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, 2003.**

¨ **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 **(State or other jurisdiction of incorporation or organization)**	**76-0560101** **(I.R.S. Employer Identification No.)**
1200 Smith Street, Suite 800	
Houston, Texas **(Address of principal executive offices)**	**77002** **(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 13, 2003 was 33,223,733.

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SPINNAKER EXPLORATION COMPANY

Form 10-Q

For the Three and Six Months Ended June 30, 2003

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SPINNAKER EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share data)

	As of June 30, 2003	As of December 31, 2002
	(Unaudited)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 19,218	$ 32,543
Accounts receivable, net of allowance for doubtful accounts of $3,232 at June 30, 2003 and December 31, 2002, respectively	26,915	37,572
Other	8,280	11,438
Total current assets	54,413	81,553
PROPERTY AND EQUIPMENT:		
Oil and gas, on the basis of full-cost accounting:		
Proved properties	1,032,619	879,840
Unproved properties and properties under development, not being amortized	160,582	141,326
Other	15,218	14,461
	1,208,419	1,035,627
Less Accumulated depreciation, depletion and amortization	(341,427)	(274,773)
Total property and equipment	866,992	760,854
OTHER ASSETS	159	308
Total assets	$ 921,564	$ 842,715
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 28,298	$ 29,453
Accrued liabilities and other	48,910	38,542
Hedging liabilities	19,157	19,917
Asset retirement obligations, current portion	1,262	
Total current liabilities	97,627	87,912
ASSET RETIREMENT OBLIGATIONS	28,855	
DEFERRED INCOME TAXES	75,605	61,826
COMMITMENTS AND CONTINGENCIES		
EQUITY:		
Preferred stock, $0.01 par value; 10,000,000 shares authorized; no shares issued and outstanding at June 30, 2003 and December 31, 2002, respectively		
Common stock, $0.01 par value; 50,000,000 shares authorized; 33,231,981 shares issued and 33,220,137 shares outstanding at June 30, 2003 and 33,184,463 shares issued and 33,171,759 shares outstanding at December 31, 2002	332	332
Additional paid-in capital	596,817	596,087
Retained earnings	134,663	109,337
Less: Treasury stock, at cost, 11,844 shares at June 30, 2003 and 12,704 shares at December 31, 2002	(30)	(32)

Accumulated other comprehensive loss	(12,305)	(12,747)
Total equity	719,477	692,977
Total liabilities and equity	$ 921,564	$ 842,715

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 per share data)

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	**2002**	**2003**	**2002**
REVENUES	$ 55,931	$ 37,164	$ 127,602	$ 69,764
EXPENSES:				
Lease operating expenses	5,208	3,734	10,701	7,143
Depreciation, depletion and amortization natural gas and oil properties	31,242	21,231	64,077	38,608
Depreciation and amortization other	322	210	633	383
Accretion expense	569		1,064	
Gain on settlement of asset retirement obligations	(171)		(171)	
General and administrative	3,001	2,733	6,040	5,411
Total expenses	40,171	27,908	82,344	51,545
INCOME FROM OPERATIONS	15,760	9,256	45,258	18,219
OTHER INCOME (EXPENSE):				
Interest income	62	620	127	664
Interest expense, net	(153)	(155)	(302)	(449)
Total other income (expense)	(91)	465	(175)	215
INCOME BEFORE INCOME TAXES	15,669	9,721	45,083	18,434
Income tax expense	5,641	3,499	16,230	6,636
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	10,028	6,222	28,853	11,798
Cumulative effect of change in accounting principle			(3,527)	
NET INCOME	$ 10,028	$ 6,222	$ 25,326	$ 11,798
BASIC INCOME PER COMMON SHARE:				
Income before cumulative effect of change in accounting principle	$ 0.30	$ 0.19	$ 0.87	$ 0.39
Cumulative effect of change in accounting principle (Note 3)			(0.11)	
NET INCOME PER COMMON SHARE	$ 0.30	$ 0.19	$ 0.76	$ 0.39
DILUTED INCOME PER COMMON SHARE:				
Income before cumulative effect of change in accounting principle	$ 0.30	$ 0.18	$ 0.85	$ 0.38
Cumulative effect of change in accounting principle			(0.10)	
NET INCOME PER COMMON SHARE	$ 0.30	$ 0.18	$ 0.75	$ 0.38

WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:				
Basic	33,207	33,030	33,199	30,200
Diluted	33,859	34,162	33,776	31,330

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, 2003	Six Months Ended June 30, 2002
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 25,326	$ 11,798
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	64,710	38,991
Accretion expense	1,064	
Gain on settlement of asset retirement obligations	(171)	
Deferred income tax expense	15,970	6,936
Cumulative effect of change in accounting principle	3,527	
Other	132	490
Change in operating assets and liabilities:		
Accounts receivable	10,657	(16,345)
Accounts payable and accrued liabilities	5,891	4,379
Other assets	3,034	(4,419)
Net cash provided by operating activities	130,140	41,830
CASH FLOWS FROM INVESTING ACTIVITIES:		
Oil and gas property expenditures	(144,203)	(184,432)
Proceeds from sale of natural gas and oil property and equipment	1,148	
Purchases of other property and equipment	(757)	(3,694)
Net cash used in investing activities	(143,812)	(188,126)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings		37,000
Payments on borrowings		(37,000)
Proceeds from issuance of common stock		227,873
Common stock issuance costs		(469)
Proceeds from exercise of stock options	347	892
Net cash provided by financing activities	347	228,296
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(13,325)	82,000
CASH AND CASH EQUIVALENTS, beginning of year	32,543	14,061
CASH AND CASH EQUIVALENTS, end of period	$ 19,218	$ 96,061
SUPPLEMENTAL CASH FLOW DISCLOSURES:		
Cash paid for interest, net of amounts capitalized	$ 149	$ 315
Cash paid for income taxes, net	$ 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, 2003

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, 2002.

