SPINNAKER EXPLORATION CO
Form 10-Q
August 09, 2005
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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, 2005

¨ **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 8, 2005 was 34,136,776.

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SPINNAKER EXPLORATION COMPANY

Form 10-Q

For the Three and Six Months Ended June 30, 2005

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SPINNAKER EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share data)

	As of June 30, 2005 (Unaudited)	As of December 31, 2004
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 7,798	$ 21,830
Accounts receivable, net of allowance for doubtful accounts of $3,232 as of June 30, 2005 and December 31, 2004, respectively	62,289	48,785
Hedging assets		2,829
Deferred tax assets	41,953	
Other	7,752	3,467
Total current assets	119,792	76,911
PROPERTY AND EQUIPMENT:		
Oil and gas, on the basis of full-cost accounting:		
Proved properties	1,593,007	1,447,824
Unproved properties and properties under development, not being amortized	178,141	148,277
Other	7,129	6,651
	1,778,277	1,602,752
Less Accumulated depreciation, depletion and amortization	(634,308)	(541,615)
Total property and equipment	1,143,969	1,061,137
OTHER ASSETS	1,148	12,883
Total assets	$ 1,264,909	$ 1,150,931
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 30,479	$ 34,692
Accrued liabilities and other	62,206	47,264
Hedging liabilities	11,848	1,628
Asset retirement obligations, current portion	10,471	6,841
Total current liabilities	115,004	90,425
LONG-TERM DEBT	105,000	105,000
ASSET RETIREMENT OBLIGATIONS	37,460	33,644
DEFERRED INCOME TAXES	163,402	107,776
COMMITMENTS AND CONTINGENCIES EQUITY:		
Preferred stock, $0.01 par value; 10,000,000 shares authorized; no shares issued and outstanding as of June 30, 2005 and December 31, 2004, respectively		
Common stock, $0.01 par value; 50,000,000 shares authorized; 34,105,433 shares	341	339

issued and 34,101,493 shares outstanding as of June 30, 2005 and 33,927,158 shares issued and 33,920,018 shares outstanding as of December 31, 2004		
Additional paid-in capital	617,552	612,920
Retained earnings	234,347	199,882
Less: Treasury stock, at cost, 3,940 shares and 7,140 shares as of June 30, 2005 and December 31, 2004, respectively	(10)	(18)
Unearned compensation	(1,506)	
Accumulated other comprehensive income (loss)	(6,681)	963
Total equity	844,043	814,086
Total liabilities and equity	$ 1,264,909	$ 1,150,931

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,	
	2005	2004	2005	2004
REVENUES	$ 91,970	$ 79,824	$ 170,293	$ 139,615
EXPENSES:				
Lease operating expenses	7,496	6,530	14,143	11,243
Depreciation, depletion and amortization oil and gas properties	42,194	40,403	83,631	69,404
Depreciation and amortization other	316	350	584	696
Impairment of international oil and gas properties	735		8,478	
Accretion of asset retirement obligations	929	538	1,611	1,254
Gain on settlement of asset retirement obligations	(13)		(128)	(126)
General and administrative	4,272	4,227	8,354	7,725
Total expenses	55,929	52,048	116,673	90,196
INCOME FROM OPERATIONS	36,041	27,776	53,620	49,419
OTHER INCOME (EXPENSE):				
Interest income	100	36	197	68
Interest expense, net	(277)	(304)	(548)	(515)
Total other income (expense)	(177)	(268)	(351)	(447)
INCOME BEFORE INCOME TAXES	35,864	27,508	53,269	48,972
Income tax expense	12,660	9,903	18,804	17,630
NET INCOME	$ 23,204	$ 17,605	$ 34,465	$ 31,342
NET INCOME PER COMMON SHARE:				
Basic	$ 0.68	$ 0.52	$ 1.01	$ 0.93
Diluted	$ 0.66	$ 0.51	$ 0.99	$ 0.90
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:				
Basic	34,036	33,719	33,989	33,633
Diluted	34,954	34,779	34,935	34,708

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,	
	2005	**2004**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 34,465	$ 31,342
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	84,215	70,100
Impairment of international oil and gas properties	8,478	
Accretion of asset retirement obligations	1,611	1,254
Gain on settlement of asset retirement obligations	(128)	(126)
Amortization of unearned stock compensation	41	
Deferred income tax expense	18,226	17,630
Other	1,575	415
Change in operating assets and liabilities:		
Accounts receivable	(13,504)	(23,729)
Accounts payable and accrued liabilities	(12,639)	4,653
Other assets	7,450	938
Net cash provided by operating activities	129,790	102,477
CASH FLOWS FROM INVESTING ACTIVITIES:		
Oil and gas properties	(145,266)	(150,974)
Purchases of other property and equipment	(478)	(123)
Net cash used in investing activities	(145,744)	(151,097)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	13,500	43,000
Payments on borrowings	(13,500)	
Proceeds from exercise of stock options	1,922	6,433
Debt issue costs		(101)
Net cash provided by financing activities	1,922	49,332
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(14,032)	712
CASH AND CASH EQUIVALENTS, beginning of year	21,830	15,315
CASH AND CASH EQUIVALENTS, end of period	$ 7,798	$ 16,027
SUPPLEMENTAL CASH FLOW DISCLOSURES:		
Cash paid for interest	$ 2,497	$ 1,365

Cash paid for income taxes	$	160	$	

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, 2005

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, 2004.

