SPINNAKER EXPLORATION CO
Form 10-Q
August 06, 2004
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

x **Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the quarterly period ended June 30, 2004.

¨ **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period from ______ to ______.

Commission file number 001-16009

SPINNAKER EXPLORATION COMPANY

(Exact name of registrant as specified in its charter)

Delaware	**76-0560101**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

1200 Smith Street, Suite 800

Houston, Texas	**77002**
(Address of principal executive offices)	**(Zip Code)**

(713) 759-1770

(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes x No ¨

The number of shares outstanding of the registrant s common stock, par value $0.01 per share, on August 5, 2004 was 33,898,340.

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SPINNAKER EXPLORATION COMPANY

Form 10-Q

For the Three and Six Months Ended June 30, 2004

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Cautionary Statement About Forward-Looking Statements

Some of the information in this quarterly report on Form 10-Q 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 f 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 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 quarterly 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 in the Company s annual report on Form 10-K for the year ended December 31, 2003.

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SPINNAKER EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share data)

	As of June 30, 2004	As of December 31, 2003
	(Unaudited)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 16,027	$ 15,315
Accounts receivable, net of allowance for doubtful accounts of $3,232 as of June 30, 2004 and December 31, 2003, respectively	53,796	30,067
Hedging assets		203
Other	4,941	4,193
Total current assets	74,764	49,778
PROPERTY AND EQUIPMENT:		
Oil and gas, on the basis of full-cost accounting:		
Proved properties	1,317,903	1,175,443
Unproved properties and properties under development, not being amortized	150,650	151,214
Other	18,365	17,309
	1,486,918	1,343,966
Less Accumulated depreciation, depletion and amortization	(475,590)	(404,298)
Total property and equipment	1,011,328	939,668
OTHER ASSETS	854	1,136
Total assets	$ 1,086,946	$ 990,582
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 26,869	$ 18,723
Accrued liabilities and other	45,904	60,874
Hedging liabilities	6,319	2,903
Asset retirement obligations, current portion	1,139	446
Total current liabilities	80,231	82,946
LONG-TERM DEBT	93,000	50,000
ASSET RETIREMENT OBLIGATIONS	35,123	32,548
DEFERRED INCOME TAXES	95,834	81,027
COMMITMENTS AND CONTINGENCIES EQUITY:		
Preferred stock, $0.01 par value; 10,000,000 shares authorized; no shares issued and outstanding as of June 30, 2004 and December 31, 2003, respectively		
Common stock, $0.01 par value; 50,000,000 shares authorized; 33,795,935 shares issued and 33,788,795 shares outstanding as of June 30, 2004 and 33,385,248 shares issued and 33,374,844 shares	338	334

outstanding as of December 31, 2003		
Additional paid-in capital	609,191	599,532
Retained earnings	177,291	145,949
Less: Treasury stock, at cost, 7,140 and 10,404 shares as of June 30, 2004 and December 31, 2003, respectively	(18)	(26)
Accumulated other comprehensive loss	(4,044)	(1,728)
Total equity	782,758	744,061
Total liabilities and equity	$ 1,086,946	$ 990,582

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

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SPINNAKER EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except share data)

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
REVENUES	$ 79,824	$ 55,931	$ 139,615	$ 127,602
EXPENSES:				
Lease operating expenses	6,530	5,208	11,243	10,701
Depreciation, depletion and amortization oil and gas properties	40,403	31,242	69,404	64,077
Depreciation and amortization other	350	322	696	633
Accretion expense	538	569	1,254	1,064
Gain on settlement of asset retirement obligations		(171)	(126)	(171)
General and administrative	4,227	3,001	7,725	6,040
Total expenses	52,048	40,171	90,196	82,344
INCOME FROM OPERATIONS	27,776	15,760	49,419	45,258
OTHER INCOME (EXPENSE):				
Interest income	36	62	68	127
Interest expense, net	(304)	(153)	(515)	(302)
Total other income (expense)	(268)	(91)	(447)	(175)
INCOME BEFORE INCOME TAXES	27,508	15,669	48,972	45,083
Income tax expense	9,903	5,641	17,630	16,230
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	17,605	10,028	31,342	28,853
Cumulative effect of change in accounting principle				(3,527)
NET INCOME	$ 17,605	$ 10,028	$ 31,342	$ 25,326
BASIC INCOME PER COMMON SHARE:				
Income before cumulative effect of change in accounting principle	$ 0.52	$ 0.30	$ 0.93	$ 0.87
Cumulative effect of change in accounting principle				(0.11)
NET INCOME PER COMMON SHARE	$ 0.52	$ 0.30	$ 0.93	$ 0.76
DILUTED INCOME PER COMMON SHARE:				
Income before cumulative effect of change in accounting principle	$ 0.51	$ 0.30	$ 0.90	$ 0.85
Cumulative effect of change in accounting principle				(0.10)

NET INCOME PER COMMON SHARE	$ 0.51	$ 0.30	$ 0.90	$ 0.75
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:				
Basic	33,719	33,207	33,633	33,199
Diluted	34,779	33,859	34,708	33,776

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

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SPINNAKER EXPLORATION COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

(Unaudited)