2. Summary of Significant Accounting Policies

Stock-Based Compensation

Statement of Financial Accounting Standards (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 Company s 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 and less than $0.1 million in the three months ended June 30, 2003 and 2002, respectively, and $0 and $0.1 million in the six months ended June 30, 2003 and 2002, 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):

	Three Months Ended June 30,	Six Months Ended June 30,

	2003	2002	2003	2002
Net income, as reported	$ 10,028	$ 6,222	$ 25,326	$ 11,798
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects		19		85
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(3,021)	(1,930)	(4,867)	(4,815)
Pro forma net income	$ 7,007	$ 4,311	$ 20,459	$ 7,068
Net income per common share:				
Basic, as reported	$ 0.30	$ 0.19	$ 0.76	$ 0.39
Basic, pro forma	$ 0.21	$ 0.13	$ 0.62	$ 0.23
Diluted, as reported	$ 0.30	$ 0.18	$ 0.75	$ 0.38
Diluted, pro forma	$ 0.20	$ 0.12	$ 0.60	$ 0.22

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Leasehold Costs

SFAS No. 141, Business Combinations and SFAS No. 142, Goodwill and Intangible Assets, became effective on July 1, 2001 and January 1, 2002, respectively. The Company understands that the Securities and Exchange Commission (SEC) has raised the issue and the Financial Accounting Standards Board (FASB) is evaluating whether SFAS 141 and SFAS 142 require the cash costs of oil and gas leasehold interests or other contractual arrangements to be classified as intangible assets. If such costs were deemed to be intangible assets, the costs for both undeveloped and developed leaseholds would be classified separate from oil and gas properties as intangible assets on Spinnaker s consolidated balance sheets. Historically Spinnaker, and to the Company s knowledge, almost all other oil and gas companies have included these oil and gas leasehold costs as part of oil and gas properties after SFAS 141 and SFAS 142 became effective.

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.

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, net of taxes of $2.0 million.

The reconciliation of the beginning and ending asset retirement obligations as of June 30, 2003 is as follows (in thousands):

	Three Months Ended June 30, 2003	Six Months Ended June 30, 2003
Asset retirement obligations, beginning of period	$ 27,275	$
Liabilities upon adoption of SFAS No. 143 on January 1, 2003		25,954
Liabilities incurred	5,019	5,845
Liabilities settled	(2,638)	(2,638)
Accretion expense	569	1,064
Revisions in estimated cash flows	(108)	(108)
Asset retirement obligations, as of June 30, 2003	$ 30,117	$ 30,117

The following table summarizes the pro forma net income and earnings per share for the three and six months ended June 30, 2002 and for the years ended December 31, 2002, 2001 and 2000 as if SFAS No. 143 had been adopted on January 1, 2000 (in thousands, except per share amounts):

	Three Months Ended June 30, 2002	Six Months Ended June 30, 2002	Year Ended December 31, 2002	2001	2000
Net income:					
As reported	$ 6,222	$ 11,798	$ 31,579	$ 66,226	$ 38,566
Pro forma	5,890	11,161	30,419	65,084	37,341
Net income per share, as reported:					
Basic	$ 0.19	$ 0.39	$ 1.00	$ 2.45	$ 1.70
Diluted	0.18	0.38	0.97	2.34	1.61
Net income per share, pro forma:					
Basic	$ 0.18	$ 0.37	$ 0.96	$ 2.40	$ 1.65
Diluted	0.17	0.36	0.93	2.29	1.56

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The following table summarizes pro forma asset retirement obligations as of June 30, 2002 and December 31, 2002, 2001 and 2000 as if SFAS No. 143 had been adopted on January 1, 2000 (in thousands):

	As of June 30,	As of December 31,		
	2002	2002	2001	2000
Asset retirement obligations, pro forma	$ 24,591	$ 25,949	$ 22,020	$ 15,926

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,	
	2003	2002	2003	2002
Numerator:				
Net income	$ 10,028	$ 6,222	$ 25,326	$ 11,798
Denominator:				
Basic weighted average number of shares	33,207	33,030	33,199	30,200
Dilutive securities:				
Stock options	652	1,132	577	1,130
Diluted adjusted weighted average number of shares and assumed conversions	33,859	34,162	33,776	31,330
Basic income per common share:				
Income before cumulative effect of change in accounting principle	$ 0.30	$ 0.19	$ 0.87	$ 0.39
Cumulative effect of change in accounting principle			(0.11)	
Net income per common share	$ 0.30	$ 0.19	$ 0.76	$ 0.39
Diluted income per common share:				
Income before cumulative effect of change in accounting principle	$ 0.30	$ 0.18	$ 0.85	$ 0.38
Cumulative effect of change in accounting principle			(0.10)	
Net income per common share	$ 0.30	$ 0.18	$ 0.75	$ 0.38

5. Credit Facility

On December 28, 2001, the Company replaced its $75.0 million credit facility with an unsecured $200.0 million credit facility (Credit Facility) with a group of seven banks. The borrowing base of the three-year Credit Facility is re-determined on a semi-annual basis each year. The banks and Spinnaker also have the option to request one additional re-determination each year. The banks determine the borrowing base in their sole discretion and in their usual and customary manner. The amount of the borrowing base is a function of the banks view of the Company s reserve profile as well as commodity prices. The current borrowing base is $100.0 million. The Company has the option to elect to use a base interest rate as described below or the LIBOR rate plus, for each such rate, a spread based on the percentage of the borrowing base used at that time. The base interest rate under the Credit Facility is a fluctuating rate of interest equal to the higher of either (i) 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 0.3% to 0.5%, depending on the borrowing base usage. The Credit Facility contains various covenants and restrictive provisions. At June 30, 2003, the Company had no outstanding borrowings and was in compliance with the covenants and restrictive provisions under the Credit Facility.