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 $0.2 million in the second quarter of 2005 and 2004, respectively, and $0 and $0.2 million in the first six months of 2005 and 2004, 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,

	2005	2004	2005	2004
Net income, as reported	$ 23,204	$ 17,605	$ 34,465	$ 31,342
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	(1,806)	(2,115)	(3,076)	(4,654)
Pro forma net income	$ 21,398	$ 15,616	$ 31,389	$ 26,814
Net income per common share:				
Basic, as reported	$ 0.68	$ 0.52	$ 1.01	$ 0.93
Basic, pro forma	$ 0.63	$ 0.46	$ 0.92	$ 0.80
Diluted, as reported	$ 0.66	$ 0.51	$ 0.99	$ 0.90
Diluted, pro forma	$ 0.59	$ 0.43	$ 0.87	$ 0.75

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On December 16, 2004, the Financial Accounting Standards Board (FASB) revised SFAS No. 123 (revised 2004), Share-Based Payment, (SFAS No. 123R) that will require compensation costs related to share-based payment transactions to be recognized in the financial statements. With limited exceptions, the amount of compensation cost will be measured based on the grant-date fair value of the equity or liability instruments issued. In addition, liability awards will be remeasured each reporting period. Compensation cost will be recognized over the period that an employee provides service in exchange for the award. SFAS No. 123R replaces SFAS No. 123 and supersedes APB Opinion No. 25. Adoption of SFAS No. 123R will require the Company to recognize compensation expense for all awards the Company grants after the date of adoption and for the unvested portion of all options granted that remain outstanding on the date of adoption.

On April 14, 2005, the Securities and Exchange Commission (Commission) announced that it would permit additional time to implement the requirements in SFAS No. 123R. As originally issued by the FASB, public companies were required to implement SFAS No. 123R as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. The Commission will permit companies to implement SFAS No. 123R at the beginning of their next fiscal year, instead of the next reporting period beginning after June 15, 2005 as required by SFAS No. 123R. The Commission is not changing any of the accounting requirements in SFAS No. 123R. The Company will be required to implement SFAS No. 123R as of January 1, 2006. All options that the Company granted prior to December 31, 2001 will be fully vested prior to adoption of SFAS No. 123R and will not be considered as part of the adoption in accordance with the new standard. The Company is currently evaluating the effect of adopting SFAS No. 123R.

In May 2005, Spinnaker s Compensation Committee of the Board of Directors authorized the issuance of 48,275 restricted shares of common stock to all employees. The restricted shares of common stock were issued under the Company s 1999 Stock Incentive Plan and 2001 Stock Incentive Plan. The restricted stock awards are amortized ratably over the vesting period of four years. Spinnaker recorded $1.6 million of unearned compensation in connection with this grant, representing the fair value of the restricted stock awards on the date of grant. Unearned compensation will be recognized as compensation expense within general and administrative expenses and oil and gas properties ratably over the remaining vesting periods. The related compensation expense totaled $0.1 million for the three months ended June 30, 2005.

3. Deferred Tax Assets

The Company was in a tax loss position as of December 31, 2004, and based on the results in the first six months of 2005 and review of the Company s outlook on future operations, the Company expects that it will have taxable income in the next twelve months. As a result, the Company has reclassified from deferred income taxes liability a current deferred tax asset of $37.8 million related to net operating loss carryforwards that it expects to utilize to offset taxable income in the next twelve months. As of June 30, 2005, deferred tax assets also included $4.2 million related to hedging activities.

4. Long-Term Debt

On December 19, 2003, the Company s wholly-owned subsidiary, Spinnaker Exploration Company, L.L.C., entered into a $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. The $50.0 million Tranche B commitment was terminated on July 21, 2005 (with no borrowings then outstanding under Tranche B) upon closing of the spar production facility sale-leaseback transaction related to the Company s deepwater project at Green Canyon Blocks 338/339/382 (Front Runner). See Note 10 for further information concerning the sale-leaseback transaction. Borrowings under Tranche A constitute senior indebtedness. The obligations under the Revolver are fully and unconditionally guaranteed by Spinnaker.

Tranche A is available on a revolving basis through December 19, 2006, the maturity date of the Revolver, and availability is subject to the borrowing base determined by the banks. The borrowing base was $160.0 million as of June 30, 2005. The obligations under Tranche A are unsecured. The borrowing base is re-determined semi-annually by the banks in their sole discretion and in their usual and customary manner. Spinnaker and the banks 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.

The Company has the option to elect to use a base interest rate as described below or the London Interbank Offered Rate (LIBOR) plus, for each such rate, a spread based on the percentage of the borrowing base used at that time. The base rate spread ranges from 0.0% to 0.5%, and the LIBOR spread ranges from 1.25% to 2.0% for Tranche A

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borrowings. The base interest rate under the Revolver is a fluctuating rate of interest equal to the base rate spread plus 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 weighted average interest rate was 4.6% in the first six months of 2005. The commitment fee rate ranges from 0.375% to 0.5%, depending on the borrowing base usage for Tranche A.

As of June 30, 2005, the Company had outstanding borrowings of $105.0 million, and the Company was in compliance with the provisions of the Revolver. Subsequent to June 30, 2005, Spinnaker had no additional borrowings, made a payment of $75.0 million using proceeds from the Front Runner sale-leaseback transaction and issued a letter of credit in the amount of $15.0 million under the Revolver. Current availability is $115.0 million under Tranche A of the Revolver. The Company expects to incur additional borrowings in the remainder of 2005.