	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 31,342	$ 25,326
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	70,100	64,710
Accretion expense	1,254	1,064
Gain on settlement of asset retirement obligations	(126)	(171)
Deferred income tax expense	17,630	15,970
Cumulative effect of change in accounting principle		3,527
Other	415	132
Change in operating assets and liabilities:		
Accounts receivable	(23,729)	10,657
Accounts payable and accrued liabilities	4,653	5,891
Other assets	938	3,034
Net cash provided by operating activities	102,477	130,140
CASH FLOWS FROM INVESTING ACTIVITIES:		
Oil and gas properties	(150,041)	(144,203)
Proceeds from sale of oil and gas property and equipment		1,148
Purchases of other property and equipment	(1,056)	(757)
Net cash used in investing activities	(151,097)	(143,812)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	43,000	
Debt issue costs	(101)	
Proceeds from exercise of stock options	6,433	347
Net cash provided by financing activities	49,332	347
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	712	(13,325)
CASH AND CASH EQUIVALENTS, beginning of year	15,315	32,543
CASH AND CASH EQUIVALENTS, end of period	$ 16,027	$ 19,218
SUPPLEMENTAL CASH FLOW DISCLOSURES:		
Cash paid for interest, net of amounts capitalized	$ 1,365	$ 149
Cash paid for income taxes	$	$ 260

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

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SPINNAKER EXPLORATION COMPANY

Notes to Interim Consolidated Financial Statements (Unaudited)

June 30, 2004

1. Basis of Presentation

The accompanying unaudited consolidated financial statements of Spinnaker Exploration Company (Spinnaker or the Company) have been prepared in accordance with generally accepted accounting principles for interim financial information and the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by accounting principles generally accepted in the United States for complete financial statements. In the opinion of management, all adjustments (consisting only of normal and recurring adjustments) necessary to present a fair statement of the results for the periods included herein have been made and the disclosures contained herein are adequate to make the information presented not misleading. Interim period results are not necessarily indicative of results of operations or cash flows for a full year. These consolidated financial statements and the notes thereto should be read in conjunction with the Company s Annual Report on Form 10-K for the year ended December 31, 2003.

2. Summary of Significant Accounting Policies

Stock-Based Compensation

Statement of Financial Accounting Standards (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 Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations. Accordingly, compensation cost for stock options is measured as the excess, if any, of the fair value of the common stock, 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 $0.2 million and $0 in the second quarter of 2004 and 2003, respectively, and $0.2 million and $0 in the first six months of 2004 and 2003, 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 share of Common Stock would have been as follows (in thousands, except per share amounts):

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2004	**2003**	**2004**	**2003**
Net income, as reported	$ 17,605	$ 10,028	$ 31,342	$ 25,326
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	126		126	
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(2,115)	(3,021)	(4,654)	(4,867)

Pro forma net income	$ 15,616	$ 7,007	$ 26,814	$ 20,459
Net income per common share:				
Basic, as reported	$ 0.52	$ 0.30	$ 0.93	$ 0.76
Basic, pro forma	$ 0.46	$ 0.21	$ 0.80	$ 0.62
Diluted, as reported	$ 0.51	$ 0.30	$ 0.90	$ 0.75
Diluted, pro forma	$ 0.43	$ 0.20	$ 0.75	$ 0.60

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

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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 and the extractive industries 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, the Company would be required to reclassify approximately $85.8 million and $72.2 million as of June 30, 2004 and December 31, 2003, 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 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. Spinnaker will continue to classify its oil and gas leasehold costs as tangible oil and gas properties until further guidance is provided.

3. Asset Retirement Obligations

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 for the three and six months ended June 30, 2004 and 2003 was as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	**2003**	**2004**	**2003**
Asset retirement obligations, beginning of period	$ 33,974	$ 27,275	$ 32,994	$
Liabilities upon adoption of SFAS No. 143 on January 1, 2003				25,954
Liabilities incurred	2,261	5,019	2,834	5,845
Liabilities settled		(2,638)		(2,638)
Accretion expense	538	569	1,254	1,064
Revisions in estimated cash flows	(511)	(108)	(820)	(108)
Asset retirement obligations, end of period	$ 36,262	$ 30,117	$ 36,262	$ 30,117

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4. Earnings Per Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
Numerator:				
Net income available to common stockholders	$ 17,605	$ 10,028	$ 31,342	$ 25,326
Denominator:				
Basic weighted average number of shares	33,719	33,207	33,633	33,199
Dilutive securities:				
Stock options	1,060	652	1,075	577
Diluted adjusted weighted average number of shares and assumed conversions	34,779	33,859	34,708	33,776
Basic income per common share:				
Income before cumulative effect of change in accounting principle	$ 0.52	$ 0.30	$ 0.93	$ 0.87
Cumulative effect of change in accounting principle				(0.11)
Net income per common share	$ 0.52	$ 0.30	$ 0.93	$ 0.76
Diluted income per common share:				
Income before cumulative effect of change in accounting principle	$ 0.51	$ 0.30	$ 0.90	$ 0.85
Cumulative effect of change in accounting principle				(0.10)
Net income per common share	$ 0.51	$ 0.30	$ 0.90	$ 0.75

5. Debt

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 $140.0 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. The Company has made no borrowings under Tranche B. 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 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 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

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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 contains various restrictions and covenants.