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6. Derivatives and Hedging

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, 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)
Third Quarter 2003	53,370	$ 3.69	$ (8,259)
Fourth Quarter 2003	50,000	3.63	(9,257)
Total			$ (17,516)

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 price and the fixed ceiling price. As of June 30, 2003, Spinnaker s commodity price risk management positions in natural gas collar arrangements and related fair values were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Floor Price (Per MMBtu)	Weighted Average Ceiling Price (Per MMBtu)	Fair Value (in thousands)
Third Quarter 2003	15,000	$ 3.25	$ 5.21	$ (491)
Fourth Quarter 2003	15,000	3.25	5.21	(1,150)
Total				$ (1,641)

The Company reported net liabilities of $19.2 million and $19.9 million related to its financial derivative contracts as of June 30, 2003 and December 31, 2002, respectively. Amounts related to hedging activities were as follows (in thousands):

	As of June 30, 2003	As of December 31, 2002
Current assets:		
Deferred tax asset related to hedging activities	$ 6,897	$ 7,170
Current liabilities:		
Hedging liabilities	$ 19,157	$ 19,917
Equity:		
Accumulated other comprehensive loss	$ (12,305)	$ (12,747)

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The Company recognized net hedging gains (losses) and the ineffective component of the derivatives in revenues in the three and six months ended June 30, 2003 and 2002 as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Net hedging income (loss)	$ (9,167)	$ (1,773)	$ (26,910)	$ 6,485
Ineffective component of the derivatives	$ (45)	$ (62)	$ (45)	$ 78

Based on future natural gas prices as of June 30, 2003, the Company would reclassify a net loss of $12.3 million from accumulated other comprehensive income (loss) to earnings within the next six months. 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 (loss) (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Net income	$ 10,028	$ 6,222	$ 25,326	$ 11,798
Other comprehensive income (loss), net of tax:				
Net change in fair value of derivative financial instruments	(3,102)	382	(16,780)	(12,908)
Financial derivative settlements reclassified to income	5,867	1,017	17,222	(4,150)
Comprehensive income (loss)	$ 12,793	$ 7,621	$ 25,768	$ (5,260)

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Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

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 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 fu events include the following matters:

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

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

- the risks associated with exploration;
- delays in anticipated start-up dates;
- the ability to find, acquire, market, develop and produce new properties;
- natural gas and oil price volatility;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;
- 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 natural gas and oil 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, 2002.

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Critical Accounting Policies

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities 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 natural gas and oil properties. Natural gas and oil reserve estimates, which are the basis for unit-of-production DD&A and the full cost ceiling test, are inherently imprecise and are expected to change as future information becomes available. 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. The Company s critical accounting policies are as follows:

Full Cost Method of Accounting

The Company uses the full cost method of accounting for its investments in natural gas and oil properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of exploring for and developing natural gas and oil 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 and costs of completions, platforms, facilities and pipelines. Costs associated with production and general corporate activities are expensed in the period incurred. Sales of natural gas and oil properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of natural gas and oil. 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.

DD&A

The Company computes the provision for DD&A of natural gas and oil properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the amortization base until the properties associated with these costs are evaluated. In addition to costs associated with evaluated properties, the amortization base includes estimated future development costs and estimated salvage values associated with asset retirement costs.

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, 2003, the Company excluded from the amortization base estimated future expenditures of $29.9 million associated with common development costs for its deepwater discovery on Green Canyon Blocks 338/339 (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 $29.9 million had been included in the amortization base as of June 30, 2003, and no additional reserves were assigned to the Front Runner project, the DD&A rate as of June 30, 2003 would have been $2.64 per Mcfe, or an increase of $0.09 over the actual DD&A rate of $2.55 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 natural gas and oil reserves used in the full cost ceiling calculation, as discussed below.

Full Cost Ceiling

Capitalized costs of natural gas and oil properties, net of accumulated DD&A, asset retirement obligations and related deferred taxes, are limited to the estimated future net cash flows from proved natural gas and oil reserves, including the effects of hedging activities in place as of June 30, 2003, discounted at 10%, plus the lower of cost or fair value of unproved

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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, 2003, the Company s full cost ceiling, including estimated future net cash flows calculated using commodity prices of $5.62 per Mcf of natural gas and $28.74 per barrel of oil and condensate, exceeded capitalized costs of natural gas and oil properties, net of accumulated DD&A, asset retirement obligations and related deferred taxes, by approximately $148.7 million. Considering the volatility of natural gas and oil prices, it is probable that the Company s estimate of discounted future net cash flows from proved natural gas and oil reserves will change in the near term. If natural gas or oil prices decline, even if for only a short period of time, or if the Company has downward revisions to its estimated proved reserves, it is possible that write-downs of natural gas and oil properties could occur in the future.

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 $1.7 million and $1.3 million in the three months ended June 30, 2003 and 2002, respectively, and $3.4 million and $2.8 million in the six months ended June 30, 2003 and 2002, respectively.

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.