5. Asset Retirement Obligations

SFAS No. 143, Accounting for Asset Retirement Obligations requires entities to record liabilities for asset retirement obligations at fair value in the period in which the obligations are incurred and a corresponding increase in the carrying amount of the related long-lived asset. The reconciliation of the beginning and ending asset retirement obligations is as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Asset retirement obligations, beginning of period	$ 45,591	$ 33,974	$ 40,485	$ 32,994
Liabilities incurred	1,645	2,261	6,484	2,834
Liabilities settled (1)	(381)		(923)	
Accretion expense	929	538	1,611	1,254
Revisions in estimated cash flows	147	(511)	274	(820)
Asset retirement obligations, end of period	$ 47,931	$ 36,262	$ 47,931	$ 36,262

(1) The costs associated with asset retirements in the second quarter of 2005 were approximately $0.4 million, resulting in a gain on settlement of asset retirement obligations of less than $0.1 million. The costs associated with asset retirements in the first six months of 2005 were approximately $0.8 million, resulting in a gain on settlement of asset retirement obligations of approximately $0.1 million.

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. The natural gas swap contracts and collar arrangements will settle based on the reported settlement price on the NYMEX for the last trading day of each month. The crude oil swap contracts and collar arrangements will settle based on the average of the settlement price for each commodity business day in the contract month.

In a swap transaction, the counterparty is required to make a payment to Spinnaker for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. Spinnaker 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. In a collar arrangement, the counterparty is required to make a payment to Spinnaker for the difference between the fixed floor price and the settlement price if the settlement price is below the fixed floor price. Spinnaker 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 prices. As of June 30, 2005, Spinnaker s commodity price risk management positions in swap contracts and collar arrangements were as follows:

Natural Gas

	Fixed Price Swaps		**Collars**		
	Average Daily Volume	**Weighted Average Price**	**Average Daily Volume**	**Weighted Average Price (Per MMBtu)**	
Period	**(MMBtus)**	**(Per MMBtu)**	**(MMBtus)**	**Floor**	**Ceiling**
Third Quarter 2005	10,000	$ 6.40		$	$
Fourth Quarter 2005	3,370	6.40			

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Oil

	Fixed Price Swaps		Collars		
				Weighted Average Price (Per Bbl)	
Period	Average Daily Volume (Bbls)	Weighted Average Price (Per Bbl)	Average Daily Volume (Bbls)	Floor	Ceiling
Third Quarter 2005	1,000	$ 39.69	3,000	$ 38.67	$ 44.73
Fourth Quarter 2005	1,000	38.78	3,000	38.67	44.73

The Company reported a net liability of $11.8 million and a net asset of $1.2 million related to financial derivative contracts as of June 30, 2005 and December 31, 2004, respectively. Amounts related to hedging activities were as follows (in thousands):

	As of June 30, 2005	As of December 31, 2004
Current assets:		
Hedging assets	$	$ 2,829
Deferred tax asset related to hedging activities	4,182	
Current liabilities:		
Hedging liabilities	$ 11,848	$ 1,628
Deferred tax liability related to hedging activities		432
Equity:		
Accumulated other comprehensive income (loss)	$ (6,681)	$ 963

The ineffective component of derivatives and net hedging gains (losses) were recorded in revenues in the three and six months ended June 30, 2005 and 2004 as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Ineffective component of derivatives	$ 160	$	$ (1,328)	$
Net hedging losses	$ (3,719)	$ (3,285)	$ (3,126)	$ (1,546)

Based on future oil and gas prices as of June 30, 2005, the Company would reclassify a net loss of approximately $6.7 million from accumulated other comprehensive income (loss) to earnings in the remainder 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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7. Earnings Per Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Numerator:				
Net income available to common stockholders	$ 23,204	$ 17,605	$ 34,465	$ 31,342
Denominator:				
Basic weighted average number of shares	34,036	33,719	33,989	33,633
Dilutive securities:				
Stock options	918	1,060	946	1,075
Diluted adjusted weighted average number of shares and assumed conversions	34,954	34,779	34,935	34,708
Net income per common share:				
Basic	$ 0.68	$ 0.52	$ 1.01	$ 0.93
Diluted	$ 0.66	$ 0.51	$ 0.99	$ 0.90

8. Comprehensive Income

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Net income	$ 23,204	$ 17,605	$ 34,465	$ 31,342
Other comprehensive income (loss), net of tax:				
Net change in fair value of derivative financial instruments	1,193	(943)	(9,667)	(3,305)
Financial derivative settlements reclassified to income	2,407	2,102	2,023	989
Comprehensive income	$ 26,804	$ 18,764	$ 26,821	$ 29,026

9. Impairment of International Oil and Gas Properties

The Company recorded an impairment charge of $0.7 million and $8.5 million in the three and six months ended June 30, 2005, respectively, as a result of an unsuccessful well in its West African venture. The transfer of the 12.5% interest to the Company is still pending various approvals within the Nigerian government.

10. Subsequent Event

Effective July 21, 2005, Spinnaker consummated a sale-leaseback transaction under which the Company sold its 25% undivided interest in the Front Runner spar production facility for $75.0 million. This lease has an initial 12-year term that expires on July 21, 2017 and has a full-term effective interest rate of 3.6%. The lease includes a fixed-price early buy-out option exercisable by Spinnaker in year seven of the lease term. The effective interest rate for the seven-year term is 6.4%. The lease also grants the Company an option to purchase the spar production facility at fair market value at the end of the lease term. The Company will make quarterly rental payments over the term of the lease based upon a fixed payment schedule set forth in the lease.

