging losses in 2003. The lease operating expense rate per Mcfe increased 31%, primarily due to workover activities. The DD&A expense rate per Mcfe increased 21% in 2003, primarily due to our strategy of maintaining balance and diversity in our exploration activities, particularly in the deep shelf play where higher costs and risks accompany the potential for higher rewards. Spinnaker had $15.3 million in cash and cash equivalents and outstanding borrowings of $50.0 million as of December 31, 2003.

Spinnaker has experienced and expects to continue to experience substantial capital requirements. We have incurred capital costs of almost $1.0 billion in the past three years. Additionally, we have had negative working capital at the end of each of the last three years, including a deficit of $33.2 million as of December 31, 2003. Spinnaker has capital expenditure plans for 2004 totaling approximately $250.0 million. We believe that cash flows from operations, proceeds from available borrowings under the Company's $200.0 million revolving credit agreement dated as of December 19, 2003 (the "Revolver") and the Green Canyon Blocks 338/339/382 ("Front Runner") spar production facility financing opportunities will be sufficient to meet our capital requirements in the next twelve months.

Production of 49.0 Bcfe in 2003 was down 8% from 2001 production of 53.1 Bcfe. Proved oil and gas reserves of 332.6 Bcfe as of December 31, 2003 were up 8% from June 30, 2001 proved reserves of 307.2 Bcfe. Although we have been able to maintain a drilling success rate of approximately 60% since inception, our exploratory drilling successes on the shelf and deep shelf since the second half of 2001 have been smaller and had less impact on our operating results than those prior to that time, resulting in a negative impact on our subsequent production and reserve growth. Additionally, several of our discoveries since mid-2001 were in the deep water, and we do not expect to see the full impact on production from these projects until after 2004.

Production

Since inception, 90% of Spinnaker's total production has been natural gas, including 83% in 2003. Considering oil and condensate production from deepwater projects in 2004 and 2005, we anticipate that this concentration in natural gas production will decrease to approximately three-fourths of total production in 2004 and approximately one-half of total production in 2005. As a result, Spinnaker's revenues, profitability and cash flows will be less sensitive to natural gas prices and more sensitive to oil and condensate prices.

Generally, Spinnaker's producing properties on the shelf have high initial production rates followed by steep declines. As a result, we must continually drill for and develop new oil and gas reserves to replace those being depleted by production. Substantial capital expenditures are required to find and develop these reserves. Our challenge is to find and develop reserves at economic rates and commence production of these reserves as quickly and efficiently as possible.

Oil and Gas Property Costs

Spinnaker participated in 20 successful wells in 29 attempts in 2003. Capital costs incurred for leasehold and other acquisition, exploration and development activities in 2003, excluding asset retirement costs of $30.0 million, totaled $276.2 million compared to $342.5 million in 2002. Excluding asset retirement costs, capital costs incurred for development and leasehold and other acquisition activities totaled approximately 66% of total capital costs incurred in 2003. The majority of the development costs were incurred at Front Runner and Mississippi Canyon 496 ("Zia"). During 2003, we announced the Front Runner spar hull completion and delivery and progress on the related topsides. We expect to take possession of the spar production facility in the summer of 2004, followed by the commencement of well completion activities. Initial production on Front Runner is scheduled for the second half of 2004. Zia, our third successful deepwater completion, commenced production in June 2003. We also announced a deepwater discovery at Desoto Canyon 620/621 (Amazon/Spiderman) in late 2003.

We currently plan to drill approximately 20 wells on the shelf and 13 wells in the deep water in 2004. We expect more than 50% of our 2004 capital expenditure budget to be used for exploration activities, up from 34% in 2003.

Finding and Development Costs

We believe that the DD&A rate is the best measure for evaluating finding and development costs per Mcfe since the rate generally considers all acquisition, exploration and development costs. The rate also considers any additional development costs associated with proved reserves, such as costs for drilling new wells, sidetracks and recompletions, which Spinnaker will incur in the future to produce the oil and gas reserves and an estimate of the costs to abandon wells, platforms, facilities and pipelines after reservoirs are depleted. However, other factors must also be considered when relying on the DD&A rate as a measure for evaluating a company's finding and development costs per Mcfe. In most cases, the total estimated resource of a reservoir is not usually proved with only one well, and the initial proved reserves are generally burdened with 100% of the development costs as well as any future development costs.

The DD&A rate per Mcfe is calculated quarterly and increased 13% to $2.68 in the fourth quarter of 2003 from $2.37 in the fourth quarter of 2002. The increase in the DD&A rate was primarily due to costs of $34.3 million associated with nine unsuccessful wells in 2003 and higher finding costs associated with new discoveries in 2003, as well as the timing and reserve recognition associated with economical discoveries.

Oil and Gas Reserves

Spinnaker has achieved reserve growth through exploration activities. We have not acquired reserves through acquisition activities. As of December 31, 2003, Ryder Scott Company L.P. ("Ryder Scott") estimated net proved reserves at approximately 332.6 Bcfe, with a present value, discounted at 10% per annum, of pre-tax future net cash flows of approximately $1.1 billion. The discovery of the Front Runner field in 2001 significantly changed our reserve profile. Proved oil and condensate reserves were 53% of total proved reserves as of December 31, 2003 compared to 10% as of December 31, 2000. Proved undeveloped reserves were approximately 68% of total proved reserves as of December 31, 2003. Front Runner represented approximately 70% of total proved undeveloped reserves.

Natural Gas and Oil Prices and Hedging Activities

Prices for natural gas and oil fluctuate widely, primarily affecting the amount of cash flow available for capital expenditures, our ability to borrow and raise additional capital and the amount of natural gas and oil that we can economically produce. Natural gas prices have been extremely volatile recently as a result of various factors, including weather, industrial demand and uncertainty related to the ability of the energy industry to provide supply to meet future demand. There are questions whether fundamentals support current natural gas prices.

Spinnaker enters into hedging arrangements from time to time to reduce our exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. However, these contracts also limit the benefits we would realize if prices increase. We recorded a net hedging loss of $42.6 million from 2001 through 2003, including a net hedging loss of $37.7 million in 2003. Major challenges related to our hedging activities include a determination of the proper production volumes to hedge and acceptable commodity price levels for each hedge transaction.

Revenues, profitability, cash flow and future growth depend substantially on prevailing oil and gas prices and our ability to find and develop oil and gas reserves that are economically recoverable. A substantial or extended decline in the prices for oil and gas could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and gas reserves that may be economically produced and access to capital.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of 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 DD&A of proved oil and gas properties. Oil and gas 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. In addition, alternatives may exist among various accounting methods. In such cases, the choice of accounting method may also have a significant impact on reported amounts. Our critical accounting policies are as follows:

Full Cost Method of Accounting

The accounting for oil and gas exploration and production is subject to special accounting rules that are specific to the industry. Two allowable methods exist for these activities: the successful efforts method and the full cost method. Several significant differences exist between the two methods. The major difference is under the successful efforts method, costs such as geological and geophysical, exploratory dry holes and delay rentals are expensed as incurred where under the full cost method, these types of charges are capitalized into the full cost pool.

We use the full cost method of accounting for investments in oil and gas properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of exploring for and developing oil and gas properties are capitalized. 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, completions, platforms, facilities, pipelines and the costs related to the retirement of these assets. Costs associated with production and general corporate activities are expensed in the period incurred. Sales of oil and gas 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 oil and gas reserves.

Application of the full cost method of accounting for oil and gas properties generally results in higher capitalized costs, no exploration costs and higher DD&A rates than the application of the successful efforts method of accounting. Although some of these costs will ultimately result in no additional reserves, we expect the benefits of successful wells to more than offset the costs of any unsuccessful ones. As a result, we believe that the full cost method of accounting better reflects the true economics of exploring for and developing oil and gas reserves. Our financial position and results of operations would have been significantly different had we used the successful efforts method of accounting for our oil and gas investments.

Reserve Estimates

Ryder Scott prepares estimates of our proved oil and gas reserves as of June 30 and December 31 each year. These estimates of proved reserves are based on the quantities of oil and gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. For example, we must estimate, among others, the amount and timing of future production, operating, workover and transportation expenses and development and abandonment costs, all of which may vary considerably from actual results. In addition, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Any significant variance in these assumptions could materially affect the estimated quantity and value of our oil and gas reserves.

Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements. For example, we use the units-of-production method to amortize our oil and gas properties and the quantity of reserves could significantly impact our DD&A rate and related expense. Our oil and gas properties are also subject to a ceiling limitation based in part on the quantity of our proved reserves. Finally, these proved reserves are the basis for our supplemental oil and gas disclosures.

Depreciation, Depletion & Amortization

Spinnaker's full cost DD&A expense is comprised of many factors, including costs incurred in the acquisition, exploration and development of proved oil and gas reserves, production levels, estimates of proved reserve quantities and future development and abandonment costs. Spinnaker computes the provision for DD&A of oil and gas 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 estimated salvage values associated with future asset retirement obligations.

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 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.

As of December 31, 2003, we excluded from the amortization base estimated future expenditures of $29.5 million associated with common development costs for the deepwater discovery at Front Runner. This estimate of future expenditures associated with common development costs is based on existing proved reserves to total proved reserves expected to be established upon completion of the Front Runner project.

If the $29.5 million had been included in the amortization base as of December 31, 2003, and no additional reserves were assigned to the Front Runner project, the DD&A rate as of December 31, 2003 would have been $2.77 per Mcfe, or an increase of $0.09 over the actual DD&A rate of $2.68 per Mcfe. All future development costs associated with the deepwater discovery at Front Runner are included in the determination of estimated future net cash flows from proved oil and gas reserves used in the full cost ceiling calculation, as discussed below.

Full Cost Ceiling

Capitalized costs of oil and gas properties, net of accumulated DD&A, asset retirement obligations and related deferred taxes, are limited to the estimated future net cash flows from proved oil and gas reserves, including the effects of hedging activities in place as of December 31, 2003, discounted at 10%, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (full cost ceiling). If capitalized costs of the full cost pool exceed the ceiling limitation, the excess is charged to expense.

As of December 31, 2003, Spinnaker's full cost ceiling, including estimated future net cash flows calculated using commodity prices of $6.29 per Mcf of natural gas and $30.34 per barrel of oil and condensate, exceeded capitalized costs of oil and gas properties, net of accumulated DD&A, asset retirement obligations and related deferred taxes, by approximately $213.9 million. Considering the volatility of natural gas and oil prices, it is probable that our estimate of discounted future net cash flows from proved oil and gas reserves will change in the near term. If natural gas or oil prices decline, even if for only a short period of time, if we incur significant costs associated with unsuccessful drilling operations or if we have downward revisions to our estimated proved reserves, it is possible that write-downs of oil and gas properties could occur in the future.

Unproved Properties

The costs associated with unproved properties and properties under development are not initially included in the amortization base and primarily relate to unevaluated leasehold acreage and delay rentals, seismic data, wells in-progress and wells pending determination. Unevaluated leasehold costs and delay rentals 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. Unevaluated leasehold costs and delay rentals are transferred to the amortization base if a reduction in value has occurred. The costs of seismic data are transferred to the amortization base using the sum-of-the-year's-digits method over a period of six years. The costs associated with wells in-progress and wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. The costs of drilling exploratory dry holes and associated leasehold costs are included in the amortization base immediately upon determination that the well is unsuccessful.

Leasehold Costs
In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 141, "Business Combinations," which requires the use of the purchase method of accounting for business combinations initiated after June 30, 2001 and eliminates the pooling-of-interests method. In July 2001, the FASB also issued SFAS No. 142, "Goodwill and Other Intangible Assets," which discontinues the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review of impairment. The new standard also requires that, at a minimum, all intangible assets be aggregated and presented as a separate line item in the balance sheet. The adoption of SFAS No. 141 and 142 had no impact on Spinnaker's financial position or results of operations.

A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141 and 142 to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 141 requires registrants to classify the costs of mineral rights associated with extracting oil and gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, we have included the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties. If it is ultimately determined that SFAS No. 141 requires oil and gas companies to classify costs of mineral rights associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, we would be required to reclassify approximately $72.2 million and $59.0 million as of December 31, 2003 and 2002, respectively, from oil and gas properties to a separate intangible assets line item. These costs include those to acquire contract-based drilling and mineral use rights such as delay rentals, lease bonuses, commission and brokerage fees and other leasehold costs. Our cash flows and results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with full cost accounting rules, as allowed by SFAS No. 142. Further, we do not believe the classification of the costs of mineral rights associated with extracting oil and gas as intangible assets would have any impact on compliance with covenants under the Revolver.

Spinnaker will continue to classify its oil and gas leasehold costs as tangible oil and gas properties until further guidance is provided. We anticipate there will be no effect on our results of operations or cash flows.

Asset Retirement Obligations
We recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying amount of the asset. The fair value of a liability for an asset retirement obligation is the amount which that liability could be settled in a current transaction between willing parties. Spinnaker uses the expected cash flow approach for calculating asset retirement obligations. The liability is discounted using the credit-adjusted risk-free interest rate in effect when the liability is initially recognized. The changes in the liability for an asset retirement obligation due to the passage of time are measured by applying an interest method of allocation to the amount of the liability at the beginning of the period. This amount is recognized as an increase in the carrying amount of the liability and as accretion expense classified as an operating item in the statement of operations.