Leasehold Costs

SFAS No. 141, Business Combinations and SFAS No. 142, Goodwill and Intangible Assets, became effective on July 1, 2001 and January 1, 2002, respectively. The Company understands that the SEC has raised the issue and the FASB is evaluating whether SFAS 141 and SFAS 142 require the cash costs of oil and gas leasehold interests or other contractual arrangements to be classified as intangible assets. If such costs were deemed to be intangible assets, the costs for both undeveloped and developed leaseholds would be classified separate from oil and gas properties as intangible assets on Spinnaker s consolidated balance sheets. Historically Spinnaker, and to the Company s knowledge, almost all other oil and gas companies have included these oil and gas leasehold costs as part of oil and gas properties after SFAS 141 and SFAS 142 became effective.

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.

Asset Retirement Obligations

The Company recognizes 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 at which that liability could be settled in a current transaction between willing parties. The Company 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.

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Natural Gas and Oil Reserves

The following table presents estimated net proved natural gas and oil reserves and the related net present value of the reserves at June 30, 2003 as prepared by Ryder Scott Company, L.P. The present value of future net cash flows (before income taxes) discounted at 10% shown in the table is not intended to represent the current market value of the estimated natural gas and oil reserves Spinnaker owns.

The present value of future net cash flows as of June 30, 2003 was determined by using prices of $5.62 per Mcf of natural gas and $28.74 per barrel of oil.

	Proved Reserves		
	Developed	**Undeveloped**	**Total**
Natural gas (MMcf)	69,973	67,916	137,889
Oil and condensate (MBbls)	5,258	24,331	29,589
Total proved reserves (MMcfe)	101,522	213,899	315,421
Present value of future net cash flows (before income taxes) discounted at 10% (in thousands) (1)	$ 375,559	$ 525,941	$ 901,500

(1) Excludes pre-tax unrealized losses of $19.2 million for the effects of hedging activities using natural gas and oil prices in effect at June 30, 2003.

The process of estimating natural gas and oil reserves is complex. It requires various assumptions, including natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The Company must project production rates and timing of development expenditures. The Company analyzes available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. Therefore, estimates of natural gas and oil reserves are inherently imprecise.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, the Company may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond the Company s control. At June 30, 2003, approximately 81% of the Company s 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.

At June 30, 2003, approximately 68% of the Company s proved reserves were undeveloped, and Front Runner represented more than 60% of total proved undeveloped reserves. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. The reserve data assumes that the Company will make these expenditures. Although the Company estimates its reserves and the costs associated with developing them in accordance with industry standards, the estimated costs may be inaccurate, development may not occur as scheduled and results may not be as estimated.

Other Property and Equipment

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 $0.5 million and $0.3 million in the three months ended June 30, 2003 and 2002, respectively, and $1.0 million and $0.5 million in six months ended June 30, 2003 and 2002, 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.

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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 and less than $0.1 million in the three months ended June 30, 2003 and 2002, respectively, and $0 and $0.1 million in the six months ended June 30, 2003 and 2002, respectively.

Related Parties

The Company purchases oilfield goods, equipment and services from Baker Hughes Incorporated (Baker Hughes), Cooper Cameron Corporation (Cooper Cameron) and other oilfield services companies in the ordinary course of business. The Company incurred charges of approximately $3.0 million in the first six months of 2003 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. The Company incurred charges of less than $0.1 million in first six months of 2003 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 believes that these transactions are at arm s-length and the charges it pays for such goods, equipment and services are competitive with the charges and fees of other companies providing oilfield goods, equipment and services to the oil and gas exploration and production industry. Both of these companies are leaders in their respective segments of the oilfield services sector. The Company could be at a disadvantage if it were to discontinue using either company as vendors.

Overview

Financial and operating results for the three and six months ended June 30, 2003 compared to the same periods in 2002 included:

Three Months Ended June 30, 2003 as Compared to the Three Months Ended June 30, 2002

- Production of 12.3 billion cubic feet gas equivalent (Bcfe), up 16%.
- Revenues of $55.9 million, up 50%.
- Income from operations of $15.8 million, up 70%.
- Net income of $10.0 million, up 61%.
- Net cash provided by operating activities before changes in operating assets and liabilities of $47.6 million, up 52%.

Six Months Ended June 30, 2003 as Compared to the Six Months Ended June 30, 2002

- Production of 26.0 billion cubic feet gas equivalent (Bcfe), up 27%.
- Revenues of $127.6 million, up 83%.
- Income from operations of $45.3 million, up 148%.
- Net income of $25.3 million, up 115%.
- Net cash provided by operating activities before changes in operating assets and liabilities of $110.6 million, up 90%.

Net cash provided by operating activities before changes in operating assets and liabilities is presented because of its acceptance as an indicator of the ability of an oil and gas exploration and production company to internally fund exploration and development activities. This measure should not be considered as an alternative to net cash provided by operating activities as defined by generally accepted accounting principles. A reconciliation of net cash provided by operating activities before changes in operating assets and liabilities to net cash provided by operating activities is shown below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	**2002**	**2003**	**2002**
Net cash provided by operating activities	$ 80,618	$ 9,833	$ 130,140	$ 41,830
Change in operating assets and liabilities	(33,068)	21,520	(19,582)	16,385
Net cash provided by operating activities before changes in operating assets and liabilities	$ 47,550	$ 31,353	$ 110,558	$ 58,215