On June 30, 2004, the Company had outstanding borrowings under Tranche A of $93.0 million and was in compliance with the covenants and restrictive provisions under the Revolver. Subsequent to June 30, 2004, the Company had no additional borrowings; however, the Company expects to incur additional borrowings under Tranche A of the Revolver in the remainder of 2004.

6. 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 June 30, 2004, 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)
Third Quarter 2004	30,000	$ 5.13	$ (2,826)
Fourth Quarter 2004	8,370	4.92	(1,100)
First Quarter 2005	5,000	7.05	144
Total			$ (3,782)

In a collar arrangement, the counterparty is required to make a payment to the Company for the difference between the fixed floor price and the settlement price if the settlement price is below the fixed floor price. The Company is 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 price. As of June 30, 2004, Spinnaker s commodity price risk management positions in natural gas collar arrangements and related fair values were as follows:

Period	Average Daily	Weighted Average Ceiling Price (Per MMBtu)	Weighted Average Floor Price (Per MMBtu)	Fair Value (in thousands)

	Volume (MMBtus)			
Third Quarter 2004	20,000	$ 5.48	$ 4.38	$ (1,413)
Fourth Quarter 2004	18,370	6.56	4.73	(1,124)
Total				$ (2,537)

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The Company reported net liabilities of $6.3 million and $2.7 million related to its financial derivative contracts as of June 30, 2004 and December 31, 2003, respectively. Amounts related to hedging activities were as follows (in thousands):

	As of June 30, 2004	As of December 31, 2003
Current assets:		
Hedging assets	$	$ 203
Deferred tax asset related to hedging activities	$ 2,275	$ 972
Current liabilities:		
Hedging liabilities	$ 6,319	$ 2,903
Equity:		
Accumulated other comprehensive loss	$ (4,044)	$ (1,728)

The Company recognized no ineffective component of the derivatives in the three and six months ended June 30, 2004 and 2003. The Company recognized a net hedging loss in revenues in the three and six months ended June 30, 2004 and 2003 as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
Net hedging loss	$ (3,285)	$ (9,167)	$ (1,546)	$ (26,910)

Based on future natural gas prices as of June 30, 2004, the Company would reclassify a net loss of $6.4 million from accumulated other comprehensive loss to earnings in the remainder of 2004 and a gain of $0.1 million from accumulated other comprehensive loss to earnings in the first quarter of 2005. The amounts ultimately reclassified into earnings will vary due to changes in the fair value of the open derivative contracts prior to settlement.

7. Comprehensive Income

The following are components of comprehensive income (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003

Net income	$ 17,605	$ 10,028	$ 31,342	$ 25,326
Other comprehensive income (loss), net of tax:				
Net change in fair value of derivative financial instruments	(943)	(3,102)	(3,305)	(16,780)
Financial derivative settlements reclassified to income	2,102	5,867	989	17,222
Comprehensive income	$ 18,764	$ 12,793	$ 29,026	$ 25,768

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Item 2. 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 deepwater prospects, ranging from lower-risk prospects to higher-risk, higher-potential prospects.

We recognized net income of $17.6 million, or $0.51 per diluted share, in the second quarter of 2004 compared to net income of $10.0 million, or $0.30 per diluted share, in the second quarter of 2003. These financial results were impacted by 11% higher production and a 30% higher realized commodity price in the second quarter of 2004 compared to the second quarter of 2003. Our lease operating expense (LOE) rate per Mcfe in the second quarter of 2004 increased 14% to $0.48 compared to the same period in 2003, primarily due to higher LOE rates on new wells. The depreciation, depletion and amortization (DD&A) expense rate per Mcfe increased 17% in the second quarter of 2004 to $2.97 compared to the same period in 2003 primarily due to costs associated with unsuccessful drilling operations, higher finding costs and the timing of reserve recognition, as more reservoir and production information becomes available, compared to the related amortized costs. Of the total increase in the DD&A rate from the first quarter of 2004, $0.12 per Mcfe resulted from the retraction of royalty suspension volumes of 2.4 million barrels of oil (MMBbls), or 14.3 Bcfe, on Green Canyon 338/339/382 (Front Runner).

We had $16.0 million in cash and cash equivalents and outstanding borrowings under the Revolver of $93.0 million as of June 30, 2004. We have experienced and expect to continue to experience substantial capital requirements. We have incurred capital costs of approximately $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. Our working capital deficit decreased to $5.5 million as of June 30, 2004 compared to $33.2 million as of December 31, 2003. We have capital expenditure plans for 2004 totaling approximately $270.0 million. 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.

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 in size 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 and reserve recognition from these projects until after 2004.

Production

Since inception, approximately 90% of our total production has consisted of natural gas. Approximately 74% of our total production in the second quarter of 2004 was natural gas. Considering oil and condensate production from deepwater projects in 2004 and 2005, we anticipate that this concentration in natural gas production will be approximately 75% of total production in 2004 and approximately 50% of total production in 2005. As a result, we believe our revenues, profitability and cash flows will be less sensitive to natural gas prices and more sensitive to oil and condensate prices.