Financial Instruments and Price Risk Management Activities
At December 31, 2003, our 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. Spinnaker enters into hedging arrangements from time to time to reduce our exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. These hedging arrangements take the form of swap contracts or cash less collars and are placed with major trading counterparties. We recorded a net hedging loss of $37.7 million, a net hedging gain of $4.7 million and a net hedging loss of $9.6 million in 2003, 2002 and 2001, respectively.

Stock-Based Compensation
SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure," amends SFAS No. 123 to provide alternative methods of transition for an entity that voluntarily changes to the fair value based method of accounting for stock-based employee compensation and to require prominent disclosure about the effects on reported net income of an entity's accounting policy decisions with respect to stock-based employee compensation. SFAS No. 148 amends Accounting Principles Board ("APB") Opinion No. 28, "Interim Financial Reporting," to require disclosure about those effects in interim financial information.

SFAS No. 123, "Accounting for Stock-Based Compensation," encourages, but does not require, companies to record compensation cost for stock-based employee compensation plans at fair value. We have chosen to account for stock-based compensation using the intrinsic value method prescribed in 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 Spinnaker common stock, par value $0.01 per share ("Common Stock") at the date of the grant over the amount an employee must pay to acquire the Common Stock. In accordance with APB Opinion No. 25, compensation expense related to stock-based compensation was $0, $0.2 million and $0.1 million in 2003, 2002 and 2001, respectively. For further information concerning SFAS 123 see Note 2 of the Notes to Consolidated Financial Statements.

RELATED PARTIES

We purchase oilfield goods, equipment and services from Baker Hughes Incorporated ("Baker Hughes"), Cooper Cameron Corporation ("Cooper Cameron"), National-Oilwell, Inc. ("National-Oilwell") and other oilfield services companies in the ordinary course of business. Spinnaker incurred charges of approximately $7.5 million, $16.1 million and $16.3 million in 2003, 2002 and 2001, respectively, from affiliates of Baker Hughes. Mr. Michael E. Wiley, a director of Spinnaker, serves as Chairman of the Board, Chief Executive Officer and President of Baker Hughes. Spinnaker incurred charges of approximately $0.1 million, $0.1 million and $0.1 million in 2003, 2002 and 2001, respectively, from Cooper Cameron. Mr. Sheldon R. Erikson, a director of Spinnaker, serves as Chairman of the Board, Chief Executive Officer and President of Cooper Cameron. Spinnaker incurred charges of approximately $0.1 million and $0.2 million in 2003 and 2002, respectively, from National-Oilwell. Mr. Roger L. Jarvis, Chairman of the Board, Chief Executive Officer and President of Spinnaker, has served as a director of National-Oilwell since February 2002. These amounts represent less than 1% of Baker Hughes', Cooper Cameron's and National-Oilwell's total revenues.

We believe that these transactions are at arm's-length and the charges we pay 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. Each of these companies is a leader in their respective segments of the oilfield services sector. Spinnaker could be at a disadvantage if it were to discontinue using these companies as vendors.

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 Spinnaker uses cannot eliminate exploration risk and require experienced technical personnel whom we may be unable to attract or retain.

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

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

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

A substantial portion of our proved reserves are associated with the deepwater oil discovery at Front Runner. The development of Front Runner has required and will continue to require financial resources before initial production and remains subject to other uncertainties that could have a material impact on the development of this discovery.

Spinnaker's deepwater oil discovery at Front Runner, in which we have a 25% non-operator working interest, has required and will continue to require significant financial resources in advance of the expected initial production date in the second half of 2004. Spinnaker has incurred $129.4 million in capital expenditures for Front Runner through December 31, 2003 and expects to incur an aggregate of approximately $22.5 million in future development costs during 2004 and $34.6 million after 2004. Because another oil and gas exploration and production company operates Front Runner, we have a limited ability to influence the operations and costs associated with this property.

Front Runner is located in approximately 3,500 feet of water. The eight wells have been drilled in the Front Runner area to total depths in excess of 20,000 feet. We have limited experience with large deepwater and deep drilling depth discoveries similar to Front Runner as most of our prior discoveries have occurred in shallower waters and drilling depths. As a result of these uncertainties and risks, we may encounter difficulties and delays that could cause actual expenditures to exceed anticipated amounts.

Construction of the topsides of the spar production facility is expected to be completed in the second quarter of 2004. Construction of the hull is complete. Weather and other conditions may delay the installation of the spar production facility on location. Any delays in the delivery or installation dates would cause a delay in the initial production date.

Front Runner accounted for approximately 70% of Spinnaker's proved undeveloped reserves as of December 31, 2003. If the actual reserves associated with Front Runner are substantially less than the estimated reserves, our results of operations and financial condition could be adversely affected.

When production ultimately commences for this discovery, it may produce substantially less oil and gas than currently projected. Additionally, we cannot predict commodity prices when production commences. If production is substantially less than currently projected or commodity prices are low, our results of operations and financial condition could be adversely affected.

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, our future business, financial condition and operating results will be materially and adversely affected.

The oil and gas business involves many operating risks that can cause substantial losses.

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

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

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

Exploration for oil and gas 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.
We explore for oil and gas 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 deepwater drilling and operations require the application of recently developed technologies that involve a higher risk of mechanical failure. We have experienced and will continue to experience significantly higher drilling costs for deep depth and deepwater prospects.

As of December 31, 2003, approximately 86% of our proved undeveloped reserves were located in deep water. The deep water lacks the physical and oilfield service infrastructure present in the shallower waters. As a result, deepwater projects require long-term commitments of significant financial resources. Deepwater operations may also require a significant amount of time between the discovery date and the initial production date when we can market the oil or gas, increasing both the financial and operational risk involved with these operations.

Spinnaker is vulnerable to operational, regulatory and other risks associated with the Gulf of Mexico because we currently explore and produce exclusively in that area.
Our operations and revenues are impacted acutely by conditions in the Gulf of Mexico because we currently explore and produce exclusively in that area. This concentration of activity makes us more vulnerable than many of our competitors to the risks associated with the Gulf of Mexico, including delays and increased costs relating to adverse weather conditions, drilling rig and other oilfield services and compliance with environmental and other laws and regulations.

A significant part of the value of our production and reserves is concentrated in a small number of offshore properties. Because of this concentration, any production problems or inaccuracies in reserve estimates related to those properties are more likely to adversely impact our business.
During 2003, approximately 70% of our production came from seven properties in the Gulf of Mexico. If mechanical problems, storms or other events curtailed a substantial portion of this production, our cash flow would be adversely affected. In addition, as of December 31, 2003, our proved reserves were located on 36 different blocks in the Gulf of Mexico, with 73% of the proved reserves attributable to seven of these properties. One property, Front Runner, accounted for approximately 70% of total proved undeveloped reserves and 50% of total proved reserves. If the actual reserves associated with any one of these seven properties are substantially less than the estimated reserves, Spinnaker's results of operations and financial condition could be adversely affected.

Rules and regulations of the Commission allow companies to recognize proved reserves if economic producibility is supported by either actual production or a conclusive formation test. In the absence of a production flow test, compelling technical data must exist to recognize proved reserves. The industry has increasingly depended on advanced technical testing to support economic producibility. Spinnaker has recorded most of its proved reserves in deep water based on various advanced technical tests rather than production flow tests. We expect initial production from the majority of our proved undeveloped reserves in the deep water in the second half of 2004.

If any seismic contractor terminates its data agreement with Spinnaker, our ability to find additional reserves could be impaired.
Our success depends heavily on access to 3-D seismic data. If any seismic contractor terminates its data agreement with us, we would lose access to a portion of the 3-D seismic data, which loss could have an adverse effect on our ability to find additional reserves. A seismic contractor may terminate its data agreement with us on several grounds, including if a competitor of the seismic contractor acquires control of Spinnaker or if we breach the data agreement with that seismic contractor, subject to certain exceptions.

Competitors may use superior technology which we may be unable to afford or which would require costly investments 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, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to it. One or more of the technologies that Spinnaker currently uses or that we may implement in the future

may become obsolete, which may adversely affect our results of operations and financial condition. For example, marine seismic acquisition technology has undergone rapid technological advancements in recent years and further significant technological developments could substantially impair the value of our 3-D seismic data.

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

The process of estimating oil and gas 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.

Ryder Scott prepares Spinnaker's reserve estimates as of June 30 and December 31 each year. In order to assist in the preparation of these estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions such as oil and gas prices, drilling and operating expenses, capital expenditures, taxes and the availability of funds. Even though our reserve estimates are prepared by an independent third party, these estimates of oil and gas reserves are still inherently imprecise.

Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, estimates of proved reserves may be adjusted to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control. Moreover, some of the producing wells included in the reserve report had produced for only a relatively short period of time as of December 31, 2003. Because most of the reserve estimates are not based on a lengthy production history and are calculated using volumetric analysis, these estimates are less reliable than estimates based on a lengthy production history.

It should not be assumed that the present value of future net cash flows from our proved reserves is the current market value of our estimated oil and gas reserves. In accordance with Commission requirements, we base the estimated discounted future net cash flows from 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 present value of future net cash flows estimate.

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

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

Relatively short rates of production for Gulf of Mexico properties compared to other producing regions of the world subject us to more active reserve replacement efforts, require us to incur capital expenditures more frequently to replace production and generate growth in reserves and may impair our ability to slow or shut-in production during periods of low prices for oil and gas.

Reservoirs in the Gulf of Mexico are generally sandstone reservoirs characterized by high porosity, permeability, pressure and temperature. Production of these reservoirs is generally constant for a relatively shorter period of time with a rapid decline in production at the end of the reservoir life compared to production of reservoirs in many other producing regions of the world. As a result, our reserve replacement needs from new prospects in the Gulf of Mexico are greater and require us to incur capital expenditures more frequently to replace production than would typically be required in many other producing regions of the world. We expect a decline in production in the first quarter of 2004 due to the rapid production decline of certain producing wells, timing related to first production from recent shelf discoveries and shut-ins for facility work not related to our properties.

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

Natural gas and oil prices fluctuate widely, and low prices could have a material adverse impact on our business and financial results.
Our revenues, profitability and future growth depend substantially on prevailing oil and gas prices. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under the Revolver is subject to periodic re-determination based in part on changing expectations of future prices. Lower prices may also reduce the amount of oil and gas that we can economically produce.

Prices for natural gas and oil fluctuate widely. 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 oil and gas producing regions, the domestic and foreign supply of oil and gas, 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 oil and gas 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.
Spinnaker enters into hedging arrangements from time to time to reduce our exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. These financial arrangements take the form of swap contracts or cashless collars and are placed with major trading counterparties we believe represent minimum credit risks. We cannot provide assurance that these trading counterparties will not become credit risks in the future. Hedging arrangements expose us to risks in some circumstances, including situations when the other party to the hedging contract defaults on its contract obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. These hedging arrangements have limited and may continue to limit the benefit we could receive from increases in the prices for natural gas and oil. We cannot provide assurance that the hedging transactions we have entered into, or will enter into, will adequately protect us from fluctuations in natural gas and oil prices. We may choose not to engage in hedging transactions in the future. As a result, Spinnaker may be adversely affected during periods of declining natural gas and oil prices.

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

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

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

Competition in the industry is intense, and Spinnaker is smaller and has a more limited operating history than most of our competitors in the Gulf of Mexico.

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

We cannot control the activities on properties we do not operate.

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

We may have difficulty financing our planned growth.

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

Warburg owns a significant number of shares 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, 2003, Warburg owned approximately 20% 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. Warburg's influence over Spinnaker may delay or prevent a change of control of Spinnaker and may adversely affect the voting and other rights of other stockholders.

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

A portion of our 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 our 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 Spinnaker.

The certificate of incorporation authorizes the Board of Directors to issue Preferred Stock without stockholder approval. If the Board of Directors elects to issue outstanding Series A Convertible Preferred Stock, par value $0.01 per share ("Preferred Stock"), it could be more difficult for a third party to acquire control of Spinnaker, 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 Spinnaker.

Terrorist attacks on oil and gas production facilities, transportation systems and storage facilities could have a material adverse impact on our business.

Oil and gas production facilities, transportation systems and storage facilities could be targets of terrorist attacks. These attacks could have a material adverse impact on our results of operations and cash flows if certain oil and gas infrastructure integral to our operations were destroyed or damaged.

RESULTS OF OPERATIONS

Year Ended December 31,	2003	2002	2001	% Change from 2002 to 2003	% Change from 2001 to 2002
Production:					
Natural gas (MMcf)	40,527	45,180	51,234	(10%)	(12%)
Oil and condensate (MBbls)	1,414	1,040	310	36%	235%
Total (MMcfe)	49,010	51,419	53,094	(5%)	(3%)
Revenues (in thousands):					
Natural gas	$ 221,179	$ 156,214	$ 212,238	42%	(26%)
Oil and condensate	43,208	27,448	7,718	57%	256%
Net hedging income (loss)	(37,717)	4,664	(9,580)	(909%)	149%
Other	180	–	–	–	–
Total	$ 226,850	$ 188,326	$ 210,376	20%	(10%)
Average realized sales price per unit:					
Natural gas revenues from production (per Mcf)	$ 5.46	$ 3.46	$ 4.14	58%	(16%)
Effects of hedging activities (per Mcf)	(0.93)	0.10	(0.18)	(1,030%)	156%
Average realized price (per Mcf)	$ 4.53	$ 3.56	$ 3.96	27%	(10%)
Oil and condensate revenues from production (per Bbl)	$ 30.56	$ 26.39	$ 24.90	16%	6%
Effects of hedging activities (per Bbl)	–	–	–	–	–
Average realized price (per Bbl)	$ 30.56	$ 26.39	$ 24.90	16%	6%
Total revenues from production (per Mcfe)	$ 5.39	$ 3.57	$ 4.14	51%	(14%)
Effects of hedging activities (per Mcfe)	(0.77)	0.09	(0.18)	(956%)	150%
Total average realized price (per Mcfe)	$ 4.62	$ 3.66	$ 3.96	26%	(8%)
Expenses (per Mcfe):					
Lease operating expenses	$ 0.46	$ 0.35	$ 0.23	31%	52%
Depreciation, depletion and amortization – oil and gas properties	$ 2.56	$ 2.12	$ 1.60	21%	33%

Year Ended December 31, 2003 as Compared to the Year Ended December 31, 2002

Revenues and Production

Revenues increased $38.5 million, or 20%, in 2003 compared to 2002. The increase was primarily due to a 51% higher average commodity price in 2003, partially offset by the impact of an increase in net hedging losses and other of $42.2 million and 5% lower production in 2003.