Spinnaker issued a guaranty, also effective July 21, 2005, guaranteeing the rental payments and other obligations. The guaranty is limited to the payments as they become due. The Company must also comply with certain on-going financial and operating covenants related to Front Runner.

Spinnaker used the $75.0 million proceeds from the sale-leaseback transaction to pay outstanding borrowings under the Revolver on July 21, 2005. In connection with the transaction, the $50.0 million Tranche B commitment under the Revolver was terminated on July 21, 2005, and a letter of credit in the amount of $15.0 million was issued under the Revolver.

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Cautionary Statement About Forward-Looking Statements

In this quarterly report on Form 10-Q (Quarterly Report), unless the context requires otherwise, when we refer to Spinnaker, the Company, we, us or our we are describing Spinnaker Exploration Company and its subsidiaries.

Some of the information in this Quarterly Report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). These forward-looking statements may be identified by the use of the words anticipate, believe, contemplate, estimate, expect, may, plan, will, would ar expressions that contemplate future events. Forward-looking statements include all statements under Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations and elsewhere in this Quarterly Report involving the discussion of the following:

- 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;
- marketing of oil and gas;
- operating costs and other expenses;
- cash flow and anticipated liquidity; and
- prospect development and property acquisitions.

Although we believe that these forward-looking statements are based on reasonable assumptions, our expectations may not occur and we cannot provide assurance that the anticipated future operating results will meet our expectations or be achieved. Numerous factors, risks and uncertainties could cause our actual future results to differ materially from the results implied by these or other forward-looking statements made by us or on our behalf. These factors include, among other things:

the risks associated with exploration;

delays in anticipated production start-up dates;

shut-ins of production for platform, pipeline and facility maintenance, additions and removals;

potential mechanical failure or under-performance of significant wells;

the relatively short production lives of certain properties;

the concentration of production and reserves in a small number of properties;

maturity of the Gulf of Mexico shelf;

oil and gas price volatility;

our hedging activities;

our ability to find, replace, develop and acquire oil and gas reserves;

uncertainties in the estimation of proved reserves and in the projection of future rates of production and the timing and amount of development expenditures;

downward revisions of proved reserves and the related negative impact on the depreciation, depletion and amortization (DD&A) rate;

write-downs of oil and gas properties if oil and gas prices decline, proved reserves are revised downward or our finding and development costs continue to increase;

operating hazards attendant to the oil and gas business;

drilling and completion risks, which costs are generally not recoverable from third parties or insurance;

weather risks and natural disasters;

availability and cost of material and equipment;

actions or inactions of third-party operators of our properties;

risks inherent in international operations;

our ability to find and retain skilled personnel;

availability of capital;

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- the strength and financial resources of competitors and customers;
- regulatory developments;
- environmental risks; and
- general economic conditions.

For additional discussion of these and other factors, risks and uncertainties, see Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations contained in this Quarterly Report. You should pay particular attention to the risk factors and cautionary statements described in our annual report on Form 10-K for the year ended December 31, 2004. The forward-looking statements speak only as of the date made, and we undertake no obligation to update such forward-looking statements.

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

Executive Overview

Our primary objective since inception has been to assemble a large 3-D seismic database and focus on exploration activities in the Gulf of Mexico because we believe that this area represents one of the most attractive exploration regions in North America. We also believe that 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 have also evaluated onshore and offshore opportunities outside the Gulf of Mexico in the past. In order to diversify our operations and apply our skill set to other opportunities, we entered into a farm-out agreement in December 2004 covering a 12.5% interest in OPL Block 256 offshore Nigeria from Devon Energy Corporation (Devon). The transfer of interest is pending various approvals within the Nigerian government. This opportunity gives us exposure to a large acreage position that contains multiple prospects in a prolific basin. We expect our capital requirements for exploratory activities in connection with this venture to be approximately $50 million to $60 million over a two to three year period. The first well offshore Nigeria was determined to be unsuccessful in April 2005. As a result, we recorded an $8.5 million pre-tax impairment charge related to our international oil and gas properties in the first six months of 2005. We have a commitment to drill a minimum of two additional exploratory wells on OPL Block 256, including one well we expect to drill later this year.

Second quarter 2005 financial and operating highlights were as follows:

- Net income was $23.2 million, or $0.66 per diluted share, up 31% from second quarter 2004 net income of $17.6 million, or $0.51 per diluted share.
- Revenues were $92.0 million, up 15% from second quarter 2004 revenues of $79.8 million, and were primarily impacted by a 19% increase in the average commodity price, partially offset by the impact of a 4% decrease in production.

Production was 13.0 Bcfe, down 4% from second quarter 2004 production of 13.6 Bcfe. Oil revenues increased 95% as a result of a 46% increase in oil production and a 34% increase in the average oil price, and natural gas revenues decreased 18% as a result of a 26% decrease in natural gas production, partially offset by an 11% increase in the average natural gas price.

Proved oil and gas reserves were 373.3 Bcfe, up 22% from year-end 2004 proved reserves of 306.7 Bcfe.