Generally, our 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 three successful wells in six attempts in the second quarter of 2004. Property and equipment additions of $68.1 million in the second quarter of 2004 included leasehold and other acquisition costs of approximately $9.9 million, exploration costs of $39.0 million, development costs of $19.0 million and other property and equipment costs of $0.2 million. We currently plan to drill approximately 12 wells on the shelf and 8 wells in the deep water in the second half of 2004. We expect more than 50% of our 2004 capital expenditure budget to be used for exploration activities, up from 34% in 2003.

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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 a company 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 all future development costs. The DD&A rate increases due to costs incurred without related reserve additions and the timing of reserve recognition, as more reservoir and production information becomes available, compared to the related amortized costs.

The DD&A rate per Mcfe is calculated quarterly and increased 5% to $2.97 in the second quarter of 2004 from $2.82 in the first quarter of 2004. The increase in the DD&A rate was primarily due to the retraction of royalty suspension volumes of 2.4 MMBbls, or 14.3 Bcfe, on Front Runner.

Oil and Gas Reserves

We have achieved reserve growth through exploration activities. We have not acquired reserves through acquisition activities. Ryder Scott Company, L.P. (Ryder Scott) prepares estimates of our proved oil and gas reserves as of June 30 and December 31 each year. As of June 30, 2004, Ryder Scott estimated net proved reserves at approximately 319.0 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 50% of total proved reserves as of June 30, 2004 compared to 10% as of December 31, 2000. Proved undeveloped reserves were approximately 64% of total proved reserves as of June 30, 2004. Reserves associated with Front Runner represented approximately 72% of total proved undeveloped reserves. As each Front Runner well is completed over the next 12 months, the majority of these proved undeveloped reserves will be reclassified as proved developed 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.

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. However, these contracts also limit the benefits we would realize if prices increase. We recorded a net hedging loss of $3.3 million in the second quarter of 2004 compared to a net hedging loss of $9.2 million in the second quarter of 2003. The net hedging loss in the first six months of 2004 was $1.5 million compared to $26.9 million in the same period of 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 ability to access 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 whereas 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 expenses 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.

Oil and Gas 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.

The Minerals Management Service (MMS) allows royalty relief under the Deep Water Royalty Relief Act subject to certain oil and gas price thresholds on eligible leases in the Gulf of Mexico. If the average annual NYMEX oil and gas prices exceed the price thresholds, royalty suspension volumes are retracted in that year. Average natural gas and oil prices have exceeded these thresholds in recent years for certain leases. At or near current levels, average annual NYMEX oil and gas prices in 2004 may exceed these thresholds.

Front Runner area reserves are subject to royalty relief on the first 87.5 million equivalent barrels of oil produced. At the end of each period, reserves are estimated based on oil and gas prices then in effect. Prior to June 30, 2004, our share of gross Front Runner reserves excluded royalty relief volumes for future natural gas production and included royalty relief volumes for future oil production. The MMS has estimated a 2004 oil price threshold of $33.29 per barrel that is applicable to Green Canyon Blocks 338 and 339 and $29.86 per barrel that is applicable to Green Canyon Block 382. Based on the average oil price as of June 30, 2004, we believe the thresholds will be exceeded and the leases will not qualify for royalty relief. As a result, we incurred a downward reserve revision of approximately 2.4 million barrels, or 14.3 Bcfe, in the second quarter of 2004.

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 included in our annual report on Form 10-K.

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Depreciation, Depletion & Amortization

Our 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. We compute 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 June 30, 2004, 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 June 30, 2004, and no additional reserves were assigned to the Front Runner project, the DD&A rate in the second quarter of 2004 would have been $3.06 per Mcfe, or an increase of $0.09 over the actual DD&A rate of $2.97 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 end of the quarter, 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 June 30, 2004, Spinnaker s full cost ceiling, including estimated future net cash flows calculated using commodity prices of $6.45 per Mcf of natural gas and $32.95 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 $194.6 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.

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Leasehold Costs

In June 2001, the 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 and the extractive industries 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 $85.8 million and $72.2 million as of June 30, 2004 and December 31, 2003, 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 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. Spinnaker will continue to classify its oil and gas leasehold costs as tangible oil and gas properties until further guidance is provided.

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. We use 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

As of June 30, 2004, 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. We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. These hedging arrangements take the form of swap contracts or cashless collars and are placed with major financial institutions. We recorded a net hedging loss of $3.3 million and a net hedging loss of $1.5 million in the three and six months ended June 30, 2004, 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 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 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 $0.2 million and $0 in the second quarter of 2004 and 2003, respectively, and $0.2 million and $0 in the first six months of 2004 and 2003, respectively. For further information concerning SFAS 123 see Note 2 of the Notes to Consolidated Financial Statements.

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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 $6.4 million in the first six months of 2004 from affiliates of Baker Hughes. Mr. Michael E. Wiley, a director of Spinnaker, serves as Chairman of the Board and Chief Executive Officer of Baker Hughes. Spinnaker incurred charges of less than $0.1 million in the first six months of 2004 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 less than $0.1 million in the first six months of 2004 from National-Oilwell. Mr. Roger L. Jarvis, Chairman of the Board, Chief Executive Officer and President of Spinnaker, serves as a director of National-Oilwell. These amounts represent less than 1% of Baker Hughes , Cooper Cameron s and National-Oilwell s total revenues in the six months ended June 30, 2004 and only reflect charges directly incurred by us. Our partners may incur charges from these related parties that are not included above.