Production decreased approximately 2.4 Bcfe, or 5%, in 2003 compared to 2002 primarily due to normal production declines. Average daily production in 2003 was 134 MMcfe compared to 141 MMcfe in 2002. Natural gas revenues increased $65.0 million, or 42%, due primarily to a 58% higher average price in 2003, partially offset by the impact of a decrease in production of approximately 4.7 Bcf, or 10%. Excluding the effects of hedging activities, the 2003 average natural gas price increased 58% to $5.46 per Mcf compared to $3.46 per Mcf in 2002. Oil and condensate revenues increased $15.8 million, or 57%, due primarily to a 16% higher average realized price in 2003 and an increase in production of approximately 374 MBbls, or 36%. The 2003 average oil and condensate price was $30.56 per barrel compared to $26.39 per barrel in 2002. We expect a decline in production in the first quarter of 2004 due to the rapid production decline of certain producing wells, timing related to first production from recent shelf discoveries and shut-ins for facility work not related to our properties.

Lease Operating Expenses

Lease operating expenses include costs incurred to operate and maintain wells and related equipment and facilities. These costs include, among others, workover expenses, labor, materials, supplies, property taxes, insurance, severance taxes and transportation, gathering and processing expenses. Lease operating expenses increased $4.3 million, or 23%, in 2003 compared to 2002. Of the total increase in lease operating expenses, approximately $1.4 million related to increased workover activities, $2.0 million related to activity on blocks that commenced production subsequent to December 31, 2002 and $0.9 million related to increased operating expenses on existing properties. The 31% increase in the lease operating expense rate per Mcfe in 2003 was primarily due to a pipeline workover on Green Canyon 177 (Sangria) of $2.4 million, or $0.05 per Mcfe, and lower production volumes.

Depreciation, Depletion and Amortization

DD&A increased $16.3 million, or 15%, in 2003 compared to 2002. Of the total increase in DD&A, $22.5 million related to a higher DD&A rate, offset in part by $6.2 million related to lower production volumes of 2.4 Bcfe. The 21% increase in the DD&A rate was primarily due to costs of $34.3 million associated with nine unsuccessful wells in 2003 and higher finding costs associated with new discoveries in 2003, as well as the timing and reserve recognition associated with economical discoveries.

General and Administrative

General and administrative expenses are overhead-related expenses, including among others, wages and benefits for non-capitalized employees, auditing fees, legal fees, insurance, office rent, travel and entertainment, computer supplies and maintenance and investor relations expenses. General and administrative expenses increased $1.8 million, or 16%, in 2003 compared to 2002. The increase was primarily due to higher employment-related costs associated with an increase in the number of employees in 2002 and 2003.

Year Ended December 31, 2002 as Compared to the Year Ended December 31, 2001

Revenues and Production

Revenues decreased $22.1 million, or 10%, in 2002 compared to 2001. The decrease was primarily due 3% lower production and a 14% lower realized commodity price in 2002, partially offset by the impact of an increase in net hedging income of $14.2 million in 2002.

Production decreased approximately 1.7 Bcfe, or 3%, in 2002 compared to 2001. Average daily production in 2002 was 141 MMcfe compared to 145 MMcfe in 2001. Natural gas revenues decreased $56.0 million, or 26%, due primarily to 12% lower production and a 16% lower average price in 2002. The production declines of certain producing wells, particularly in the High Island 202 area, resulted in lower natural gas production in 2002. Excluding the effects of hedging activities, the 2002 average natural gas price decreased 16% to $3.46 per Mcf compared to $4.14 per Mcf in 2001. Oil and condensate revenues increased $19.7 million, or 256%, due to an increase in production of approximately 730 MBbls, or 235%, and a 6% higher average realized price in 2002. The 2002 average oil and condensate price was $26.39 per barrel compared to $24.90 per barrel in 2001. We expected a decline in production during the first quarter of 2003 due to the rapid production decline of certain producing wells and shut-ins for pipeline repairs.

Lease Operating Expenses

Lease operating expenses increased $6.1 million, or 50%, in 2002 compared to 2001. Of the total increase in lease operating expenses, approximately $7.3 million was attributable to wells on ten new blocks that commenced production in 2002, offset in part by decreases of $0.9 million in operating expenses associated with existing wells and $0.3 million in workovers in 2002. The 52% increase in the lease operating expense rate per Mcfe in 2002 compared to 2001 was primarily due to the production declines of certain wells in the High Island 202 area where the lease operating rate in 2001 was significantly lower compared to other producing areas operated by Spinnaker. Additionally, we experienced higher lease operating rates associated with new wells compared to our historical average lease operating rates due to well locations, transportation and gathering agreements and processing requirements.

Depreciation, Depletion and Amortization

DD&A increased $23.9 million, or 28%, in 2002 compared to 2001. Of the total increase in DD&A, $26.6 million related to an increase in the DD&A rate, offset in part by $2.7 million related to lower production volumes of 1.7 Bcfe in 2002. The 33% increase in the DD&A rate per Mcfe was primarily due to costs of $72.6 million associated with 12 unsuccessful wells and higher finding costs associated with new discoveries in 2002.

General and Administrative

General and administrative expenses increased $1.5 million, or 16%, in 2002 compared to 2001. The increase was primarily due to higher employment-related costs associated with an increase in the number of employees in 2001 and 2002 and an increase in professional services fees.

Interest Income

Interest income decreased $2.6 million, or 72%, in 2002 compared to 2001 primarily due to lower average cash and short-term investment balances and significantly lower interest rates in 2002.

LIQUIDITY AND CAPITAL RESOURCES

Revenues, profitability, cash flow and future growth depend substantially on prevailing oil and gas prices and our ability to find and develop oil and gas reserves that are economically recoverable. A substantial or extended decline in the prices for natural gas or oil could have a material adverse effect on Spinnaker's financial position, results of operations, cash flows, quantities of oil and gas reserves that may be economically produced and access to capital.

We have experienced and expect to continue to experience substantial capital requirements, primarily due to our active exploration and development programs in the Gulf of Mexico. Spinnaker has capital expenditure plans for 2004 totaling approximately $250.0 million. We use a risk-weighted model to calculate budgeted capital expenditures on a project-by-project basis. If we experience greater than anticipated success on budgeted projects, capital expenditures will increase.

Net additions to property and equipment in 2003 were $308.3 million, including asset retirement costs of $30.0 million. We incurred capital expenditures of approximately $81.3 million in 2003 related to deepwater development activities, including $48.3 million associated with the deepwater discovery at Front Runner. Inception-to-date capital expenditures through December 31, 2003 on the Front Runner project were $129.4 million. As of December 31, 2003, we expect to incur approximately $57.1 million in future development costs related to Front Runner, including approximately $22.5 million in 2004 and $34.6 million thereafter.

Natural gas and oil prices have a significant impact on our cash flows available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under the Revolver is subject to semi-annual re-determination based in part on changing expectations of future prices. Lower prices may also reduce the amount of natural gas and oil that we can economically produce. Lower prices and/or lower production may decrease revenues, cash flows and the borrowing base under the Revolver, thus reducing the amount of financial resources available to meet our capital requirements. We believe that cash flows from operations, proceeds from available borrowings under the Revolver and Front Runner spar production facility financing opportunities will be sufficient to meet our capital requirements in the next twelve months. However, additional debt or equity financing may be required in the future to fund growth and exploration and development activities. In the event additional capital resources are unavailable, we may curtail drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis. As of December 31, 2003, we had borrowings of $50.0 million and were in compliance with the covenants and restrictive provisions under the Revolver. Subsequent to December 31, 2003, we borrowed an additional $25.0 million and expect to incur additional borrowings under the Revolver in 2004.

Spinnaker has an effective shelf registration statement relating to the potential public offer and sale by us or certain of our affiliates of up to $500.0 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 we will or could sell any such securities.

Contractual Obligations

We lease administrative offices, office equipment and oil and gas equipment under non-cancelable operating leases. Contractual obligations as of December 31, 2003 were as follows (in thousands):

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	$ 50,000	$ –	$ 50,000	$ –	$ –
Operating leases	4,628	1,470	3,154	4	–
Other contractual obligations [1]	6,275	6,275	–	–	–
Total	$ 60,903	$ 7,745	$ 53,154	$ 4	$ –

[1] Contractual obligations for seismic data acquisitions.

We will incur obligations in the ordinary course of business under purchase and service agreements that are not included in the table above. These obligations, among others, include estimated future development costs of approximately $177.5 million for the costs of drilling additional wells, completions, recompletions, platforms, pipelines, facilities, tie-backs and abandonments related to our proved reserves. Our asset retirement obligations as of December 31, 2003 were $33.0 million.

Components of Cash Flow

Cash and cash equivalents decreased $17.2 million to $15.3 million as of December 31, 2003. The components of the decrease in cash and cash equivalents included $198.1 million provided by operating activities, $266.0 million used in investing activities and $50.7 million provided by financing activities.

Operating Activities

Net cash provided by operating activities in 2003 increased 29% to $198.1 million primarily due to higher commodity prices. Cash flow from operations is dependent upon our ability to increase production through exploration and development activities and the prices of natural gas and oil. We have made significant investments to expand our operations in the Gulf of Mexico.

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

As of December 31, 2003, Spinnaker had negative working capital of $33.2 million. Our cash flow from operations depends on our ability to manage working capital, including accounts receivable, accounts payable and accrued liabilities. The net decrease of $7.5 million in accounts receivable was primarily related to decreases of $3.9 million in joint interest billings and $3.6 million in oil and gas revenues receivable. Joint interest billings fluctuate from period to period based on the number of wells operated by Spinnaker and the timing of billings to and collections from other working interest owners. Oil and gas revenues receivable decreased primarily due to lower production in December 2003 compared to December 2002, offset in part by higher commodity prices in December 2003. Other current assets decreased $7.2 million primarily due to a lower deferred tax asset related to hedging liabilities at the end of 2003 compared to 2002. Accounts payable and accrued liabilities increased $11.6 million. Fluctuations from period to period occur based on exploratory and development activities in progress and the timing of payments made by Spinnaker to vendors and other operators.

Investing Activities

Net cash used in investing activities was $266.0 million in 2003 and included oil and gas property cash expenditures of $264.3 million and purchases of other property and equipment of $2.8 million. Spinnaker received proceeds of $1.1 million from the sale of oil and gas property and equipment in the first quarter of 2003.

As part of our strategy, we explore for oil and gas at deeper drilling depths and in the deep waters of the Gulf of Mexico, where operations are more difficult and costly than at shallower drilling depths and in shallower waters. Along with higher risks and costs associated with these areas, greater opportunity exists for reserve additions. We have experienced and will continue to experience significantly higher drilling costs for deep shelf and deepwater projects relative to the drilling costs on shallower depth shelf projects in the Gulf of Mexico. We drilled 29 wells in 2003, 20 of which were successful. We drilled 26 wells in 2002, 14 of which were successful. Since inception and through December 31, 2003, we drilled 149 wells, 90 of which were successful, representing a success rate of 60%. Dry hole costs, including associated leasehold costs, were $34.3 million in 2003.

We have capital expenditure plans for 2004 totaling approximately $250.0 million, primarily for costs related to acquisition, exploration and development activities. We settled asset retirement obligations of $3.9 million in 2003 and do not currently anticipate any significant abandonment or dismantlement expenditures in 2004. Actual levels of capital expenditures may vary due to many factors, including drilling results, oil and gas 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. The costs associated with unproved properties and properties under development not included in the amortization base were as follows (in thousands):

As of December 31,	2003	2002
Leasehold, delay rentals and seismic data	$ 119,708	$ 122,409
Wells in-progress	29,459	17,639
Other	2,047	1,278
Total	$ 151,214	$ 141,326

Financing Activities

Net cash provided by financing activities of $50.7 million in 2003 related to proceeds of $50.0 million from borrowings and $2.1 million from stock option exercises. We paid debt issue costs of $1.4 million in connection with the renewal of the Revolver.