We had $7.8 million in cash and cash equivalents and outstanding borrowings of $105.0 million under the Revolver as of June 30, 2005. We have experienced and expect to continue to experience substantial capital requirements. We incurred capital costs of approximately $175.5 million in the first six months of 2005, including $84.2 million in the second quarter. Additionally, we have had negative working capital at the end of each of the past four years. Excluding current deferred tax assets of $42.0 million, our working capital deficit was $37.2 million as of June 30, 2005 compared to a deficit of $13.5 million as of December 31, 2004. We have capital expenditure plans for 2005 totaling approximately $310.0 million. We believe that cash flows from operations and proceeds from available borrowings under the Revolver 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 were smaller and had less impact on our operating results than those prior to that time, resulting in a negative impact on our subsequent production and reserve growth and an increase in our DD&A rate per Mcfe through March 31, 2005. Additionally, several of our discoveries since mid-2001 were in the deep water where longer lead times are required before first production. In particular, we had our first discovery at Front Runner in early 2001 and production commenced in December 2004. Proved reserve additions in the second quarter of 2005 contributed to a 22% increase in reserves from year-end 2001 and an 8% decrease in the second quarter 2005 DD&A rate compared to the first quarter 2005 DD&A rate.

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Production

Since inception, 86% of our total production has been natural gas and related natural gas liquids, including 61% in the second quarter of 2005. Oil production increased 46% in the second quarter of 2005 compared to the second quarter of 2004 primarily due to production at Front Runner. Five additional wells will be completed at the Front Runner spar production facility as ramp-up activities continue. Considering the oil and condensate production from deepwater projects in 2005, we anticipate that the historical concentration in natural gas production will decrease to approximately one-half of total production by year-end 2005. As a result, our revenues, profitability and cash flows will be less sensitive to natural gas prices and more sensitive to oil 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 on the shelf and in deep water 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. Our near-term production growth is dependent upon the success of our shelf drilling activities since large deepwater development projects require significantly more time before production commences.

Drilling Activities and Oil and Gas Property Costs

From inception through June 30, 2005, we participated in drilling 183 wells in the Gulf of Mexico resulting in 109 discoveries. Historically, most of the wells we drilled were on the shelf. However, we are transitioning to more deepwater operations. Prior to 2001, we drilled nine deepwater wells, three of which were successful. Since 2001 and through June 30, 2005, we have drilled 35 deepwater wells, 23 of which were successful. Our most significant deepwater projects include oil discoveries at Front Runner and at Mississippi Canyon 734 (Thunder Hawk) and natural gas discoveries in the Eastern Gulf of Mexico at DeSoto Canyon Blocks 618/619/620/621 (Eastern Gulf Project) and at Mississippi Canyon 961 (Q). Front Runner commenced production in December 2004. The Eastern Gulf Project development plan is complete. Our fields, along with several other dedicated fields in the Eastern Gulf, will be developed via subsea tieback to a floating production facility located in Mississippi Canyon 920 that will be capable of processing 850 MMcf of natural gas per day. We own 10.6% of the processing rights associated with this facility and the export pipelines. We anticipate first production from the Eastern Gulf Project and Q in 2007. We are currently evaluating development options at Thunder Hawk.

We participated in two successful wells in four attempts in the second quarter of 2005. Capital costs incurred totaled $84.2 million in the second quarter of 2005, including approximately $22.4 million for leasehold and other acquisition activities, $37.4 million for exploration activities, $24.2 million for development activities and $0.2 million for acquisitions of other property and equipment.

Our current capital expenditure budget for 2005 is approximately $310.0 million, including $190.0 million for exploration activities and geological and geophysical expenditures, $75.0 million for development activities, $42.0 million for leasehold acquisitions and $3.0 million for other property and equipment. We currently plan to drill and evaluate 14 wells in the remainder of 2005, including nine wells on the Gulf of Mexico shelf, four wells in the deep water of the Gulf of Mexico and one additional deepwater well in West Africa. Exploration and development activities in deep water require significant capital commitments. If we experience continued success in our exploration efforts in 2005, currently budgeted capital requirements in 2005 may increase.

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 we will incur in the future to produce the oil and gas reserves and an estimate of the costs to abandon wells, platforms, facilities and pipelines after reservoirs are depleted. However, other factors must also be considered when relying on the DD&A rate as a measure for evaluating a company s finding and development costs per Mcfe. In most cases, the total estimated resource of a reservoir is not usually proved with only one well, and the initial proved reserves are generally burdened with 100% of the development costs as well as any future development costs. In addition, the costs of successful wells may impact the DD&A rate before associated proved reserves are booked in some instances.

The DD&A rate per Mcfe is calculated quarterly and increased 9% to $3.24 in the second quarter of 2005 from $2.97 in the second quarter of 2004. The DD&A rate decreased 8% in the second quarter of 2005 from $3.51 in the first quarter of 2005. Of the $0.27 decrease in the DD&A rate from the first quarter of 2005, approximately $0.31 related to three successful operations, offset in part by $0.04 related to increased future development and other costs.

Proved Oil and Gas Reserves

We have achieved reserve growth through exploration activities and have not acquired any reserves through acquisition activities. As of June 30, 2005, Ryder Scott Company, L.P. (Ryder Scott) estimated net proved reserves at approximately 373.3 Bcfe, with a present value of future net cash flows (before income taxes) of approximately $1.605 billion. Proved reserves were up 22% from the end of 2004. Oil and condensate reserves were 46% of total proved reserves, and proved undeveloped reserves were approximately 66% of total proved reserves as of June 30, 2005. Front Runner represented approximately 40% of our total proved undeveloped reserves. Our proved reserve additions in the first half of 2005 totaled approximately 91.4 Bcfe. For the first six months of 2005, we replaced 369% of production. Three fields, including Front Runner, Thunder Hawk and Q, comprise approximately 60% of our total proved reserves. Thunder Hawk and Q are in active development and are expected to commence production in 2007 or 2008.