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.

Oil and Gas Reserves

The following table presents estimated net proved oil and gas reserves and the related present value of future net cash flows of the reserves as of June 30, 2004 as prepared by Ryder Scott. The present value of future net cash flows (before income taxes) discounted at 10% shown in the table are not intended to represent the current market value of the estimated oil and gas reserves we own.

The present value of future net cash flows as of June 30, 2004 was determined by using prices of $6.45 per Mcf of natural gas and $32.95 per barrel of oil as of June 30, 2004.

	Proved Reserves		
	Developed	**Undeveloped**	**Total**
Natural gas (MMcf)	81,157	77,893	159,050
Oil and condensate (MBbls)	5,538	21,115	26,653
Total proved reserves (MMcfe)	114,386	204,583	318,969
Present value of future net cash flows (before income taxes) discounted at 10% (in thousands) (1)	$ 491,693	$ 614,138	$ 1,105,831

(1) Excludes net pre-tax unrealized losses of $6.3 million for the effects of hedging activities using natural gas prices in effect as of June 30, 2004.

The process of estimating oil and gas reserves is complex. Ryder Scott prepares our 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 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. Therefore, estimates of oil and gas reserves are 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 estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control. As of June 30, 2004, approximately 80% of our proved reserves were either undeveloped or non-producing. 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.

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As of June 30, 2004, approximately 64% of our proved reserves were undeveloped and primarily related to Front Runner. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make these expenditures. Although the estimates of our reserves and the costs associated with developing them are prepared in accordance with industry standards, the estimated costs may be inaccurate, development may not occur as scheduled and the results may not be as estimated.

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 Securities and Exchange 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.

Results of Operations

	Three Months Ended June 30,			Six Months Ended June 30,		
	2004	**2003**	**% Change**	**2004**	**2003**	**% Change**
Production:						
Natural gas (MMcf)	10,118	10,206	(1)%	18,421	21,791	(15)%
Oil and condensate (MBbls)	582	343	70%	914	695	32%
Total (MMcfe)	13,611	12,264	11%	23,906	25,963	(8)%
Revenues (in thousands):						
Natural gas	$ 62,157	$ 54,706	14%	$ 108,379	$ 132,194	(18)%
Oil and condensate	21,311	9,909	115%	32,858	21,984	49%
Net hedging income (loss)	(3,285)	(9,167)	64%	(1,546)	(26,910)	94%
Other	(359)	483	(174)%	(76)	334	(123)%
Total	$ 79,824	$ 55,931	43%	$ 139,615	$ 127,602	9%
Average realized sales price per unit:						
Natural gas revenues from production (per Mcf)	$ 6.14	$ 5.36	15%	$ 5.88	$ 6.07	(3)%
Effects of hedging activities (per Mcf)	(0.32)	(0.89)	64%	(0.08)	(1.24)	94%
Average realized price (per Mcf)	$ 5.82	$ 4.47	30%	$ 5.80	$ 4.83	20%
Oil and condensate revenues from production (per Bbl)	$ 36.61	$ 28.89	27%	$ 35.95	$ 31.62	14%
Effects of hedging activities (per Bbl)						
Average realized price (per Bbl)	$ 36.61	$ 28.89	27%	$ 35.95	$ 31.62	14%
Total revenues from production (per Mcfe)	$ 6.13	$ 5.27	16%	$ 5.91	$ 5.94	(1)%
Effects of hedging activities (per Mcfe)	(0.24)	(0.75)	68%	(0.07)	(1.04)	93%
Total average realized price (per Mcfe)	$ 5.89	$ 4.52	30%	$ 5.84	$ 4.90	19%

Expenses:						
Lease operating expenses	$ 6,530	$ 5,208	25%	$ 11,243	$ 10,701	5%
Lease operating expenses (per Mcfe)	$ 0.48	$ 0.42	14%	$ 0.47	$ 0.41	15%
Depreciation, depletion and amortization oil and gas properties	$ 40,404	$ 31,242	29%	$ 69,404	$ 64,077	8%
Depreciation, depletion and amortization oil and gas properties (per Mcfe)	$ 2.97	$ 2.55	17%	$ 2.90	$ 2.47	18%

Three Months Ended June 30, 2004 as Compared to the Three Months Ended June 30, 2003

Revenues and Production

Revenues increased $23.9 million, or 43%, in the second quarter of 2004 compared to the second quarter of 2003. The increase was due to a 16% higher commodity price, 11% higher production and a decrease in net hedging losses and other of $5.0 million.

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Production increased approximately 1.3 Bcfe, or 11%, in the second quarter of 2004 compared to the second quarter of 2003, primarily due to new wells that commenced production subsequent to June 30, 2003, partially offset by normal production declines. Average daily production in the second quarter of 2004 was 150 MMcfe compared to 135 MMcfe in the second quarter of 2003. Natural gas revenues increased $7.5 million, or 14%, due to a 15% higher natural gas price, partially offset by the impact of a decrease in production of 0.1 Bcf, or 1%, in the second quarter of 2004. Excluding the effects of hedging activities, the second quarter 2004 natural gas price was $6.14 per Mcf compared to $5.36 per Mcf in the second quarter of 2003. Oil and condensate revenues increased $11.4 million, or 115%, due to an increase in production of 239 MBbls, or 70%, and a 27% higher price in the second quarter of 2004. The second quarter 2004 oil and condensate price was $36.61 per barrel compared to $28.89 per barrel in the second quarter of 2003.