On December 28, 2001, Spinnaker entered into an unsecured $200.0 million credit facility ("Credit Facility") with a group of seven banks. The borrowing base of the three-year Credit Facility was re-determined on a semi-annual basis. The banks and we also had the option to request one additional re-determination each year. The banks could also require a borrowing base re-determination if they permitted the sale, transfer or disposition of assets included in the borrowing base valued in excess of $20.0 million. The banks determined the borrowing base in their sole discretion and in their usual and customary manner. The amount of the borrowing base was a function of the banks' view of our reserve profile future commodity prices and projected cash flows. The borrowing base was $100.0 million as of December 18, 2003. We had the option to elect to use a base interest rate as described below or the London Interbank Offered Rate ("LIBOR") plus, for each such rate, a spread based on the percentage of the borrowing base used at that time. The base interest rate under the Credit Facility was a fluctuating rate of interest equal to the higher of either (i) The Toronto-Dominion Bank's base rate for dollar advances made in the United States or (ii) the Federal Funds Rate plus 0.5% per annum. The commitment fee rate ranged from 0.3% to 0.5%, depending on borrowing base usage. The Credit Facility contained various covenants and restrictive provisions.

On December 19, 2003, Spinnaker revised and renewed the $200.0 million revolving credit agreement (the "Revolver") with a group of eight banks. The Revolver consists of two tranches, Tranche A and Tranche B, and matures on December 19, 2006. Borrowings under each tranche constitute senior indebtedness.

Tranche A is available on a revolving basis through the maturity of the Revolver, and availability is subject to the borrowing base, currently $125.0 million, as determined by the banks. Tranche B is $50.0 million, is available in multiple advances through April 1, 2005 and is not subject to the borrowing base. Borrowings under Tranche B cannot be reborrowed once repaid. Total availability under Tranche A and Tranche B cannot exceed $200.0 million. Should the borrowing base exceed $150.0 million, Tranche B would be reduced by a like amount for the period the borrowing base exceeds $150.0 million until the maturity of Tranche B. At such time Tranche B is utilized, the banks are to be provided with security interests in virtually all of Spinnaker's reserve base. Upon repayment of Tranche B, the security interests are to be released.

The borrowing base is re-determined semi-annually by the banks in their sole discretion and in their usual and customary manner. The banks and Spinnaker also have the right to request one additional re-determination annually. The amount of the borrowing base is a function of the banks' view of our reserve profile, future commodity prices and projected cash flows. In addition to the semi-annual re-determinations, the banks have the right to re-determine the borrowing base in the event of the sale, transfer or disposition of assets included in the borrowing base exceeding $25.0 million, or $10.0 million when Tranche B is utilized.

We have the option to elect to use a base interest rate as described below or LIBOR plus, for each such rate, a spread based on the percentage of the borrowing base used at that time. The base rate spread ranges from 0.0% to 0.5% for Tranche A borrowings and from 2.0% to 2.75% for Tranche B borrowings. The LIBOR spread ranges from 1.25% to 2.0% for Tranche A borrowings and from 3.0% to 3.75% for Tranche B borrowings. The base interest rate under the Revolver is a fluctuating rate of interest equal to the higher of either (i) The Toronto-Dominion Bank's base rate for dollar advances made in the United States or (ii) the Federal Funds Rate plus 0.5% per annum. The commitment fee rate ranges from 0.375% to 0.5%, depending on the borrowing base usage for Tranche A and is 0.625% for Tranche B.

The Revolver also includes the following restrictions and covenants:

- Other debt is prohibited except that senior debt may not exceed $10.0 million ($5.0 million when Tranche B is used), vendor indebtedness for the purchase of seismic data may not exceed $25.0 million, subordinated debt is permitted subject to certain conditions and a lease transaction involving the Front Runner spar is specifically permitted.
- Liens are generally prohibited; however, we may grant a lien in the purchase of seismic data and pledges and deposits to secure hedging arrangements not to exceed $15.0 million.
- Dividends and stock buy-backs exceeding $10.0 million are prohibited in any fiscal year.
- The ratio of debt to EBITDA may not exceed 2.50 to 1.00.
- The ratio of current assets to current liabilities may not be less than 1.00 to 1.00. For purposes of the calculation, availability under the Revolver is added to current assets and maturities of the Revolver are excluded from current liabilities. Hedging assets and liabilities are also excluded from this calculation.
- Our tangible net worth is required to exceed 80% of the level at September 30, 2003, plus 50% of net income with certain non-cash gains and losses excluded from net income, plus 75% of future equity issuances.
- Our hedging transactions must not exceed 66⅔% of estimated future production for the next 18 months and 33⅓% for the period 19 to 36 months from the date of the transaction. There are also credit rating restrictions on counterparties as well as concentration limits.

On December 31, 2003, we had outstanding borrowings of $50.0 million and were in compliance with the covenants and restrictive provisions under the Revolver. Subsequent to December 31, 2003, we borrowed an additional $25.0 million and expect to incur additional borrowings under the Revolver in 2004.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Spinnaker's revenues, profitability and future growth depend substantially on prevailing oil and gas prices. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. Lower prices may also reduce the amount of natural gas and oil that we can economically produce. We sell our natural gas and oil production under fixed or floating market price contracts. Spinnaker enters into hedging arrangements from time to time to reduce our exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. Spinnaker does not enter into such hedging arrangements for trading purposes. However, these contracts also limit the benefits we would realize if prices increase. Our current financial derivative contracts include fixed price swap contracts and cashless collar arrangements that have been placed with major trading counterparties we believe represent minimum credit risks. We cannot provide assurance that these trading counterparties will not become credit risks in the future. Under our current hedging practice, we generally do not hedge more than 66 2/3% of our estimated twelve-month production quantities without the prior approval of the Risk Management Committee of the Board of Directors.

We enter into NYMEX related swap contracts and collar arrangements from time to time. These swap contracts and collar arrangements 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 us for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. We are 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. As of December 31, 2003, our commodity price risk management positions in fixed price natural gas swap contracts and related fair values were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Price (Per MMBtu)	Fair Value (in thousands)
First Quarter 2004	35,000	$ 6.04	$ (235)
Second Quarter 2004	15,000	4.91	(350)
Third Quarter 2004	15,000	4.87	(370)
Fourth Quarter 2004	8,370	4.92	(245)
Year 2004	18,306	5.44	$ (1,200)

In a collar arrangement, the counterparty is required to make a payment to us for the difference between the fixed floor price and the settlement price if the settlement price is below the fixed floor price. We are required to make a payment to the counterparty for the difference between the fixed ceiling price and the settlement price if the settlement price is above the fixed ceiling price. Neither party is required to make a payment if the settlement price falls between the fixed floor and ceiling prices. As of December 31, 2003, our commodity price risk management positions in natural gas collar arrangements and related fair values were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Ceiling Price (Per MMBtu)	Weighted Average Floor Price (Per MMBtu)	Fair Value (in thousands)
First Quarter 2004	20,000	$ 6.64	$ 5.25	$ (407)
Second Quarter 2004	20,000	5.48	4.38	(375)
Third Quarter 2004	20,000	5.48	4.38	(383)
Fourth Quarter 2004	13,370	5.56	4.44	(335)
Year 2004	18,384	5.81	4.63	$ (1,500)

We reported net liabilities of $2.7 million and $19.9 million related to financial derivative contracts as of December 31, 2003 and 2002, respectively. Amounts related to hedging activities were as follows (in thousands):

As of December 31,	2003	2002
Current assets:		
Hedging assets	$ 203	$ –
Deferred tax asset related to hedging activities	972	7,170
Current liabilities:		
Hedging liabilities	$ 2,903	$ 19,917
Equity:		
Accumulated other comprehensive loss	$ (1,728)	$ (12,747)

We recognized no ineffective component of the derivatives and net hedging gains (losses) in revenues in 2003, 2002 and 2001 as follows (in thousands):

Year Ended December 31,	2003	2002	2001
Net hedging income (loss)	$ (37,717)	$ 4,664	$ (9,580)

Based on future natural gas prices as of December 31, 2003, we would reclassify a net loss of $2.7 million from accumulated other comprehensive loss to earnings in 2004. The amounts ultimately reclassified into earnings will vary due to changes in the fair value of the open derivative contracts prior to settlement.

To calculate the potential effect of the derivative contracts on future revenues, we applied NYMEX natural gas forward prices as of December 31, 2003 to the quantity of our natural gas production covered by those derivative contracts as of that date. The following table shows the estimated potential effects of the derivative financial instruments on future revenues (in thousands):

Derivative Instrument	Estimated Decrease in Revenues at Current Prices	Estimated Increase in Revenues with 10% Decrease in Prices	Estimated Decrease in Revenues with 10% Increase in Prices
Fixed price swap transactions	$ (1,200)	$ 1,263	$ (3,676)
Collar arrangements	$ (1,500)	$ 134	$ (5,336)

Subsequent to December 31, 2003, the fair value of our commodity price risk management positions in fixed price natural gas swap contracts and natural gas collar arrangements using an average natural gas forward price of $5.59 as of March 10, 2004 was a net liability of approximately $1.4 million, including first quarter 2004 settlements resulting in income of $1.7 million. Following are Spinnaker's commodity price risk management positions in fixed price natural gas swap contracts and natural gas collar arrangements as of March 10, 2004:

Natural Gas Swap Contracts

Period	Average Daily Volume (MMBtus)	Weighted Average Price (Per MMBtu)
First Quarter 2004	40,556	$ 6.06
Second Quarter 2004	30,000	5.17
Third Quarter 2004	30,000	5.13
Fourth Quarter 2004	8,370	4.92
Year 2004	27,151	5.47

Natural Gas Collar Arrangements

Period	Average Daily Volume (MMBtus)	Weighted Average Ceiling Price (Per MMBtu)	Weighted Average Floor Price (Per MMBtu)
First Quarter 2004	20,000	$ 6.64	$ 5.25
Second Quarter 2004	20,000	5.48	4.38
Third Quarter 2004	20,000	5.48	4.38
Fourth Quarter 2004	13,370	5.56	4.44
Year 2004	18,384	5.81	4.63

Interest Rate Risk

Spinnaker is exposed to changes in interest rates. Changes in interest rates affect the interest earned on cash and cash equivalents and the interest rate paid on borrowings under the Revolver. We do not currently use interest rate derivative financial instruments to manage exposure to interest rate changes, but may do so in the future.

INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying consolidated balance sheets of Spinnaker Exploration Company and subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of operations, equity and cash flows for each of the years in the three-year period ended December 31, 2003. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Spinnaker Exploration Company and subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As explained in Note 2 to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations, and effective January 1, 2001, the Company changed its method of accounting for derivative instruments.

KPMG LLP

Houston, Texas
February 17, 2004

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share data)

As of December 31,	2003	2002
Assets		
CURRENT ASSETS:		
Cash and cash equivalents	$ 15,315	$ 32,543
Accounts receivable, net of allowance for doubtful accounts of $3,232 as of December 31, 2003 and 2002, respectively	30,067	37,572
Hedging assets	203	–
Other	4,193	11,438
Total current assets	49,778	81,553
PROPERTY AND EQUIPMENT:		
Oil and gas, on the basis of full-cost accounting:		
Proved properties	1,175,443	879,840
Unproved properties and properties under development, not being amortized	151,214	141,326
Other	17,309	14,461
	1,343,966	1,035,627
Less – Accumulated depreciation, depletion and amortization	(404,298)	(274,773)
Total property and equipment	939,668	760,854
OTHER ASSETS	1,136	308
Total assets	$ 990,582	$ 842,715
Liabilities and Equity		
CURRENT LIABILITIES:		
Accounts payable	$ 18,723	$ 29,453
Accrued liabilities and other	60,874	38,542
Hedging liabilities	2,903	19,917
Asset retirement obligations, current portion	446	–
Total current liabilities	82,946	87,912
LONG-TERM DEBT	50,000	–
ASSET RETIREMENT OBLIGATIONS	32,548	–
DEFERRED INCOME TAXES	81,027	61,826
COMMITMENTS AND CONTINGENCIES (Note 11)		
EQUITY:		
Preferred stock, $0.01 par value; 10,000,000 shares authorized; no shares issued and outstanding as of December 31, 2003 and 2002, respectively	–	–
Common stock, $0.01 par value; 50,000,000 shares authorized; 33,385,248 shares issued and 33,374,844 shares outstanding as of December 31, 2003 and 33,184,463 shares issued and 33,171,759 shares outstanding as of December 31, 2002	334	332
Additional paid-in capital	599,532	596,087
Retained earnings	145,949	109,337
Less: Treasury stock, at cost, 10,404 and 12,704 shares as of December 31, 2003 and 2002, respectively	(26)	(32)
Accumulated other comprehensive loss	(1,728)	(12,747)
Total equity	744,061	692,977
Total liabilities and equity	$ 990,582	$ 842,715

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

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except share data)