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Results of Operations

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	**2002**	**2003**	**2002**
Production:				
Natural gas (MMcf)	10,206	9,096	21,791	18,441
Oil and condensate (MBbls)	343	250	695	323
Total (MMcfe)	12,264	10,592	25,963	20,377
Revenues (in thousands):				
Natural gas	$ 54,706	$ 32,431	$ 132,194	$ 55,451
Oil and condensate	9,909	6,502	21,984	7,869
Net hedging income (loss)	(9,167)	(1,773)	(26,910)	6,485
Other	483	4	334	(41)
Total	$ 55,931	$ 37,164	$ 127,602	$ 69,764
Average sales price per unit:				
Natural gas revenues from production (per Mcf)	$ 5.36	$ 3.57	$ 6.07	$ 3.01
Effects of hedging activities (per Mcf)	(0.89)	(0.20)	(1.24)	0.35
Average price (per Mcf)	$ 4.47	$ 3.37	$ 4.83	$ 3.36
Oil and condensate revenues from production (per Bbl)	$ 28.89	$ 26.09	$ 31.62	$ 24.38
Effects of hedging activities (per Bbl)				
Average price (per Bbl)	$ 28.89	$ 26.09	$ 31.62	$ 24.38
Total revenues from production (per Mcfe)	$ 5.27	$ 3.68	$ 5.94	$ 3.11
Effects of hedging activities (per Mcfe)	(0.75)	(0.17)	(1.04)	0.32
Total average price (per Mcfe)	$ 4.52	$ 3.51	$ 4.90	$ 3.43
Expenses (per Mcfe):				
Lease operating expenses	$ 0.42	$ 0.35	$ 0.41	$ 0.35
Depreciation, depletion and amortization natural gas and oil properties	$ 2.55	$ 2.00	$ 2.47	$ 1.89
Income from operations (in thousands)	$ 15,760	$ 9,256	$ 45,258	$ 18,219

Three Months Ended June 30, 2003 as Compared to the Three Months Ended June 30, 2002

Revenues, including the effects of hedging activities, increased $18.8 million in the second quarter of 2003 compared to the second quarter of 2002. The increase in revenues was primarily due to increased production and higher natural gas and oil prices in the second quarter of 2003. Excluding the effects of hedging activities, natural gas revenues increased $22.3 million and oil and condensate revenues increased $3.4 million. Revenues from natural gas hedging activities and other were negatively impacted by $6.9 million in the second quarter of 2003 compared to the same period of 2002.

Production increased approximately 1.7 Bcfe in the second quarter of 2003 compared to the second quarter of 2002. Average daily production in the second quarter of 2003 was 135 million cubic feet gas equivalent (MMcfe) compared to 116 MMcfe in the same period of 2002. Natural gas revenues increased $22.3 million due to increased production of 1.1 Bcfe and higher prices in the second quarter of 2003. Excluding the effects of hedging activities, the second quarter 2003 average natural gas price was $5.36 per Mcf compared to $3.57 per Mcf in the second quarter of 2002. Oil and condensate revenues increased $3.4 million due to increased production of 93 thousand barrels (MBbls) and higher prices in the second quarter of 2003. The second quarter 2003 average oil and condensate price was $28.89 per barrel compared to $26.09 per barrel in the same period of 2002.

Lease operating expenses increased $1.5 million in the second quarter of 2003 compared to the second quarter of 2002. Of the total increase in lease operating expenses, approximately $1.3 million was primarily attributable to operating costs associated with new wells on existing producing blocks and wells that produced less than three months through June 30, 2002 compared to three months of production through June 30, 2003 and $0.2 million was related to activity on blocks that commenced production subsequent to June 30, 2002. The overall increase in the lease operating expense rate per Mcfe in the second quarter of 2003 compared to the same period of 2002 was primarily due to higher operating expenses associated with new wells and the addition of compression facilities at several locations. Additionally, the Company s lease operating expense rate per Mcfe will increase in the third quarter of 2003 as a result of an estimated $2.5 million workover on a deepwater property.

DD&A increased $10.1 million in the second quarter of 2003 compared to the second quarter of 2002. Of the total increase in DD&A, $4.2 million related to higher production volumes of 1.7 Bcfe and $5.8 million related to an increase in the DD&A rate per Mcfe in the second quarter of 2003 compared to the same period of 2002. The increase in the DD&A rate was primarily due to unsuccessful wells and higher finding costs associated with discoveries since June 30, 2002. Other depreciation and amortization increased $0.1 million as a result of additions to other property and equipment.

General and administrative expenses increased $0.3 million in the second quarter of 2003 compared to the second quarter of 2002. The increase in general and administrative expenses was primarily due to higher employment-related costs associated with an increase in the number of employees during 2002 and 2003.

Interest income decreased $0.6 million in the second quarter of 2003 compared to the second quarter of 2002 primarily due to lower average cash investment balances and lower interest rates in the second quarter of 2003. Interest expense decreased less than $0.1 million in the second quarter of 2003 compared to the second quarter of 2002.

Income tax expense increased $2.1 million in the second quarter of 2003 compared to the second quarter of 2002 due to higher earnings in the second quarter of 2003. Income taxes were accrued at a 36% effective tax rate in the second quarter of 2003 and 2002.

The Company recognized net income of $10.0 million, or $0.30 per basic and diluted share, in the second quarter of 2003 compared to net income of $6.2 million, or $0.19 per basic share and $0.18 per diluted share, in the second quarter of 2002.

Six Months Ended June 30, 2003 as Compared to the Six Months Ended June 30, 2002

Revenues, including the effects of hedging activities, increased $57.8 million in the first six months of 2003 compared to the first six months of 2002. The increase in revenues was primarily due to increased production and higher natural gas and oil prices in the first six months of 2003. Excluding the effects of hedging activities, natural gas revenues increased $76.7 million and oil and condensate revenues increased $14.1 million. Revenues from natural gas hedging activities and other were negatively impacted by $33.0 million in the first six months of 2003 compared to the same period of 2002.