Lease Operating Expenses

LOE includes 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. LOE increased $1.3 million, or 25%, in the second quarter of 2004 compared to the second quarter of 2003. Of the total increase in LOE, approximately $2.1 million was attributable to operating costs associated with new wells that commenced production subsequent to June 30, 2003, partially offset by a net decrease in LOE of $0.8 million associated with all other producing properties. The LOE rate increased 14% to $0.48 per Mcfe primarily due to higher LOE rates on new wells.

Depreciation, Depletion and Amortization

DD&A increased $9.2 million, or 29%, in the second quarter of 2004 compared to the second quarter of 2003. Of the total increase in DD&A, $5.2 million related to a higher DD&A rate and $4.0 million related to higher production volumes of 1.3 Bcfe. The increase in the DD&A rate was primarily due to costs associated with unsuccessful drilling operations, higher finding costs and the timing of reserve recognition, as more reservoir and production information becomes available, compared to the related amortized costs. Dry hole costs, including associated leasehold costs, were approximately $9.3 million in the second quarter of 2004. Of the total $0.15 per Mcfe increase in the DD&A rate from the first quarter of 2004, $0.12 per Mcfe resulted from the retraction of royalty suspension volumes of 2.4 MMBbls, or 14.3 Bcfe, on Front Runner.

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 $1.2 million, or 41%, in the second quarter of 2004 compared to the second quarter of 2003. The increase was primarily due to higher employment-related costs of $0.5 million associated with an increase in the number of employees since June 30, 2003, catastrophic loss insurance expense of $0.5 million for the period prior to first production related to Front Runner and stock compensation expense of $0.2 million.

Six Months Ended June 30, 2004 as Compared to the Six Months Ended June 30, 2003

Revenues and Production

Revenues increased $12.0 million, or 9%, in the first six months of 2004 compared to the same period of 2003. The increase was primarily due to a decrease in net hedging losses and other of $25.0 million, partially offset by the impact of 8% lower production and a 1% lower commodity price.

Production decreased approximately 2.1 Bcfe, or 8%, in the first six months of 2004 compared to the same period of 2003 primarily 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, partially offset by new wells that commenced production subsequent to June 30, 2003. Average daily production in the first six months of 2004 was 131 MMcfe compared to 143 MMcfe in the same period of 2003. Natural gas revenues decreased $23.8 million, or 18%, due to a decrease in production of 3.4 Bcf, or 15%, and a 3% lower price before the effects of hedging. Excluding the effects of hedging activities, the natural gas price was $5.88 per Mcf in the first six months of 2004 compared to $6.07 per Mcf in the same period of 2003. Oil and condensate revenues increased $10.9 million, or 49%, due to an increase in production of 219 MBbls, or 32%, and a 14% higher price in the first six months of 2004. The oil and condensate price was $35.95 per barrel in the first six months of 2004 compared to $31.62 per barrel in the same period of 2003.

Lease Operating Expenses

Lease operating expenses increased $0.5 million, or 5%, in the first six months of 2004 compared to the same period of 2003. Of the total increase in lease operating expenses, approximately $2.5 million was attributable to operating costs associated with new wells that commenced production subsequent to June 30, 2003, partially offset by a net decrease in LOE of $2.0 million associated with all other producing properties. The LOE rate increased 15% to $0.47 per Mcfe primarily due to lower production in the first six months of 2004 and higher LOE rates on new wells.

Depreciation, Depletion and Amortization

DD&A increased $5.3 million, or 8%, in the first six months of 2004 compared to the same period of 2003. Of the total increase in DD&A, $11.3 million related to a higher DD&A rate, offset in part by $6.0 million related to lower production volumes of 2.1 Bcfe. The increase in the DD&A rate was primarily due to costs associated with unsuccessful drilling operations, higher finding costs and the timing of reserve recognition, as more reservoir and production information becomes available, compared to the related amortized costs. Dry hole costs, including associated leasehold costs, were approximately $32.0 million in the first six months of 2004.

General and Administrative

General and administrative expenses increased $1.7 million, or 28%, in the first six months of 2004 compared to the same period of 2003. The increase was primarily due to higher employment-related costs of approximately $0.8 million associated with an increase in the number of employees since June 30, 2003, catastrophic loss insurance expense of $0.5 million for the period prior to first production related to Front Runner and stock compensation expense of $0.2 million.

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 our financial position, results of operations, cash flows, quantities of oil and gas reserves that may be economically produced and ability to access 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. We have capital expenditure plans for 2004 totaling approximately $270.0 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.

Property and equipment additions in the second quarter of 2004 were $68.1 million. We incurred capital expenditures of approximately $18.1 million in the second quarter of 2004 related to development activities, including $9.5 million associated with the deepwater discovery at Front

Runner. Inception-to-date capital expenditures through June 30, 2004 on the Front Runner project were $142.9 million. As of June 30, 2004, we expect to incur approximately $51.6 million in future development costs related to Front Runner, including approximately $13.1 million in the remainder of 2004 and $38.5 million thereafter. On August 3, 2004, the contractor completed construction of and handed over the Front Runner spar to the Front Runner partners. First production is expected in the fourth quarter of 2004.