Year Ended December 31,	2003	2002	2001
REVENUES	$ 226,850	$ 188,326	$ 210,376
EXPENSES:			
Lease operating expenses	22,489	18,212	12,132
Depreciation, depletion and amortization – oil and gas properties	125,331	108,998	85,059
Depreciation and amortization - other	1,310	914	398
Accretion expense	2,251	–	–
Gain on settlement of asset retirement obligations	(464)	–	–
General and administrative	12,773	10,984	9,443
Charges related to Enron bankruptcy	–	128	3,059
Total expenses	163,690	139,236	110,091
INCOME FROM OPERATIONS	63,160	49,090	100,285
OTHER INCOME (EXPENSE):			
Interest income	201	1,014	3,574
Interest expense, net	(784)	(762)	(381)
Other	140	–	–
Total other income (expense)	(443)	252	3,193
INCOME BEFORE INCOME TAXES	62,717	49,342	103,478
Income tax expense	22,578	17,763	37,252
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	40,139	31,579	66,226
Cumulative effect of change in accounting principle (Note 2)	(3,527)	–	–
NET INCOME	$ 36,612	$ 31,579	$ 66,226
BASIC INCOME PER COMMON SHARE:			
Income before cumulative effect of change in accounting principle	$ 1.21	$ 1.00	$ 2.45
Cumulative effect of change in accounting principle	(0.11)	–	–
NET INCOME PER COMMON SHARE	$ 1.10	$ 1.00	$ 2.45
DILUTED INCOME PER COMMON SHARE:			
Income before cumulative effect of change in accounting principle	$ 1.18	$ 0.97	$ 2.34
Cumulative effect of change in accounting principle	(0.10)	–	–
NET INCOME PER COMMON SHARE	$ 1.08	$ 0.97	$ 2.34
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:			
Basic	33,234	31,695	27,079
Diluted	33,880	32,653	28,360

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

Spinnaker Exploration Company

CONSOLIDATED STATEMENTS OF EQUITY

(In thousands, except share data)

	Shares Issued		Par Value		Additional Paid-In Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Total Equity	Comprehensive Income
	Preferred	Common	Preferred	Common						
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	
Net income	–	–	–	–	–	31,579	–	–	31,579	$ 31,579
Other comprehensive income, net of tax:										
Net change in fair value of derivative financial instruments	–	–	–	–	–	–	–	(24,269)	(24,269)	(24,269)
Financial derivative settlements reclassed to income	–	–	–	–	–	–	–	(2,985)	(2,985)	(2,985)
Comprehensive income										$ 4,325
Common stock issuance, net of issuance costs	–	5,750,000	–	58	227,326	–	–	–	227,384	
Exercise of stock options	–	116,489	–	1	948	–	7	–	956	
Employer contributions to 401(k) Plan	–	9,062	–	–	287	–	–	–	287	
Stock compensation costs	–	–	–	–	177	–	–	–	177	
Tax benefit associated with exercise of non-qualified stock options	–	–	–	–	1,356	–	–	–	1,356	
Balance, December 31, 2002	–	33,184,463	$ –	$ 332	$ 596,087	$ 109,337	$ (32)	$ (12,747)	$ 692,977	
Net income	–	–	–	–	–	36,612	–	–	36,612	$ 36,612
Other comprehensive income, net of tax:										
Net change in fair value of derivative financial instruments	–	–	–	–	–	–	–	(13,120)	(13,120)	(13,120)
Financial derivative settlements reclassed to income	–	–	–	–	–	–	–	24,139	24,139	24,139
Comprehensive income										$ 47,631
Exercise of stock options	–	184,661	–	2	2,129	–	6	–	2,137	
Employer contributions to 401(k) Plan	–	16,124	–	–	363	–	–	–	363	
Tax benefit associated with exercise of non-qualified stock options	–	–	–	–	953	–	–	–	953	
Balance, December 31, 2003	–	33,385,248	$ –	$ 334	$ 599,532	$ 145,949	$ (26)	$ (1,728)	$ 744,061	

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

Year Ended December 31,	2003	2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 36,612	$ 31,579	$ 66,226
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	126,641	109,912	85,457
Accretion expense	2,251	–	–
Gain on settlement of asset retirement obligations	(464)	–	–
Deferred income tax expense	22,138	18,063	36,977
Cumulative effect of change in accounting principle	3,527	–	–
Other	364	881	549
Change in operating assets and liabilities:			
Accounts receivable	7,505	(13,443)	21,465
Accounts payable and accrued liabilities	(2,099)	7,726	(3,216)
Other assets	1,635	(759)	1,979
Net cash provided by operating activities	198,110	153,959	209,437
CASH FLOWS FROM INVESTING ACTIVITIES:			
Oil and gas properties	(264,358)	(356,601)	(287,225)
Proceeds from sale of oil and gas property and equipment	1,148	–	–
Purchases of other property and equipment	(2,848)	(7,216)	(1,603)
Purchases of short-term investments	–	–	(29,627)
Sales of short-term investments	–	–	52,014
Net cash used in investing activities	(266,058)	(363,817)	(266,441)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	50,000	37,000	–
Payments on borrowings	–	(37,000)	–
Proceeds from issuance of common stock	–	227,873	–
Debt issue costs	(1,416)	–	–
Common stock issuance costs	-	(489)	–
Proceeds from exercise of stock options	2,136	956	7,155
Net cash provided by financing activities	50,720	228,340	7,155
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(17,228)	18,482	(49,849)
CASH AND CASH EQUIVALENTS, beginning of year	32,543	14,061	63,910
CASH AND CASH EQUIVALENTS, end of year	$ 15,315	$ 32,543	$ 14,061
SUPPLEMENTAL CASH FLOW DISCLOSURES:			
Cash paid for interest, net of amounts capitalized	$ 570	$ 468	$ 190
Cash paid (received) for income taxes, net	$ 440	$ (300)	$ 275

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION:

Spinnaker Exploration Company ("Spinnaker" or the "Company") was formed in 1996 and engages in the exploration, development and production of oil and gas 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.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

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 as of 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 oil and gas properties. Oil and gas 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.

Other Current Assets

Other current assets include unamortized debt financing costs of $0.6 million and $0.3 million as of December 31, 2003 and 2002, respectively. Other non-current assets include unamortized debt financing costs of $1.1 million and $0.3 million as of December 31, 2003 and 2002, respectively. 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 $0.4 million, $0.3 million and $0.2 million for the years ended December 31, 2003, 2002 and 2001, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

Full Cost Method of Accounting

The Company uses the full cost method of accounting for its investments in oil and gas properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of exploring for and developing oil and gas are capitalized. 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, completions, platforms, facilities, pipelines and the costs related to the retirement of these assets. Costs associated with production and general corporate activities are expensed in the period incurred. Sales of oil and gas 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 oil and gas reserves. Substantially all the Company's exploration activities are conducted jointly with others and, accordingly, the oil and gas property balances reflect only its proportionate interest in such activities.

Depreciation, Depletion and Amortization

The Company computes the provision for DD&A of oil and gas 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 and estimated salvage values associated with future asset retirement obligations.

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 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.

As of December 31, 2003, the Company excluded from the amortization base estimated future expenditures of $29.5 million associated with common development costs for its deepwater discovery at Green Canyon 338/339/382 ("Front Runner"). This estimate of future expenditures associated with common development costs is based on existing proved reserves to total proved reserves expected to be established upon completion of the Front Runner project.

Full Cost Ceiling

Capitalized costs of oil and gas properties, net of accumulated DD&A, asset retirement obligations and related deferred taxes, are limited to the estimated future net cash flows from proved oil and gas reserves, including the effects of hedging activities in place as of December 31, 2003, discounted at 10%, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (full cost ceiling). If capitalized costs of the full cost pool exceed the ceiling limitation, the excess is charged to expense.

Unproved Properties

The costs associated with unproved properties and properties under development are not initially included in the amortization base and relate to unevaluated leasehold acreage and delay rentals, seismic data, wells in-progress and wells pending determination. Unevaluated leasehold costs and delay rentals 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. Unevaluated leasehold costs and delay rentals are transferred to the amortization base if a reduction in value has occurred. The costs of seismic data are transferred to the amortization base using the sum-of-the-year's-digits method over a period of six years. The costs associated with wells in-progress and wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. The costs of drilling exploratory dry holes and associated leasehold costs are included in the amortization base immediately upon determination that the well is unsuccessful.

Of the $151.2 million of net unproved property costs as of December 31, 2003 excluded from the amortizable base, net costs of $9.9 million, $38.4 million and $19.7 million were incurred in 2003, 2002 and 2001, respectively, and $83.2 million was incurred prior to 2001. The majority of the costs will be evaluated over the next five years.

Leasehold Costs

In June 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 141, "Business Combinations," which requires the use of the purchase method of accounting for business combinations initiated after June 30, 2001 and eliminates the pooling-of-interests method. In July 2001, the FASB also issued SFAS No. 142, "Goodwill and Other Intangible Assets," which discontinues the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review of impairment. The new standard also requires that, at a minimum, all intangible assets be aggregated and presented as a separate line item in the balance sheet. The adoption of SFAS No. 141 and 142 had no impact on the Company's financial position or results of operations.

A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141 and 142 to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 141 requires registrants to classify the costs of mineral rights associated with extracting oil and gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, the Company has included the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties. If it is ultimately determined that SFAS No. 141 requires oil and gas companies to classify costs of mineral rights associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, the Company would be required to reclassify approximately $72.2 million and $59.0 million as of December 31, 2003 and 2002, respectively, from oil and gas properties to a separate intangible assets line item. These costs include those to acquire contract-based drilling and mineral use rights such as delay rentals, lease bonuses, commission and brokerage fees and other leasehold costs. The Company's cash flows and results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with full cost accounting rules. Further, the Company does not believe the classification of the costs of mineral rights associated with extracting oil and gas as intangible assets would have any impact on the Company's compliance with covenants under its revolving credit agreement.

Spinnaker will continue to classify its oil and gas leasehold costs as tangible oil and gas properties until further guidance is provided. The Company anticipates there will be no effect on its results of operations or cash flows.

Capitalized Employee and Other General and Administrative Costs

Under the full cost method of accounting, certain costs are capitalized that are directly identified with acquisition, exploration and development activities. These capitalized costs include salaries, employee benefits, costs of consulting services and other related costs and do not include costs related to production, general corporate overhead or similar activities. Spinnaker capitalized employee and other general and administrative costs of $6.7 million, $5.9 million and $5.1 million in 2003, 2002 and 2001, respectively.

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.

The costs associated with seismic hardware and software are included in other property and equipment. These costs are amortized into the full cost pool using the straight-line method over three years. Amortization was $2.1 million, $1.5 million and $0.5 million in 2003, 2002 and 2001, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

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 settlements in volumes or cash, as required by applicable contracts. Imbalances included in accounts receivable were $0.9 million and $0.6 million as of December 31, 2003 and 2002, respectively. Imbalances included in accrued liabilities were $4.1 million and $2.5 million as of December 31, 2003 and 2002, respectively.

Income Taxes

Under 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-Based Compensation

SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure," amends SFAS No. 123 to provide alternative methods of transition for an entity that voluntarily changes to the fair value based method of accounting for stock-based employee compensation and to require prominent disclosure about the effects on reported net income of an entity's accounting policy decisions with respect to stock-based employee compensation. SFAS No. 148 amends Accounting Principles Board ("APB") Opinion No. 28, "Interim Financial Reporting," to require disclosure about those effects in interim financial information.

SFAS No. 123, "Accounting for Stock-Based Compensation," 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 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. In accordance with APB Opinion No. 25, compensation expense related to stock-based compensation was $0, $0.2 million and $0.1 million in 2003, 2002 and 2001, 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, the Company's pro forma net income and pro forma net income per common share would have been as follows (in thousands, except per share amounts):

Year Ended December 31,	2003	2002	2001
Net income, as reported	$ 36,612	$ 31,579	$ 66,226
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	–	114	73
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(9,375)	(8,902)	(8,920)
Pro forma net income	$ 27,237	$ 22,791	$ 57,379
Net income per common share:			
Basic, as reported	$ 1.10	$ 1.00	$ 2.45
Basic, pro forma	$ 0.82	$ 0.72	$ 2.12
Diluted, as reported	$ 1.08	$ 0.97	$ 2.34
Diluted, pro forma	$ 0.79	$ 0.70	$ 2.02

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 2003, 2002 and 2001 as follows:

Year Ended December 31,	2003	2002	2001
Risk-free interest rate	3.18% – 4.48%	3.98% – 5.28%	4.85% – 5.57%
Volatility factor	31.7%	62.2%	43.0%
Dividend yield	0%	0%	0%
Expected life of the options (years)	3.5	4.0	4.0

Financial Instruments and Price Risk Management Activities

At December 31, 2003, 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 cashless collars and are placed with major trading counterparties.

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 items 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 (loss) of $27.1 million, representing the fair market value of the derivatives as of January 1, 2001, net of deferred income taxes of $14.6 million.

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. 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 & Poor's 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% 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 Enron Corp. and its subsidiaries filed for bankruptcy in December 2001. Spinnaker did not receive payment for fixed price swap contracts totaling $2.1 million, which were 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 $3.2 million related to these receivables.

New Accounting Pronouncements

Effective January 1, 2003, Spinnaker adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires entities to record a liability for asset retirement obligations at fair value in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. As of January 1, 2003, the Company recorded asset retirement costs of $21.4 million and asset retirement obligations of $26.0 million. The cumulative effect of change in accounting principle was $3.5 million, after taxes of $2.0 million.

The reconciliation of the beginning and ending asset retirement obligations as of December 31, 2003 is as follows (in thousands):

Asset retirement obligations, as of December 31, 2002	$ –
Liabilities upon adoption of SFAS No. 143 on January 1, 2003	25,954
Liabilities incurred	9,365
Liabilities settled[1]	(3,858)
Accretion expense	2,251
Revisions in estimated cash flows	(718)
Asset retirement obligations, as of December 31, 2003	$ 32,994

[1] The actual cost of the abandonments was approximately $3.4 million, resulting in a gain on settlement of asset retirement obligations of approximately $0.5 million.