Oil and Gas Prices and Hedging Activities

Oil and gas prices 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 oil and gas that we can economically produce. Oil and gas prices have been extremely volatile recently as a result of various factors, including weather, industrial demand and uncertainty related to the ability of the energy industry to provide supply to meet future demand. There are questions whether fundamentals support current prices.

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in oil and gas prices and to achieve more predictable cash flow. However, these contracts limit the benefits we would realize if prices increase. We recorded net hedging losses of $3.7 million and $3.3 million in the second quarter of 2005 and 2004, respectively, and net hedging losses of $3.1 million and $1.5 million in the first six months of 2005 and 2004, respectively. If oil and gas prices stabilize at current levels, we will incur additional hedging losses in the remainder of 2005. Major challenges related to our hedging activities include a determination of the proper production volumes to hedge and acceptable commodity price levels for each hedge transaction.

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

Critical Accounting Policies

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates include DD&A of proved oil and gas properties. Oil and gas reserve estimates, which are the basis for unit-of-production DD&A and the full cost ceiling test, are inherently imprecise and are expected to change as future information becomes available. In addition, alternatives may exist among various accounting methods. In such cases, the choice of accounting method may also have a significant impact on reported amounts. Our critical accounting policies are as follows:

Full Cost Method of Accounting

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

We use the full cost method of accounting for investments in oil and gas properties. Under this method, cost centers are established on a country-by-country basis, and 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, and geological and geophysical service costs. Development costs include the costs of drilling development wells, completions, platforms, facilities, pipelines and the costs related to the retirement of these assets. Costs associated with production and general corporate activities are expensed in the period incurred. Sales of oil and gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved oil and gas reserves.

Application of the full cost method of accounting for oil and gas properties generally results in higher capitalized costs, no exploration costs and higher DD&A rates than the application of the successful efforts method of accounting. Although some of these costs will ultimately result in no additional proved 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.

Since inception, we have had a single cost center for our U.S. Gulf of Mexico operations. In connection with our West African venture, we have a separate cost center for our Nigerian operations.

Proved 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 proved oil and gas reserves.

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

Depreciation, Depletion & Amortization

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 on a quarterly basis using the unit-of-production method. The calculation is based on quarterly production and estimates of proved reserves. Unevaluated costs are excluded from the amortization base until the properties associated with these costs are evaluated. In addition to costs associated with evaluated properties, the amortization base includes estimated future development costs and dismantlement, restoration and abandonment costs and estimated salvage values of platforms and other equipment 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, 2005, we excluded from the amortization base estimated future expenditures of $28.9 million associated with common development costs for our 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

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established upon completion of the Front Runner project. If the $28.9 million had been included in the amortization base as of June 30, 2005, and no additional reserves were assigned to the Front Runner project, the DD&A rate would have been $3.31 per Mcfe, or an increase of $0.07 over the actual second quarter 2005 DD&A rate of $3.24 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.

Full Cost Ceiling

Under full cost accounting rules, total capitalized costs within each of our cost centers are limited to a ceiling equal to the present value of future net cash flows from proved oil and gas reserves located within the applicable region, discounted at 10% per annum, plus the lower of cost or fair value of unproved properties less income tax effects (the ceiling limitation). We perform a quarterly ceiling test to determine whether the net book value of our full cost amortization base within each of our cost centers exceeds the ceiling limitation. If capitalized costs, net of accumulated DD&A, less related deferred taxes are greater than the ceiling limitation, a write-down or impairment of the full cost amortization base is required. A write-down of the carrying value of oil and gas properties is a non-cash charge that reduces earnings and typically results in lower DD&A expense in future periods.

In accordance with Commission guidelines, we include estimated future cash flows from our hedging program in our ceiling test calculation. In addition, subsequent to the adoption of SFAS No. 143, the future cash outflows associated with the settlement of asset retirement obligations are not included in the computation of the discounted present value of future net cash flows for the purposes of the ceiling test calculation.

In calculating the ceiling test for our U.S. cost center as of June 30, 2005, we estimated a full cost ceiling cushion of $456.0 million, using prices of $7.11 per Mcf of natural gas, $52.32 per barrel of oil and $27.34 per barrel of natural gas liquids. Considering the volatility of oil and gas 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. Capitalized costs related to our operations in Nigeria are subject to a separate ceiling limitation as the costs are evaluated. If oil and gas 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 costs, delay rentals, geological and geophysical costs, wells in-progress and wells pending determination.

Geological and geophysical costs, including 3-D seismic data costs and related seismic hardware and software costs, are included in the full cost amortization base as incurred when such costs cannot be associated with specific unevaluated properties for which we own a direct interest. Seismic data costs are associated with specific unevaluated properties if the seismic data may be used to evaluate acreage that is covered by a leasehold interest owned by Spinnaker. We make this determination based on an analysis of leasehold and seismic maps and discussions with our management and exploration managers. Seismic hardware and software costs are associated with specific unevaluated properties if the hardware and software was acquired specifically to process or reprocess certain 3-D seismic data that covers an area or trend containing a leasehold interest owned by Spinnaker. We make this determination based on discussions with our management and information technology and seismic processing specialists. When such seismic data, hardware and software costs can be associated with specific unevaluated properties and excluded from the full cost amortization base, we allocate the costs based on management s judgment of the potential economic value to be realized upon determination of whether or not proved reserves can be assigned to the properties. Significant assumptions used by management in determining the potential economic value of an owned leasehold interest include the number of successful and unsuccessful wells drilled within and around the lease and trend, the number of prospects on the lease and the size of the potential resource associated with the lease.