Production increased approximately 5.6 Bcfe in the first six months of 2003 compared to the first six months of 2002. Average daily production in the first six months of 2003 was 143 MMcfe compared to 113 MMcfe in the same period of 2002. Natural gas revenues increased $76.7 million due to increased production of 3.4 Bcfe and higher prices in the first six months of 2003. Excluding the effects of hedging activities, the average natural gas price was $6.07 per Mcf in the first six months of 2003 compared to $3.01 per Mcf in the same period of 2002. Oil and condensate revenues increased $14.1 million due to increased production of 372 MBbls and higher prices in the first six months of 2003. The average oil and condensate price was $31.62 per barrel in the first six months of 2003 compared to $24.38 per barrel in the same period of 2002.

Lease operating expenses increased $3.6 million in the first six months of 2003 compared to the first six months of 2002. Of the total increase in lease operating expenses, approximately $3.9 million was primarily attributable to operating costs associated with new wells on existing producing blocks and wells that produced less than six months through June 30, 2002 compared to six months of production through June 30, 2003 and $0.4 million was related to activity on blocks that commenced production subsequent to June 30, 2002. Workover expenses decreased $0.7 million in the first six months of 2003 compared to the same period of 2002. The overall increase in the lease operating expense rate per Mcfe in the first six months of 2003 compared to the same period of 2002 was primarily due to higher operating expenses associated with new wells and the addition of compression facilities at several locations. Additionally, the Company s lease operating expense rate per Mcfe will increase in the third quarter of 2003 as a result of an estimated $2.5 million workover on a deepwater property.

DD&A increased $25.7 million in the first six months of 2003 compared to the first six months of 2002. Of the total increase in DD&A, $13.8 million related to higher production volumes of 5.6 Bcfe and $11.7 million related to an increase in

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the DD&A rate per Mcfe in the first six months of 2003 compared to the same period in 2002. The increase in the DD&A rate was primarily due to unsuccessful wells and higher finding costs associated with discoveries since June 30, 2002. Other depreciation and amortization increased $0.2 million as a result of additions to other property and equipment.

General and administrative expenses increased $0.6 million in the first six months of 2003 compared to the first six months of 2002. The increase in general and administrative expenses was primarily due to higher employment-related costs associated with an increase in the number of employees during 2002 and 2003.

Interest income decreased $0.5 million in the first six months of 2003 compared to the first six months of 2002 primarily due to lower average cash investment balances and lower interest rates in the first six months of 2003. Interest expense decreased $0.1 million in the first six months of 2003 compared to the first six months of 2002 primarily due to interest associated with borrowings of $37.0 million in the first quarter of 2002.

Income tax expense increased $9.6 million in the first six months of 2003 compared to the first six months of 2002 due to higher earnings in the first six months of 2003. Income taxes were accrued at a 36% effective tax rate in the first six months of 2003 and 2002.

The Company recognized net income of $25.3 million, or $0.76 per basic share and $0.75 per diluted share, in the first six months of 2003 compared to net income of $11.8 million, or $0.39 per basic share and $0.38 per diluted share, in the first six months of 2002.

Liquidity and Capital Resources

The Company has experienced and expects to continue to experience substantial capital requirements, primarily due to its active exploration and development programs in the Gulf of Mexico. Spinnaker has capital expenditure plans for 2003 totaling approximately $275 million. Additions to property and equipment of $172.8 million in the first six months of 2003 included asset retirement costs of $27.1 million. Spinnaker has participated in a significant deepwater oil discovery, Front Runner, with a 25% non-operator working interest. Spinnaker has incurred inception-to-date capital expenditures associated with Front Runner of $109.2 million. As of June 30, 2003, the Company expects to incur approximately $58.9 million in future development costs related to Front Runner, including approximately $16.0 million in the remainder of 2003, $20.0 million in 2004 and $22.9 million thereafter.

Natural gas and oil prices have a significant impact on the Company s cash flows available for capital expenditures and its ability to borrow and raise additional capital. The amount the Company can borrow under its Credit Facility is subject to periodic re-determination based in part on changing expectations of future prices. Lower prices may also reduce the amount of natural gas and oil that the Company can economically produce. Lower prices and/or lower production may decrease revenues, cash flows and the borrowing base under the Credit Facility, thus reducing the amount of financial resources available to meet the Company s capital requirements. The Company believes that working capital, cash flows from operations, proceeds from available borrowings under its Credit Facility and Front Runner spar production facility financing opportunities will be sufficient to meet its 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 programs. In the event additional capital resources are unavailable, the Company may curtail its drilling, development and other activities or be forced to sell some of its assets on an untimely or unfavorable basis. Subsequent to June 30, 2003, the Company borrowed $18.0 million and expects to incur additional borrowings under the Credit Facility in the second half of 2003 and first half of 2004. The Company experienced negative working capital as of June 30, 2003. However, the Company is in compliance with the covenants and restrictive provisions of the Credit Facility.

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.

Cash and cash equivalents decreased $13.3 million to $19.2 million as of June 30, 2003. The components of the decrease in cash and cash equivalents included $130.1 million provided by operating activities, $143.8 million used in investing activities and $0.4 million provided by financing activities.

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Operating Activities

Net cash provided by operating activities in the first six months of 2003 increased 211% to $130.1 million primarily due to increased production and higher commodity prices. Cash flow from operations is dependent upon the Company s ability to increase production through its exploration and development programs and the prices of natural gas and oil. The Company has made significant investments to expand its operations in the Gulf of Mexico.

The Company sells its natural gas and oil production under fixed or floating market price contracts. Spinnaker enters into hedging arrangements from time to time to reduce its exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. However, these contracts also limit the benefits the Company would realize if prices increase. See Item 3. Quantitative and Qualitative Disclosures About Market Risk.