The following table summarizes the pro forma net income and earnings per share for the years ended December 31, 2002 and 2001 as if SFAS No. 143 had been adopted on January 1, 2000 (in thousands, except per share amounts):

Year Ended December 31,	2002	2001
Net income:		
As reported	$ 31,579	$ 66,226
Pro forma	30,419	65,084
Net income per share, as reported:		
Basic	$ 1.00	$ 2.45
Diluted	$ 0.97	$ 2.34
Net income per share, pro forma:		
Basic	$ 0.96	$ 2.40
Diluted	$ 0.93	$ 2.29

The following table summarizes pro forma asset retirement obligations as of December 31, 2002 and 2001 as if SFAS No. 143 had been adopted on January 1, 2000 (in thousands):

As of December 31,	2002	2001
Asset retirement obligations, pro forma	$ 25,949	$ 22,020

3. ACCOUNTS RECEIVABLE, OTHER CURRENT ASSETS AND ACCRUED LIABILITIES AND OTHER:

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

As of December 31,	2003	2002
Accounts receivable:		
Natural gas and oil sales [1]	$ 21,015	$ 24,434
Joint interest billings	6,496	10,430
Insurance claims receivable	2,792	3,127
Hedging receivable [1]	2,093	2,093
Oil and gas imbalances	859	569
Other receivables	44	151
Allowance for doubtful accounts [1]	(3,232)	(3,232)
Total accounts receivable	$ 30,067	$ 37,572
Other current assets:		
Prepaid insurance	$ 1,937	$ 648
Deferred tax assets associated with hedging activities	972	7,170
Prepaid debt financing costs	575	301
Drilling advances	65	2,060
Other	644	1,259
Total other current assets	$ 4,193	$ 11,438
Accrued liabilities and other:		
Accrued liabilities	$ 56,802	$ 36,011
Oil and gas imbalances	4,072	2,531
Total accrued liabilities and other	$ 60,874	$ 38,542

[1] The Company had in place both financial hedge and physical contracts with Enron North America Corp. at the time Enron Corp. and its subsidiaries filed for bankruptcy in December 2001. Spinnaker did not receive payment for fixed price swap contracts totaling $2.1 million, which were 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 $3.2 million related to these receivables.

4. DEBT:

On December 28, 2001, the Company entered into an unsecured $200.0 million credit facility ("Credit Facility") with a group of seven banks. The borrowing base of the three-year Credit Facility was re-determined on a semi-annual basis. The banks and the Company also had the option to request one additional re-determination each year. The banks could also require a borrowing base re-determination if they permitted the sale, transfer or disposition of assets included in the borrowing base valued in excess of $20.0 million. The banks determined the borrowing base in their sole discretion and in their usual and customary manner. The amount of the borrowing base was a function of the banks' view of the Company's reserve profile, future commodity prices and projected cash flows. The borrowing base was $100.0 million as of December 18, 2003. The Company had the option to elect to use a base interest rate as described below or the London Interbank Offered Rate ("LIBOR") plus, for each such rate, a spread based on the percentage of the borrowing base used at that time. The base interest rate under the Credit Facility was a fluctuating rate of interest equal to the higher of either (i) The Toronto-Dominion Bank's base rate for dollar advances made in the United States or (ii) the Federal Funds Rate plus 0.5% per annum. The commitment fee rate ranged from 0.3% to 0.5%, depending on borrowing base usage. The Credit Facility contained various covenants and restrictive provisions.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

On December 19, 2003, Spinnaker revised and renewed the $200.0 million revolving credit agreement (the "Revolver") with a group of eight banks. The Revolver consists of two tranches, Tranche A and Tranche B, and matures on December 19, 2006. Borrowings under each tranche constitute senior indebtedness.

Tranche A is available on a revolving basis through the maturity of the Revolver, and availability is subject to the borrowing base, currently $125.0 million, as determined by the banks. Tranche B is $50.0 million, is available in multiple advances through April 1, 2005 and is not subject to the borrowing base. Borrowings under Tranche B cannot be reborrowed once repaid. Total availability under Tranche A and Tranche B cannot exceed $200.0 million. Should the borrowing base exceed $150.0 million, Tranche B would be reduced by a like amount for the period the borrowing base exceeds $150.0 million until the maturity of Tranche B. At such time Tranche B is utilized, the banks are to be provided with security interests in virtually all of Spinnaker's reserve base. Upon repayment of Tranche B, the security interests are to be released.

The borrowing base is re-determined semi-annually by the banks in their sole discretion and in their usual and customary manner. The banks and the Company also have the right to request one additional re-determination annually. The amount of the borrowing base is a function of the banks' view of Spinnaker's reserve profile, future commodity prices and projected cash flows. In addition to the semi-annual re-determinations, the banks have the right to re-determine the borrowing base in the event of the sale, transfer or disposition of assets included in the borrowing base exceeding $25.0 million, or $10.0 million when Tranche B is utilized.

The Company has the option to elect to use a base interest rate as described below or LIBOR plus, for each such rate, a spread based on the percentage of the borrowing base used at that time. The base rate spread ranges from 0.0% to 0.5% for Tranche A borrowings and from 2.0% to 2.75% for Tranche B borrowings. The LIBOR spread ranges from 1.25% to 2.0% for Tranche A borrowings and from 3.0% to 3.75% for Tranche B borrowings. The base interest rate under the Revolver is a fluctuating rate of interest equal to the higher of either (i) The Toronto-Dominion Bank's base rate for dollar advances made in the United States or (ii) the Federal Funds Rate plus 0.5% per annum. The commitment fee rate ranges from 0.375% to 0.5%, depending on the borrowing base usage for Tranche A and is 0.625% for Tranche B.

The Revolver also includes the following restrictions and covenants:

- Other debt is prohibited except that senior debt may not exceed $10.0 million ($5.0 million when Tranche B is used), vendor indebtedness for the purchase of seismic data may not exceed $25.0 million, subordinated debt is permitted subject to certain conditions and a lease transaction involving the Front Runner spar is specifically permitted.
- Liens are generally prohibited; however, Spinnaker may grant a lien in the purchase of seismic data and pledges and deposits to secure hedging arrangements not to exceed $15.0 million.
- Dividends and stock buy-backs exceeding $10.0 million are prohibited in any fiscal year.
- The ratio of debt to EBITDA may not exceed 2.50 to 1.00.
- The ratio of current assets to current liabilities may not be less than 1.00 to 1.00. For purposes of the calculation, availability under the Revolver is added to current assets and maturities of the Revolver are excluded from current liabilities. Hedging assets and liabilities are also excluded from this calculation.
- Spinnaker's tangible net worth is required to exceed 80% of the level at September 30, 2003, plus 50% of net income with certain non-cash gains and losses excluded from net income, plus 75% of future equity issuances.
- Spinnaker's hedging transactions must not exceed 66⅔% of estimated future production for the next 18 months and 33⅓% for the period 19 to 36 months from the date of the transaction. There are also credit rating restrictions on counterparties as well as concentration limits.

On December 31, 2003, the Company had outstanding borrowings of $50.0 million and was in compliance with the covenants and restrictive provisions under the Revolver. Subsequent to December 31, 2003, the Company borrowed an additional $25.0 million and expects to incur additional borrowings under the Revolver in 2004.

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 April 3, 2002, the Company completed a public offering of 5,750,000 shares of Common Stock at $41.50 per share, including the over-allotment option consisting of 750,000 shares. After payment of underwriting discounts and commissions, the Company received net proceeds of $227.9 million.

Spinnaker has an effective shelf registration statement relating to the potential public offer and sale by the Company or certain of its affiliates of up to $500.0 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.

6. STOCK PLANS:

Officers, directors and employees have been granted options to purchase Common Stock under stock plans adopted in 1998, 1999, 2000, 2001 and 2003. Stock option grants generally vest ratably over four years, with 20% vesting on the date of grant and 20% vesting on the anniversary date of the grant in each of the succeeding four years. In the event of certain significant changes in control of the Company, all options then outstanding generally will become immediately exercisable in full. Following is a description of the major provisions of each stock plan.

2003 Stock Option Plan ("2003 Plan")

Stockholders approved the 2003 Plan in May 2003. The number of shares of Common Stock that may be issued under the 2003 Plan may not exceed 1,650,000 shares. The exercise price of each option equals 105% of the fair market value of Spinnaker's Common Stock on the date of grant. The maximum number of shares of Common Stock that may be subject to awards granted under the 2003 Plan to any one individual during any calendar year may not exceed 300,000 shares. The options expire after five years.

2001 Stock Incentive Plan ("2001 Plan")

Stockholders approved the 2001 Plan in May 2001. The number of shares of Common Stock that may be issued under the 2001 Plan may not exceed 1,500,000 shares. The exercise price of each option equals the fair market value of Spinnaker's Common Stock on the date of grant. The maximum number of shares of Common Stock that may be subject to awards granted under the 2001 Plan to any one individual during any calendar year may not exceed 300,000 shares. The options expire after ten years.

2000 Stock Option Plan ("2000 Plan")

The Board of Directors of Spinnaker adopted the 2000 Plan in November 2000. 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. The exercise price of each option equals the fair market value of Spinnaker's Common Stock on the date of grant. The options expire after ten years.

1999 Stock Incentive Plan ("1999 Plan")

Stockholders approved the 1999 Plan in September 1999. The number of shares of Common Stock that may be issued under the 1999 Plan may not exceed 1,300,000 shares. The exercise price of each option equals the fair market value of Spinnaker's Common Stock on the date of grant. 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 shares. The options expire after ten years.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

Adjunct Stock Option Plan ("Adjunct Plan")

Stockholders approved the Adjunct Plan in connection with the 1999 Plan. The number of shares of Common Stock that may be issued under the Adjunct Plan may not exceed 21,920. The exercise price of each option equals the fair market value of Spinnaker's Common Stock on the date of grant. The options expire after ten years.

1998 Stock Option Plan ("1998 Plan")

Stockholders approved the 1998 Plan in January 1998. The 1998 Plan was amended and restated in September 1999 and authorized the issuance of 2,673,242 shares of Common Stock. The exercise price of each option equals the fair market value of Spinnaker's Common Stock on the date of grant. The options expire after ten years.

Presented below is a summary of stock option activity.

	2003		2002		2001	
	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	4,386,533	$ 23.87	4,062,556	$ 22.08	3,718,886	$ 13.80
Granted	1,288,000	23.81	450,000	35.82	1,242,800	37.90
Exercised	(186,961)	11.43	(119,433)	8.01	(810,991)	8.82
Forfeited	(56,669)	32.26	(6,590)	27.64	(88,139)	17.57
Outstanding, end of year	5,430,903	$ 24.19	4,386,533	$ 23.87	4,062,556	$ 22.08
Exercisable, end of year	3,558,639	$ 21.66	2,845,250	$ 19.30	2,273,548	$ 16.16
Available for grant, end of year	623,204		204,535		648,545	
Weighted average fair value of options granted during the year	$ 7.78		$ 26.83		$ 23.76	

The Company transferred treasury shares to certain employees in connection with their exercises of 2,300, 2,944 and 2,128 options in 2003, 2002 and 2001, respectively. Options to purchase 1,240 shares of Common Stock were forfeited during 2002 and 1999 and are not currently available for future grants due to exercise price restrictions under the 1998 Plan.

At December 31, 2003, 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	461,799	$ 4.95	461,799	$ 4.95	3.2
$ 14.50 – $ 16.13	1,651,774	15.36	1,586,864	15.33	4.7
$ 21.58 – $ 28.16	1,546,700	24.14	497,250	24.88	4.4
$ 30.38 – $ 36.81	205,220	32.33	102,576	32.26	7.3
$ 37.35 – $ 38.63	1,372,710	37.84	795,890	37.85	7.4
$ 39.35 – $ 42.06	192,700	40.50	114,260	40.67	7.6
	5,430,903		3,558,639		

7. EARNINGS PER SHARE:

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

Year Ended December 31,	2003	2002	2001
Numerator:			
Net income available to common stockholders	$ 36,612	$ 31,579	$ 66,226
Denominator:			
Basic weighted average number of shares	33,234	31,695	27,079
Dilutive securities:			
Stock options	646	958	1,281
Diluted adjusted weighted average number of shares and assumed conversions	33,880	32,653	28,360
Net income per common share:			
Basic	$ 1.10	$ 1.00	$ 2.45
Diluted	$ 1.08	$ 0.97	$ 2.34

For the years ended December 31, 2003, 2002 and 2001, 2,361,630, 1,680,640 and 113,200 stock options that could potentially dilute earnings per share are excluded from the calculations as they were anti-dilutive.

8. MAJOR CUSTOMERS:

The Company had natural gas and oil sales to Cinergy Marketing & Trading, LP, Sequent Energy Management, L.P., Shell Trading (US) Company and Duke Energy Trade and Marketing LLC accounting for approximately 41%, 22%, 14% and 10%, respectively, of total natural gas and oil revenues, excluding the effects of hedging activities, for the year ended December 31, 2003. The Company had natural gas and oil sales to Duke Energy Trade and Marketing LLC, Cinergy Marketing & Trading, LP, Equiva Trading Company and Kinder Morgan Ship Channel Pipeline LP accounting for approximately 52%, 13%, 11% and 11%, respectively, of total natural gas and oil revenues, excluding the effects of hedging activities, for the year ended December 31, 2002. The Company had natural gas and oil sales to Enron North America Corp., Tejas Gas Marketing, LLC, Reliant Energy Services, Inc. and Bridgeline Gas Marketing LLC accounting for approximately 32%, 23%, 21% and 17%, respectively, of total natural gas and oil revenues, excluding the effects of hedging activities, for the year ended December 31, 2001.