Unevaluated leasehold costs, delay rentals and geological and geophysical costs associated with specific properties are transferred to the amortization base either upon determination of whether or not proved reserves can be assigned to the properties or if impairment has occurred. The costs of drilling exploratory dry holes are transferred to the amortization base immediately upon determination that the well is unsuccessful. The costs associated with wells in-progress and wells pending determination are transferred to the amortization base upon determination of whether or not proved reserves can be assigned to the properties.

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Leasehold Costs

In September 2004, the FASB issued FASB Staff Position (FSP) No. FAS 142-2, Application of FASB Statement No. 142, Goodwill and Other Intangible Assets to Oil and Gas Producing Entities. This FSP confirms that SFAS No. 142 did not change the balance sheet classification or disclosure requirements for drilling and mineral rights of oil and gas producing entities. We classify the costs of oil and gas drilling and mineral rights as property and equipment.

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, 2005, 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 oil and gas prices and to achieve more predictable cash flow. These hedging arrangements take the form of swap contracts or cashless collars and are placed with major trading counterparties.

Stock-Based Compensation

SFAS No. 148 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 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 elected 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.

On December 16, 2004, the FASB revised SFAS No. 123 that will require compensation costs related to share-based payment transactions to be recognized in the financial statements. With limited exceptions, the amount of compensation cost will be measured based on the grant-date fair value of the equity or liability instruments issued. In addition, liability awards will be remeasured each reporting period. Compensation cost will be recognized over the period that an employee provides service in exchange for the award. SFAS No. 123(R) replaces SFAS No. 123 and supersedes APB Opinion No. 25. Adoption of SFAS No. 123R will require us to recognize compensation expense for all awards we grant after the date of adoption and for the unvested portion of all options granted that remain outstanding on the date of adoption.

On April 14, 2005, the Commission announced that it would permit additional time to implement the requirements in SFAS No. 123R. As originally issued by the FASB, public companies were required to implement SFAS No. 123R as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. The Commission will permit companies to implement SFAS No. 123R at the beginning of their next fiscal year, instead of the next reporting period beginning after June 15, 2005 as required by SFAS No. 123R. The Commission is not changing any of the accounting requirements in SFAS No. 123R. We will be required to implement SFAS No. 123R as of January 1, 2006. All options that we granted prior to December 31, 2001 will be fully vested prior to adoption of SFAS No. 123R and will not be considered as part of the adoption in accordance with the new standard. We are currently evaluating the effect of adopting SFAS No. 123R.

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Related Parties

We purchase oilfield goods, equipment and services from Cooper Cameron Corporation (Cooper Cameron) and National-Oilwell Varco, Inc. (National-Oilwell) and other oilfield services companies in the ordinary course of business. We incurred charges of less than $0.1 million in the first six months of 2005 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. We incurred charges of less than $0.1 million in the first six months of 2005 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 Cooper Cameron s and National-Oilwell s total revenues in the first six months of 2005 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 its respective segments of the oilfield services sector. We could be at a disadvantage if we were to discontinue using these companies as vendors.

New Accounting Pronouncements

On December 16, 2004, the FASB issued SFAS No. 153, Exchanges of Nonmonetary Assets, an amendment of APB Opinion No. 29, to clarify the accounting for nonmonetary exchanges of similar productive assets. SFAS No. 153 eliminates the exception from the fair value measurement for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. SFAS No. 153 will be applied prospectively and is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. We do not expect the adoption of SFAS No. 153 to have a material impact on our consolidated financial statements.

Proved Oil and Gas Reserves

The following table presents estimated net proved oil and gas reserves and the related net present value of the reserves as of June 30, 2005 as prepared by Ryder Scott. 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 oil and gas reserves we own.

The present value of future net cash flows as of June 30, 2005 was determined using prices of $7.11 per Mcf of natural gas, $52.32 per barrel of oil and $27.34 per barrel of natural gas liquids as of June 30, 2005.

	Proved Reserves		
	Developed	**Undeveloped**	**Total**
Natural gas (MMcf)	61,008	121,840	182,848

Oil and condensate (MBbls)	9,074	19,481	28,555
Natural gas liquids (MBbls)	1,710	1,473	3,183
Total proved reserves (MMcfe)	125,706	247,569	373,275
Present value of future net cash flows (before income taxes) discounted at 10% (in thousands)(1)	$ 678,554	$ 926,405	$ 1,604,959

(1) Excludes a net pre-tax unrealized loss of $11.8 million for the effects of hedging activities using oil and gas prices in effect as of June 30, 2005.

The process of estimating oil and gas reserves is complex. Ryder Scott prepares our proved oil and gas 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.

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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, 2005, approximately 85% 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.