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 June 30, 2004, we had borrowings of $93.0 million and were in compliance with the covenants and restrictive provisions under the Revolver. Subsequent to June 30, 2004, we had no additional borrowings; however, we expect to incur additional borrowings under Tranche A of the Revolver in the remainder of 2004.

We have 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. As of June 30, 2004, we had borrowings of $93.0 million outstanding under Tranche A of the Revolver, which is due on December 19, 2006. We had no capital lease or purchase obligations or other contractual long-term liabilities as of June 30, 2004, except for obligations incurred in the ordinary course of business.

Components of Cash Flow

Cash and cash equivalents increased $0.7 million to $16.0 million as of June 30, 2004. The components of the increase in cash and cash equivalents included $102.5 million provided by operating activities, $151.1 million used in investing activities and $49.3 million provided by financing activities.

Operating Activities

Net cash provided by operating activities in the first six months of 2004 decreased 21% to $102.5 million, primarily due to a significant net increase in operating assets and liabilities. 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. We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. However, these contracts may also limit the benefits we would realize if prices increase. See Item 3. Quantitative and Qualitative Disclosures About Market Risk.

As of June 30, 2004, we had negative working capital of $5.5 million. 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. Our cash flow from operations depends on our ability to manage working capital, including accounts receivable, accounts payable and accrued liabilities. The net increase of $23.7 million in accounts receivable was primarily related to increases of $12.4 million in joint interest billings, $8.1 million in oil and gas revenues receivable and $0.9 million in insurance claims receivable compared to December 31, 2003. 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 increased primarily due to a 30% higher commodity price in June 2004 compared to December 2003. The increase in insurance claims receivable related primarily to two new claims in the second quarter of 2004, offset in part by collections on prior claims. Accounts payable and accrued liabilities decreased $6.8 million. Fluctuations in accounts payable and accrued liabilities from period to period occur based primarily on exploratory and development activities in progress and the timing of payments we make to vendors and other operators. We expect to settle asset retirement obligations of approximately $1.1 million in the next twelve months.

Accounts receivable includes insurance claims receivable of $3.7 million. When an event occurs, we assess the incident for insurability and estimate the recovery. All claims are subject to customary underwriter review and assessment. We anticipate that our well control insurance will cover these claims; however, any portion of a claim that is denied by underwriters is transferred to the full cost pool and amortized through DD&A.

Investing Activities

Net cash used in investing activities was $151.1 million as of June 30, 2004 and included oil and gas property cash expenditures of $150.0 million and purchases of other property and equipment of $1.1 million.

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 seven wells in the second quarter of 2004, four of which

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were successful. We drilled 29 wells in 2003, 20 of which were successful. Since inception and through June 30, 2004, we drilled 161 wells, 97 of which were successful, representing a success rate of 60%. Dry hole costs, including associated leasehold costs, were $9.3 million and $32.0 million in the three and six months ended June 30, 2004, respectively.

We have capital expenditure plans for 2004 totaling approximately $270.0 million, primarily for costs related to acquisition, exploration and development activities. 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 June 30, 2004	As of December 31, 2003
Leasehold, delay rentals and seismic data	$ 138,696	$ 119,708
Wells in-progress	10,655	29,459
Other	1,299	2,047
Total	$ 150,650	$ 151,214

Financing Activities

Net cash provided by financing activities of $49.3 million as of June 30, 2004 related to proceeds of $43.0 million from borrowings and $6.4 million from stock option exercises. We paid debt issue costs of approximately $0.1 million in the first six months of 2004 in connection with the Revolver.

On December 19, 2003, Spinnaker revised and renewed the $200.0 million 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 $140.0 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. We have made no borrowings under Tranche B. 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 interest 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:

Incurrence of 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.

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Liens are generally prohibited; however, we may grant a lien in connection with 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 and asset retirement obligations 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 future 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 66 $^{2}/3$% of estimated future production for the next 18 months and 33 $^{1}/3$% 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 June 30, 2004, we had outstanding borrowings of $93.0 million under Tranche A and were in compliance with the covenants and restrictive provisions under the Revolver. Subsequent to June 30, 2004, we had no additional borrowings; however, we expect to incur additional borrowings under Tranche A of the Revolver in the remainder of 2004.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

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. 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. We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. We do 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 financial institutions 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 662/3% 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 June 30, 2004, 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)
Third Quarter 2004	30,000	$ 5.13	$ (2,826)
Fourth Quarter 2004	8,370	4.92	(1,100)
First Quarter 2005	5,000	7.05	144
Total			$ (3,782)

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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 price. As of June 30, 2004, 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)
Third Quarter 2004	20,000	$ 5.48	$ 4.38	$ (1,362)
Fourth Quarter 2004	18,370	6.56	4.73	(1,175)
Total				$ (2,537)

We reported net liabilities of $6.3 million and $2.7 million related to our financial derivative contracts as of June 30, 2004 and December 31, 2003, respectively. Amounts related to hedging activities were as follows (in thousands):