The Company s cash flow from operations also depends on its ability to manage working capital, including accounts receivable, accounts payable and accrued liabilities. The net decrease of $10.7 million in accounts receivable was primarily related to a decrease of $7.4 million in joint interest billings and other as a result of Spinnaker s higher working interests in projects in the second quarter of 2003 compared to the end of 2002 and a decrease of $2.7 million in oil and gas revenue receivable due to decreased production and lower natural gas and oil prices in June 2003 compared to December 2002. The net increase of $9.2 million in accounts payable and accrued liabilities was primarily due to increased drilling and development activities as of June 30, 2003 compared to December 31, 2002.

Investing Activities

Net cash used in investing activities was $143.8 million in the first six months of 2003 and included oil and gas property capital expenditures of $144.2 million and purchases of other property and equipment of $0.7 million. The Company received proceeds of $1.1 million from the sale of natural gas and oil property and equipment in the first quarter of 2003.

As part of its strategy, the Company explores for natural gas and oil at deeper drilling depths and in the deep waters of the Gulf of Mexico, where operations are more difficult and costly than at shallower drilling depths and in shallower waters. Along with higher risks and costs associated with these areas, greater opportunity exists for reserve additions. The Company has experienced and will continue to experience significantly higher drilling costs for its deep shelf and deepwater projects relative to the drilling costs on shallower depth shelf projects in the Gulf of Mexico. The Company drilled 16 wells in the first six months of 2003, 14 of which were successful. The Company drilled 26 wells in 2002, 14 of which were successful. Since inception and through June 30, 2003, the Company drilled 136 wells, 84 of which were successful, representing a success rate of 62%. Dry hole costs, including associated leasehold costs, were $7.8 million in the first six months of 2003.

The Company has capital expenditure plans for 2003 totaling approximately $275 million, primarily for costs related to exploration and development programs. The Company settled abandonment costs of $2.6 million in the first six months of 2003 and does not anticipate any other significant abandonment or dismantlement expenditures in the remainder of 2003. Actual levels of capital expenditures may vary due to many factors, including drilling results, natural gas and oil prices, the availability of capital, industry conditions, acquisitions, decisions of operators and other prospect owners and the prices of drilling rig dayrates and other oilfield goods and services. 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, 2003	As of December 31, 2002
Leasehold, delay rentals and seismic data	$ 123,061	$ 122,409
Wells in-progress	15,166	17,639
Wells pending determination	21,098	
Other	1,257	1,278
Total	$ 160,582	$ 141,326

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Financing Activities

Net cash provided by financing activities of $0.4 million in the first six months of 2003 related to proceeds from stock option exercises.

On December 28, 2001, the Company replaced its $75.0 million credit facility with an unsecured $200.0 million Credit Facility with a group of seven banks. The borrowing base of the three-year Credit Facility is re-determined on a semi-annual basis each year. The banks and Spinnaker also have the option to request one additional re-determination each year. The banks determine the borrowing base in their sole discretion and in their usual and customary manner. The amount of the borrowing base is a function of the banks view of the Company s reserve profile as well as commodity prices. The current borrowing base is $100.0 million. The Company has the option to elect to use a base interest rate as described below or the LIBOR rate plus, for each such rate, a spread based on the percentage of the borrowing base used at that time. The base interest rate under the Credit Facility is a fluctuating rate of interest equal to the higher of either (i) 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 0.3% to 0.5%, depending on the borrowing base usage.

The Credit Facility contains various covenants and restrictive provisions that are disclosed in the Company s annual report on Form 10-K for the year ended December 31, 2002.

At June 30, 2003, the Company had no outstanding borrowings and was in compliance with the covenants and restrictive provisions under the Credit Facility. Subsequent to June 30, 2003, the Company borrowed $18.0 million and expects to incur additional borrowings under the Credit Facility in the second half of 2003 and first half of 2004. The Company expects to be in compliance with the covenants and restrictive provisions for the next twelve months.

Contractual Obligations

The Company leases administrative offices, office equipment and oil and gas equipment under non-cancelable operating leases. The Company had no long-term debt, capital lease or purchase obligations or other contractual long-term liabilities as of June 30, 2003, except for obligations incurred in the ordinary course of business.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

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

Commodity Price Risk

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

The Company enters into 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

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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, 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)
Third Quarter 2003	53,370	$ 3.69	$ (8,259)
Fourth Quarter 2003	50,000	3.63	(9,257)
Total			$ (17,516)

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 price and the fixed ceiling price. As of June 30, 2003, Spinnaker s commodity price risk management positions in natural gas collar arrangements and related fair values were as follows:

Period	Average Daily Volume (MMBtus)	Weighted Average Floor Price (Per MMBtu)	Weighted Average Ceiling Price (Per MMBtu)	Fair Value (in thousands)
Third Quarter 2003	15,000	$ 3.25	$ 5.21	$ (491)
Fourth Quarter 2003	15,000	3.25	5.21	(1,150)
Total				$ (1,641)

The Company reported net liabilities of $19.2 million and $19.9 million related to its financial derivative contracts as of June 30, 2003 and December 31, 2002, respectively. Amounts related to hedging activities were as follows (in thousands):

	As of June 30, 2003	As of December 31, 2002
Current assets:		
Deferred tax asset related to hedging activities	$ 6,897	$ 7,170
Current liabilities:		
Hedging liabilities	$ 19,157	$ 19,917

Equity:		
Accumulated other comprehensive loss	$ (12,305)	$ (12,747)

Based on future natural gas prices as of June 30, 2003, the Company would reclassify a net loss of $12.3 million from accumulated other comprehensive income (loss) to earnings within the next six months. The amounts ultimately reclassified into earnings will vary due to changes in the fair value of the open derivative contracts prior to settlement.