9. RELATED-PARTY TRANSACTIONS:

The Company incurred charges of approximately $7.5 million, $16.1 million and $16.3 million in 2003, 2002 and 2001, respectively, from affiliates of Baker Hughes Incorporated, an oilfield services company of which Mr. Michael E. Wiley, a director of Spinnaker, serves as Chairman of the Board, Chief Executive Officer and President. The Company incurred charges of approximately $0.1 million, $0.1 million and $0.1 million in 2003, 2002 and 2001, respectively, from Cooper Cameron Corporation, an oilfield services company of which Mr. Sheldon R. Erikson, a director of Spinnaker, serves as Chairman of the Board, Chief Executive Officer and President. These amounts represent less than 1% of both Baker Hughes' and Cooper Cameron's total revenues. The Company incurred charges of approximately $0.1 million and $0.2 million in 2003 and 2001, respectively, from National-Oilwell, Inc., an oilfield services company. Mr. Roger L. Jarvis, Chairman of the Board, Chief Executive Officer and President of Spinnaker, has served as a director of National-Oilwell, Inc. These amounts represent less than 1% of each company's total revenues.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

10. INCOME TAXES:

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

As of December 31,	2003	2002
Deferred income tax liabilities:		
Basis differences in oil and gas properties	$ 183,350	$ 156,588
Total deferred income tax liabilities	183,350	156,588
Deferred income tax assets:		
Net operating losses	$ 96,298	$ 92,650
Hedging activities	972	7,170
Other	6,025	2,112
Total deferred income tax assets	103,295	101,932
Net deferred income tax liabilities	80,055	54,656
Deferred tax assets reported in other current assets	972	7,170
Deferred income taxes	$ 81,027	$ 61,826

Tax benefits of $1.0 million and $1.4 million associated with the exercise of non-qualified stock options during the years ended December 31, 2003 and 2002 are reflected as a component of equity. The net deferred income tax liabilities include deferred tax assets of $1.0 million and $7.2 million related to the tax effect of the fair market value of derivatives as of December 31, 2003 and 2002, respectively, as required by SFAS No. 133, as amended. Upon adoption of SFAS No. 143 on January 1, 2003, the Company recorded a cumulative effect of change in accounting principle of $3.5 million, after taxes of $2.0 million.

As of December 31, 2003, the Company had approximately $268.0 million of net operating loss carryforwards ("NOLs") that will begin expiring in 2018. For federal income tax purposes, certain limitations are imposed on an entity's ability to utilize its NOLs in future periods if a change of control, as defined for federal income tax purposes, has occurred. In general terms, the limitation on utilization of NOLs and other tax attributes during any one year is determined by the value of an entity at the date of the change of control multiplied by the then-existing long-term, tax-exempt interest rate. The Internal Revenue Service has not yet addressed the manner of determining an entity's value. The Company has determined that, for federal income tax purposes, a change of control occurred during 2000. However, the Company does not believe such limitations will significantly impact its ability to utilize the NOLs.

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

Year Ended December 31,	2003	2002	2001
Current	$ 440	$ (300)	$ 275
Deferred	22,138	18,063	36,977
Income tax expense	$ 22,578	$ 17,763	$ 37,252

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

Year Ended December 31,	2003	2002	2001
Federal income tax expense at statutory rates	$ 21,951	$ 17,270	$ 36,217
Non-deductible expenses and other	627	493	1,035
Income tax expense	$ 22,578	$ 17,763	$ 37,252

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.

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 savings 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.

Effective January 1, 2000, the Company began matching employee contributions to the 401(k) Plan. The Company matches 100% of each participant's contributions up to 6% of the participant's annual base salary. In connection with the employer match, the Company issued 16,124 shares of Common Stock valued at $0.4 million in 2003, 9,062 shares of Common Stock valued at $0.3 million in 2002 and 5,456 shares of Common Stock valued at $0.2 million in 2001.

Leases

The Company leases administrative offices under a non-cancelable operating lease expiring in 2007. The lease agreement requires the Company to pay for utilities, maintenance and other operational expenses of the building. Additionally, the lease contains escalation clauses. The Company also leases office equipment and oil and gas equipment under non-cancelable operating leases. Rental expense was $2.2 million, $1.6 million and $0.7 million in 2003, 2002 and 2001, respectively. Minimum future obligations under non-cancelable operating leases as of December 31, 2003 for the next five years are approximately $1.5 million, $1.3 million, $1.3 million, $0.5 million and less than $0.1 million, respectively.

Summary of Contractual Obligations

The Company leases administrative offices, office equipment and oil and gas equipment under non-cancelable operating leases. Contractual obligations as of December 31, 2003 were as follows (in thousands):

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	$ 50,000	$ –	$ 50,000	$ –	$ –
Operating leases	4,628	1,470	3,154	4	–
Other contractual obligations [1]	6,275	6,275	–	–	–
Total	$ 60,903	$ 7,745	$ 53,154	$ 4	$ –

[1] Contractual obligations for seismic data acquisitions.

The Company will incur obligations in the ordinary course of business under purchase and service agreements that are not included in the table above. These obligations, among others, include estimated future development costs of approximately $177.5 million for the costs of drilling additional wells, completions, recompletions, platforms, pipelines, facilities, tie-backs and abandonments related to the proved reserves. Spinnaker's asset retirement obligations as of December 31, 2003 were $33.0 million.

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. These swap contracts and collar arrangements 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. As of December 31, 2003, Spinnaker's commodity price risk management positions in fixed price natural gas swap contracts and related fair values were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Price (Per MMBtu)	Fair Value (in thousands)
First Quarter 2004	35,000	$ 6.04	$ (235)
Second Quarter 2004	15,000	4.91	(350)
Third Quarter 2004	15,000	4.87	(370)
Fourth Quarter 2004	8,370	4.92	(245)
Year 2004	18,306	5.44	$ (1,200)

In a collar arrangement, the counterparty is required to make a payment to us for the difference between the fixed floor price and the settlement price if the settlement price is below the fixed floor price. We are required to make a payment to the counterparty for the difference between the fixed ceiling price and the settlement price if the settlement price is above the fixed ceiling price. Neither party is required to make a payment if the settlement price falls between the fixed floor and ceiling prices. As of December 31, 2003, our commodity price risk management positions in natural gas collar arrangements and related fair values were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Ceiling Price (Per MMBtu)	Weighted Average Floor Price (Per MMBtu)	Fair Value (in thousands)
First Quarter 2004	20,000	$ 6.64	$ 5.25	$ (407)
Second Quarter 2004	20,000	5.48	4.38	(375)
Third Quarter 2004	20,000	5.48	4.38	(383)
Fourth Quarter 2004	13,370	5.56	4.44	(335)
Year 2004	18,384	5.81	4.63	$ (1,500)

The Company reported net liabilities of $2.7 million and $19.9 million related to its financial derivative contracts as of December 31, 2003 and 2002, respectively. Amounts related to hedging activities were as follows (in thousands):

As of December 31,	2003	2002
Current assets:		
Hedging assets	$ 203	$ –
Deferred tax asset related to hedging activities	972	7,170
Current liabilities:		
Hedging liabilities	$ 2,903	$ 19,917
Equity:		
Accumulated other comprehensive loss	$ (1,728)	$ (12,747)

The Company recognized no ineffective component of the derivatives and net hedging gains (losses) in revenues in 2003, 2002 and 2001 as follows (in thousands):

Year Ended December 31,	2003	2002	2001
Net hedging income (loss)	$ (37,717)	$ 4,664	$ (9,580)

Based on future natural gas prices as of December 31, 2003, the Company would reclassify a net loss of $2.7 million from accumulated other comprehensive loss to earnings in 2004. 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, 2003 and 2002 are summarized as follows (in thousands, except per share amounts):

	(Unaudited) Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2003:				
Revenues	$ 71,671	$ 55,931	$ 50,138	$ 49,110
Income from operations	29,498	15,760	7,720	10,182
Net income	15,298	10,028	4,822	6,464
Net income per common share:				
Basic	$ 0.46	$ 0.30	$ 0.15	$ 0.19
Diluted	$ 0.45	$ 0.30	$ 0.14	$ 0.19
2002:				
Revenues	$ 32,600	$ 37,164	$ 51,558	$ 67,004
Income from operations	8,963	9,256	11,042	19,829
Net income	5,576	6,222	7,146	12,635
Net income per common share:				
Basic	$ 0.20	$ 0.19	$ 0.22	$ 0.38
Diluted	$ 0.20	$ 0.18	$ 0.21	$ 0.37

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

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

Capitalized Costs Related to Oil and Gas Producing Activities (In thousands)

As of December 31,	2003	2002
Capitalized costs:		
Proved properties	$ 1,175,443	$ 879,840
Unproved properties not being amortized	151,214	141,326
Total	1,326,657	1,021,166
Accumulated depreciation, depletion and amortization [1]	(394,004)	(267,744)
Net capitalized costs	$ 932,653	$ 753,422

[1] DD&A per Mcfe was $2.56, $2.12 and $1.60 in 2003, 2002 and 2001, respectively. The cumulative effect of change in accounting principle included an impact to accumulated DD&A of approximately $0.9 million.

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities (In thousands)

Year Ended December 31,	2003	2002	2001
Acquisition costs:			
Unproved	$ 20,067	$ 39,789	$ 34,524
Proved	–	–	–
Exploration costs	104,622	163,322	187,720
Development costs	181,486	139,368	80,276
Total costs incurred	$ 306,175	$ 342,479	$ 302,520

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, completions, platforms, facilities, pipelines and the costs related to the retirement of these costs. Development costs as of December 31, 2003 include asset retirement costs of $30.0 million and gain on settlement of asset retirement obligations of $0.5 million.

Costs being excluded from amortization consist of the following (in thousands):

Year Ended December 31,	Total	2003	2002	2001	2000 And Prior
Unproved property costs	$ 93,137	$ 3,300	$ 28,635	$ 22,362	$ 38,840
Exploration costs	50,210	459	11,306	(5,880)	44,325
Development costs	7,867	6,129	(1,496)	3,234	–
Total	$ 151,214	$ 9,888	$ 38,445	$ 19,716	$ 83,165

Results of Operations for Oil and Gas Producing Activities (In thousands)

Year Ended December 31,	2003	2002	2001
Revenues	$ 226,850	$ 188,326	$ 210,376
Operating expenses [1]	22,489	18,212	12,132
Depreciation, depletion and amortization	125,331	108,998	85,059
Accretion expense	2,251	–	–
Gain on settlements of asset retirement obligations	(464)	–	–
Charges related to Enron bankruptcy	–	128	3,059
Income tax expense [2]	27,807	21,956	39,645
Results of operations	$ 49,436	$ 39,032	$ 70,481

[1] Operating expenses include costs incurred to operate and maintain wells and related equipment and facilities. These costs include, among others, workover expenses, labor, materials, supplies, property taxes, insurance, severance taxes and transportation, gathering and processing expenses.

[2] Income tax expense is calculated by applying the statutory tax rate to operating profit, then adjusting for any applicable permanent tax differences or tax credits and allowances.

Proved oil and gas 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 oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can reasonably be expected to be recovered through existing wells with existing equipment and operating methods.

Reserve Quantity Information

	Natural Gas (MMcf)	Oil and Condensate (MBbls)	Natural Gas Equivalents (MMcfe)
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
Extensions, discoveries and other additions	24,666	7,678	70,733
Revisions of previous estimates [2]	(11,936)	(1,168)	(18,944)
Production	(45,180)	(1,040)	(51,419)
Proved reserves as of December 31, 2002 [1]	143,531	30,008	323,577
Extensions, discoveries and other additions	53,775	1,867	64,976
Revisions of previous estimates [3]	(2,350)	(769)	(6,962)
Production	(40,527)	(1,414)	(49,010)
Proved reserves as of December 31, 2003 [1]	154,429	29,692	332,581
Proved developed reserves:			
December 31, 2003 [1]	76,181	4,877	105,441
December 31, 2002 [1]	84,139	2,219	97,456
December 31, 2001 [1]	82,221	748	86,711
December 31, 2000	112,315	1,042	118,568

[1] Spinnaker has a 25% non-operator working interest in a significant deepwater oil discovery at Front Runner. This significant oil discovery changed Spinnaker's reserve profile. Proved oil and condensate reserves were 53%, 56% and 46% of total proved reserves as of December 31, 2003, 2002 and 2001, respectively, compared to 10% as of December 31, 2000. Of the Company's total proved reserves as of December 31, 2003, 68% were proved undeveloped reserves. Front Runner represented approximately 70% of total proved undeveloped reserves.

[2] Front Runner area reserves are subject to royalty relief on the first 87.5 million equivalent barrels of oil produced. As new reserves are added in the Front Runner area, changes in future production assumptions result in a reallocation of reserves subject to royalty relief. These reallocations resulted in downward revisions to previous estimates of approximately 671 MMcf and 1,002 MBbls, or natural gas equivalents of 6,681 MMcfe. No downward revision on any individual property exceeded 1% of proved reserves as of December 31, 2001.

[3] The 2003 revisions of previous estimates include a 6.1 Bcfe downward revision on Mississippi Canyon 496 (Zia) related to reserves originally booked below lowest known hydrocarbon. No downward revision on any individual property exceed 2% of proved reserves as of December 31, 2002.