	As of June 30, 2004	As of December 31, 2003
Current assets:		
Hedging assets	$	$ 203
Deferred tax asset related to hedging activities	$ 2,275	$ 972
Current liabilities:		
Hedging liabilities	$ 6,319	$ 2,903
Equity:		
Accumulated other comprehensive loss	$ (4,044)	$ (1,728)

We recognized no ineffective component of the derivatives in the three and six months ended June 30, 2004 and 2003. We recognized a net hedging loss in revenues in the three and six months ended June 30, 2004 and 2003 as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
Net hedging loss	$ (3,285)	$ (9,167)	$ (1,546)	$ (26,910)

Based on future natural gas prices as of June 30, 2004, we would reclassify a net loss of $6.4 million from accumulated other comprehensive loss to earnings in the remainder of 2004 and a gain of $0.1 million from accumulated other comprehensive income to earnings in the first quarter of 2005. The amounts ultimately reclassified into earnings will vary due to changes in the fair value of the open derivative contracts prior to settlement.

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To calculate the potential effect of the derivative contracts on future revenues, we applied NYMEX natural gas forward prices as of June 30, 2004 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 Decrease in Revenues with 10% Decrease in Prices	Estimated Decrease in Revenues with 10% Increase in Prices
Fixed price swap transactions	$ (3,782)	$ (1,294)	$ (6,276)
Collar arrangements	$ (2,537)	$ (1,150)	$ (3,746)

Subsequent to June 30, 2004, 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 $6.41 as of August 4, 2004 was a net liability of approximately $2.0 million for the period September through March 2005. July and August 2004 settlements resulted in a net loss of $2.6 million. The following are our commodity price risk management positions in fixed price natural gas swap contracts and natural gas collar arrangements as of August 5, 2004:

Natural Gas Swap Contracts

Period	Average Daily Volume (MMBtus)	Weighted Average Price (Per MMBtu)
Third Quarter 2004	30,000	$ 5.13
Fourth Quarter 2004	8,370	4.92
First Quarter 2005	5,000	7.05

Natural Gas Collar Arrangements

Period	Average Daily Volume (MMBtus)	Weighted Average Ceiling Price (Per MMBtu)	Weighted Average Floor Price (Per MMBtu)
Third Quarter 2004	20,000	$ 5.48	$ 4.38
Fourth Quarter 2004	18,370	6.56	4.73

Interest Rate Risk

We are 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.

Item 4. Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer performed an evaluation of our disclosure controls and procedures, which have been designed to permit us to effectively identify and timely disclose important information. They concluded that the controls and procedures were effective as of June 30, 2004. During the three months ended June 30, 2004, we made no change in our internal controls over financial reporting that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

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PART II - OTHER INFORMATION

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

The Company held its 2004 Annual Meeting of Stockholders (Annual Meeting) on Wednesday, May 5, 2004. The meeting was held to elect six directors to serve until the 2005 Annual Meeting of Stockholders and to ratify the selection of KPMG LLP as independent auditors of the Company for the fiscal year ending December 31, 2004.

The For column represents affirmative votes by holders of Common Stock represented by either proxy or at the Annual Meeting. Accordingly, because broker non-votes are not counted in determining the total number of votes cast on this proposal, broker non-votes did not affect the outcome of the election of directors. The results of the voting related to the election of the nominees for director were as follows:

Name	For	Withheld
Roger L. Jarvis	29,647,330	410,985
Howard H. Newman	29,053,859	1,004,456
Jeffrey A. Harris	28,761,014	1,297,301
Michael E. McMahon	29,830,400	227,915
Sheldon R. Erikson	27,876,593	2,181,722
Michael E. Wiley	27,884,399	2,173,916

Stockholders voted 29,827,478 shares for and 228,193 shares against the proposal to ratify the selection of KPMG LLP as independent auditors of the Company for the fiscal year ending December 31, 2004, with 2,644 votes abstaining.

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits

See Exhibit Index.

(b) Reports on Form 8-K

A Current Report on Form 8-K dated April 29, 2004 and furnished on April 30, 2004 provided first quarter 2004 earnings and operations information through April 29, 2004 pursuant to Item 12, Results of Operations and Financial Condition.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	SPINNAKER EXPLORATION COMPANY	
Date: August 5, 2004	By:	/s/ ROBERT M. SNELL
		Robert M. Snell Vice President, Chief Financial Officer and Secretary
Date: August 5, 2004	By:	/s/ JEFFREY C. ZARUBA
		Jeffrey C. Zaruba Vice President, Treasurer and Assistant Secretary

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EXHIBIT INDEX

Exhibit Number	Description
12.1	Calculation of Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends
31.1	Certification of Principal Executive Officer of Spinnaker Exploration Company Pursuant to Section 302 of the Sarbanes-Oxley Act
31.2	Certification of Principal Financial Officer of Spinnaker Exploration Company Pursuant to Section 302 of the Sarbanes-Oxley Act
32.1	Certification of Chief Executive Officer of Spinnaker Exploration Company Pursuant to 18 U.S.C. § 1350
32.2	Certification of Chief Financial Officer of Spinnaker Exploration Company Pursuant to 18 U.S.C. § 1350