The Company recognized net hedging gains (losses) and the ineffective component of the derivatives in revenues in the three and six months ended June 30, 2003 and 2002 as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	**2002**	**2003**	**2002**
Net hedging income (loss)	$ (9,167)	$ (1,773)	$ (26,910)	$ 6,485
Ineffective component of the derivatives	$ (45)	$ (62)	$ (45)	$ 78

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To calculate the potential effect of the derivative contracts on future revenues, the Company applied NYMEX natural gas forward prices as of June 30, 2003 to the quantity of the Company s 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	$ (17,516)	$ (13,306)	$ (21,818)
Collar arrangements	$ (1,641)	$ (897)	$ (2,494)

As of August 12, 2003, the fair value of Spinnaker s current commodity price risk management positions in fixed price natural gas swap contracts and natural gas collar arrangements was a net liability of approximately $15.7 million, including settlements in July and August resulting in a net loss of $4.4 million and using natural gas forward prices as of August 12, 2003.

Item 4. Controls and Procedures

(a) *Evaluation of disclosure controls and procedures.* Within 90 days before the filing of this quarterly report on Form 10-Q, the Company s principal executive officer and principal financial officer evaluated the effectiveness of the Company s disclosure controls and procedures. Based on the evaluation, the Company s principal executive officer and principal financial officer believe that:

the Company s disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company in the reports it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms; and

the Company s disclosure controls and procedures were effective to ensure that material information was accumulated and communicated to the Company s management, including the Company s principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

(b) *Changes in internal controls.* On June 27, 2003, management became aware of possible self-dealing transactions by certain consultants to the Company. Spinnaker s Audit Committee engaged independent legal counsel to initiate an investigation. The investigation found that self-dealing by these consultants was involved in certain purchases of used platforms and related facilities for an aggregate of less than $4.0 million. Based on an analysis of the transactions by an independent engineering firm, the independent legal counsel and the Audit Committee concluded that the Company paid fair value for the used platforms and related facilities, and no adjustments to the Company s historical consolidated financial statements are required as a result of this matter. The Company has terminated its consulting relationships with the consultants who were implicated in the independent investigation. The Company believes that these events do not demonstrate a significant deficiency or material weakness in its internal controls. The Company has nonetheless made changes to its procedures for acquiring used equipment and to its forms of procurement contracts based upon the recommendations of the Audit Committee.

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PART II OTHER INFORMATION

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

The Company held its 2003 Annual Meeting of Stockholders (Annual Meeting) on Tuesday, May 6, 2003. The meeting was held to elect seven directors to serve until the 2004 Annual Meeting of Stockholders, to approve the Spinnaker Exploration Company 2003 Stock Option Plan and to ratify the selection of KPMG LLP as independent auditors of the Company for the fiscal year ending December 31, 2003.

The For column represents affirmative votes by holders of Common Stock represented by either proxy or at the Annual Meeting. Accordingly, abstentions and broker non-votes had the same effect as a vote against a director. The results of the voting related to the election of the nominees for director were as follows:

Name	For	Withheld
Roger L. Jarvis	29,909,282	301,026
Howard H. Newman	29,909,282	301,026
Jeffrey A. Harris	29,908,282	302,026
Michael E. McMahon	29,909,282	301,026
Sheldon R. Erikson	29,909,282	301,026
Michael G. Morris	29,909,282	301,026
Michael E. Wiley	29,909,282	301,026

Stockholders voted 26,583,167 shares for and 3,608,908 shares against the proposal to approve the Spinnaker Exploration Company 2003 Stock Option Plan, with 18,233 votes abstaining.

Stockholders voted 29,930,866 shares for and 268,737 shares against the proposal to ratify the selection of KPMG LLP as independent auditors of the Company for the fiscal year ending December 31, 2003, with 10,705 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, 2003 and filed on May 1, 2003 furnished first quarter 2003 earnings and operations information through April 29, 2003 pursuant to Item 9, Regulation FD Disclosure and Item 12, Results of Operations and Financial Condition.

A Current Report on Form 8-K dated May 6, 2003 and filed on May 8, 2003 announced the appointment of Scott A. Griffiths as Executive Vice President and Chief Operating Officer pursuant to Item 9, Regulation FD Disclosure.

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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 13, 2003	By:	/s/ ROBERT M. SNELL
		Robert M. Snell
		Vice President, Chief Financial
		Officer and Secretary
Date: August 13, 2003	By:	/s/ JEFFREY C. ZARUBA
		Jeffrey C. Zaruba
		Vice President, Treasurer and
		Assistant Secretary

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CERTIFICATION OF

PRINCIPAL EXECUTIVE OFFICER

OF SPINNAKER EXPLORATION COMPANY

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT

I, Roger L. Jarvis, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Spinnaker Exploration Company;

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

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

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

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

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

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

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

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

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

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

Date: August 13, 2003

/s/ ROGER L. JARVIS

Name: Roger L. Jarvis

Title: Chief Executive Officer

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CERTIFICATION OF

PRINCIPAL FINANCIAL OFFICER

OF SPINNAKER EXPLORATION COMPANY

PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT

I, Robert M. Snell, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Spinnaker Exploration Company;

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

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

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

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

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

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

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

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

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

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

Date: August 13, 2003

/s/ ROBERT M. SNELL

Name: Robert M. Snell

Title: Chief Financial Officer

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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
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