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 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 oil and gas 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 oil and gas 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 oil and gas 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 oil and gas properties could occur in the future.

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

Year Ended December 31,	2003	2002	2001
Future cash inflows [1]	$ 1,867,760	$ 1,613,724	$ 944,861
Future operating expenses	(219,466)	(185,782)	(164,105)
Future development costs	(177,531)	(184,441)	(191,711)
Future net cash flows before income taxes	1,470,763	1,243,501	589,045
Future income taxes	(373,295)	(259,436)	(120,489)
Future net cash flows	1,097,468	984,065	468,556
10% annual discount	(293,687)	(303,267)	(139,000)
Standardized measure of discounted future net cash flows	$ 803,781	$ 680,798	$ 329,556

[1] Prices for natural gas and oil used to calculate future cash inflows were $6.29, $4.91 and $2.71 per Mcf of natural gas and $30.34, $30.50 and $19.23 per barrel of oil as of December 31, 2003, 2002 and 2001, respectively.

Principal Sources of Change in the Standardized Measure of Discounted Future Net Cash Flows (In thousands)

Year Ended December 31,	2003	2002	2001
Standardized measure, beginning of year	$ 680,798	$ 329,556	$ 899,137
Extensions and discoveries, net of related costs	212,129	215,800	198,709
Sales of natural gas and oil produced, net of production costs	(242,078)	(165,450)	(207,824)
Net changes in prices and production costs	115,793	403,728	(958,755)
Change in future development costs	(3,816)	(26,795)	(18,959)
Development costs incurred during the period that reduced future development costs	77,604	56,831	47,463
Revisions of quantity estimates	(22,578)	(57,991)	6,092
Accretion of discount	76,169	(640)	132,067
Net change in income taxes	(94,391)	(80,892)	335,952
Change in production rates and other	4,151	6,651	(104,326)
Standardized measure, end of year	$ 803,781	$ 680,798	$ 329,556

SELECTED FINANCIAL DATA

(In thousands, except per share 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,	2003	2002	2001	2000	1999
STATEMENT OF OPERATIONS DATA:					
Revenues	$ 226,850	$ 188,326	$ 210,376	$ 121,383	$ 34,258
Expenses:					
Lease operating expenses	22,489	18,212	12,132	9,009	5,411
Depreciation, depletion and amortization – oil and gas properties	125,331	108,998	85,059	47,451	20,788
Depreciation and amortization – other	1,310	914	398	309	213
Accretion expense [1]	2,251	–	–	–	–
Gain on settlement of asset retirement obligations [1]	(464)	–	–	–	–
General and administrative	12,773	10,984	9,443	7,350	4,860
Charges related to Enron bankruptcy [2]	–	128	3,059	–	–
Stock appreciation rights expense [3]	–	–	–	–	1,651
Total expenses	163,690	139,236	110,091	64,119	32,923
Income from operations	63,160	49,090	100,285	57,264	1,335
Other income (expense):					
Interest income	201	1,014	3,574	2,908	528
Interest expense, net	(784)	(762)	(381)	(748)	(2,805)
Other	140	–	–	–	–
Total other income (expense)	(443)	252	3,193	2,160	(2,277)
Income (loss) before income taxes	62,717	49,342	103,478	59,424	(942)
Income tax expense	22,578	17,763	37,252	20,858	–
Income (loss) before cumulative effect of change in accounting principle	40,139	31,579	66,226	38,566	(942)
Cumulative effect of change in accounting principle [1][4]	(3,527)	–	–	–	(395)
Net income (loss)	36,612	31,579	66,226	38,566	(1,337)
Accrual of dividends on preferred stock	–	–	–	–	(7,911)
Net income (loss) available to common stockholders	$ 36,612	$ 31,579	$ 66,226	$ 38,566	$ (9,248)
Basic income (loss) per common share:					
Income (loss) before cumulative effect of change in accounting principle	$ 1.21	$ 1.00	$ 2.45	$ 1.70	$ (1.06)
Cumulative effect of change in accounting principle [1][4]	(0.11)	–	–	–	(0.05)
Net income (loss) per common share	$ 1.10	$ 1.00	$ 2.45	$ 1.70	$ (1.11)
Diluted income (loss) per common share:					
Income (loss) before cumulative effect of change in accounting principle	$ 1.18	$ 0.97	$ 2.34	$ 1.61	$ (1.06)
Cumulative effect of change in accounting principle [1][4]	(0.10)	–	–	–	(0.05)
Net income (loss) per common share	$ 1.08	$ 0.97	$ 2.34	$ 1.61	$ (1.11)
Weighted average number of common shares outstanding [5]:					
Basic	33,234	31,695	27,079	22,679	8,355
Diluted	33,880	32,653	28,360	24,011	8,355
SUMMARY BALANCE SHEET DATA:					
Working capital (deficit)	$ (33,168)	$ (6,359)	$ (20,654)	$ 74,005	$ 19,675
Property and equipment, net [1]	939,668	760,854	522,573	304,381	157,397
Total assets	990,582	842,715	587,316	442,704	189,553
Total equity [5]	744,061	692,977	458,492	361,259	177,102

(1) Effective January 1, 2003, Spinnaker adopted Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires entities to record a liability for asset retirement obligations at fair value in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. As of January 1, 2003, the Company recorded asset retirement costs of $21.4 million and asset retirement obligations of $26.0 million. The cumulative effect of change in accounting principle was $3.5 million, after taxes of $2.0 million.

Accretion expense is the recognition of period-to-period changes in the asset retirement obligation liability resulting from the passage of time, subsequent to the initial asset retirement obligation liability measurement.

Gain on settlement of asset retirement obligations represents the difference between the actual cost of the asset retirement and the asset retirement obligation.

(2) The Company had in place both financial hedge and physical contracts with Enron North America Corp. at the time Enron Corp. and its subsidiaries filed for bankruptcy in December 2001. Spinnaker did not receive payment for fixed price swap contracts totaling $2.1 million, which were 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 $3.2 million against these receivables.

(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 in 1999 represents the adoption of Statement of Position 98-5 "Reporting on the Costs of Start-Up Activities."

(5) On April 3, 2002, the Company completed a public offering of 5,750,000 shares of Common Stock. On August 16, 2000, the Company completed a public offering of 5,600,000 shares of Common Stock. In connection with its initial public offering in 1999, the Company issued 8,000,000 shares of Common Stock, converted all then outstanding shares of Series A Convertible Preferred Stock, par value $0.01 per share ("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.

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][3][5]
Chairman of the Board, President and Chief Executive Officer
Cooper Cameron Corporation

Jeffrey A. Harris[2][5]
Managing Director / Partner
Warburg Pincus LLC / Warburg Pincus & Co.

Michael E. McMahon[1][5][6]
Executive Counselor to the Governor on
Economic Growth and Community Development
Rhode Island Economic Development Corporation

Michael G. Morris[1][3]
Chairman of the Board, President and Chief Executive Officer
American Electric Power

Howard H. Newman[4]
Vice Chairman / Partner
Warburg Pincus LLC / Warburg Pincus & Co.

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

(1) Audit Committee
(2) Compensation Committee
(3) Nominating / Corporate Governance Committee
(4) Presiding Director
(5) Committee Chairman
(6) Audit Committee Financial Expert

CORPORATE OFFICERS

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

Scott A. Griffiths
Executive Vice President and Chief Operating Officer

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

Kelly M. Barnes
Vice President – Land

Jimmy W. Bennett
Vice President – Systems Technology and Processing

L. Scott Broussard
Vice President – Drilling and Production

Gonzalo Enciso
Vice President and Chief Geoscientist

William N. Young, III
Vice President – Marketing

Jeffrey C. Zaruba
Vice President, Treasurer and Assistant Secretary

STOCKHOLDER INFORMATION

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OUTSIDE LEGAL COUNSEL

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

INDEPENDENT AUDITORS

KPMG LLP
Houston, Texas

FORM 10-K AND OTHER REPORTS

Spinnaker files reports with the Securities and Exchange Commission ("Commission") on Forms 10-K, 10-Q and 8-K. The public may read and copy any materials that the Company files with the Commission at the Commission's public reference room at 450 Fifth Street, NW, Washington, DC 20549. The public may also access Spinnaker's annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished to the Commission pursuant to Section 13(a) or 15(d) of the Exchange Act on its internet website at www.spinnakerexploration.com, free of charge, as soon as reasonably practicable after Spinnaker electronically files or furnishes such material with or to the Commission.

Spinnaker's Board of Directors has adopted corporate governance guidelines, committee charters and a code of business conduct and ethics for directors, officers and employees. Each of these documents is available on the Company's internet website at www.spinnakerexploration.com and available in print, free of charge, upon written request to Spinnaker Exploration Company, 1200 Smith Street, Suite 800, Houston, Texas 77002, Attention: Corporate Secretary.

MARKET INFORMATION

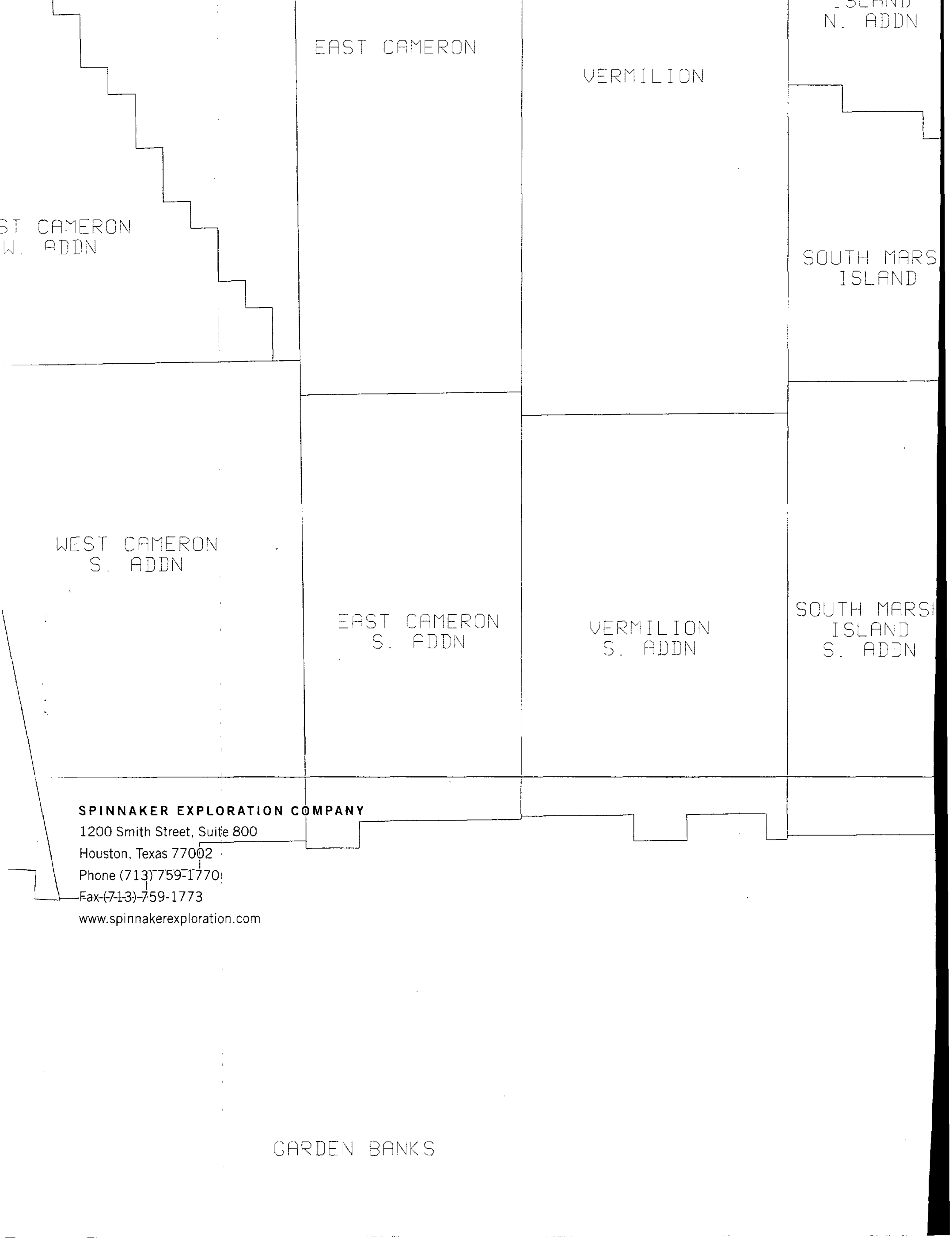
Spinnaker's common stock trades on the New York Stock Exchange under the symbol "SKE." The following table sets forth the range of high and low sales prices per share of common stock for each calendar quarter.

	Sales Price	
	High	Low
2002:		
First Quarter	$ 44.64	$ 34.45
Second Quarter	$ 44.89	$ 35.77
Third Quarter	$ 36.90	$ 24.46
Fourth Quarter	$ 29.71	$ 18.45
2003:		
First Quarter	$ 22.70	$ 17.15
Second Quarter	$ 28.01	$ 18.01
Third Quarter	$ 26.50	$ 19.98
Fourth Quarter	$ 33.52	$ 23.97
2004:		
First Quarter (through March 19, 2004)	$ 36.99	$ 31.93

As of March 19, 2004, there were 37 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 Wednesday, May 5, 2004, at the DoubleTree Hotel at Allen Center, 400 Dallas Street at Bagby, Houston, Texas.



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