As of June 30, 2005, approximately 66% of our proved oil and gas reserves were undeveloped and primarily related to Front Runner, Thunder Hawk and Q. We anticipate that a large percentage of our proved undeveloped reserves at Front Runner, although not all, will be re-categorized as proved developed reserves as additional wells in the Front Runner field are completed and commence production in 2005 and 2006. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make these capital expenditures. Although we estimate our 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.

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

Results of Operations

Three Months Ended June 30, 2005 as Compared to the Three Months Ended June 30, 2004

	Three Months Ended June 30,			
	2005	2004	Variance	
Production:				
Natural gas (MMcf)	7,041	9,463	(2,422)	(26)%
Oil and condensate (MBbls)	849	582	267	46%
Natural gas liquids (MBbls)	148	109	39	36%
Total (MMcfe)	13,023	13,611	(588)	(4)%
Revenues (in thousands):				
Natural gas	$ 49,283	$ 59,737	$ (10,454)	(18)%
Oil and condensate	41,523	21,311	20,212	95%
Natural gas liquids	4,487	2,420	2,067	85%
Net hedging income (loss)	(3,719)	(3,285)	(434)	(13)%
Other	396	(359)	755	210%
Total	$ 91,970	$ 79,824	$ 12,146	15%
Average realized sales price per unit:				
Natural gas revenues from production (per Mcf)	$ 7.00	$ 6.31	$ 0.69	11%
Effects of hedging activities (per Mcf)	(0.04)	(0.34)	0.30	88%

Average realized price (per Mcf)	$ 6.96	$ 5.97	$ 0.99	17%
Oil and condensate revenues from production (per Bbl)	$ 48.92	$ 36.61	$ 12.31	34%
Effects of hedging activities (per Bbl)	(4.03)		(4.03)	
Average realized price (per Bbl)	$ 44.89	$ 36.61	$ 8.28	23%
Natural gas liquids revenues from production (per Bbl)	$ 30.24	$ 22.26	$ 7.98	36%
Effects of hedging activities (per Bbl)				
Average realized price (per Bbl)	$ 30.24	$ 22.26	$ 7.98	36%
Total revenues from production (per Mcfe)	$ 7.32	$ 6.13	$ 1.19	19%
Effects of hedging activities (per Mcfe)	(0.29)	(0.24)	(0.05)	(21)%
Total average realized price (per Mcfe)	$ 7.03	$ 5.89	$ 1.14	19%
Expenses (per Mcfe):				
Lease operating expenses	$ 0.58	$ 0.48	$ 0.10	21%
Depreciation, depletion and amortization oil and gas properties	$ 3.24	$ 2.97	$ 0.27	9%

Revenues and Production

Revenues increased $12.1 million, or 15%, in the second quarter of 2005 compared to the second quarter of 2004. The increase was primarily due to a 19% higher average commodity price and a $0.8 million net increase in other revenues, partially offset by the impact of 4% lower production and a $0.4 million increase in hedging losses.

Production decreased approximately 0.6 Bcfe, or 4%, in the second quarter of 2005 compared to the second quarter of 2004. Average daily production in the second quarter of 2005 was 143 MMcfe compared to 150 MMcfe in the second quarter of 2004. Natural gas revenues decreased $10.5 million, or 18%, due primarily to lower production of 2.4 Bcf, or 26%, partially offset by an 11% higher average price in the second quarter of 2005. Excluding the effects of hedging activities, the second quarter 2005 average natural gas price was $7.00 per Mcf compared to $6.31 per Mcf in the same period of 2004. Oil and condensate revenues increased $20.2 million, or 95%, due primarily to an increase in production of 267 MBbls, or 46%, and a 34% higher average price. The increase in oil production was primarily due to Front Runner. Front Runner commenced production in December 2004, and four of the nine wells have been completed and are producing in 2005 as ramp-up activities continue. Excluding the effects of hedging activities, the second quarter 2005 average oil price was $48.92 per barrel compared to $36.61 per barrel in the same period of 2004. Natural gas liquids revenues increased $2.1 million, or 85%, in the second quarter of 2005 compared to the same period of 2004 based on natural gas production and related processing requirements.

Lease Operating Expenses

Lease operating expenses are costs incurred to operate and maintain wells and related equipment and facilities. These costs may include, among others, workover expenses, labor, materials, supplies, property taxes, insurance, severance taxes and transportation, gathering and processing expenses. Lease operating expenses increased $1.0 million, or 15%, in the second quarter of 2005 compared to the same period in 2004. Of the total increase, approximately $1.7 million was related to lease operating expenses at Front Runner, our deepwater project that commenced production in December 2004, and $0.3 million related to lease operating expenses on other blocks where production commenced subsequent to the second quarter of 2004, offset in part by a net $1.0 million decrease in costs associated with producing blocks as of June 30, 2004.

Depreciation, Depletion and Amortization

DD&A increased $1.8 million, or 4%, in the second quarter of 2005 compared to the second quarter of 2004. Of the total increase in DD&A, $3.5 million related to a higher DD&A rate, offset in part by $1.7 million related to lower production of 0.6 Bcfe. The 9% increase in the DD&A rate per Mcfe to $3.24 in the second quarter of 2005 from $2.97 in the same period of 2004 was primarily due to costs associated with unsuccessful wells since June 30, 2004, a net downward revision to proved reserves in 2004 and higher finding costs associated with certain discoveries due primarily to the timing of reserve recognition.

Impairment of International Oil and Gas Properties

We recorded a $0.7 million impairment charge in the second quarter of 2005 as a result of an unsuccessful well in our West African venture. The transfer of the 12.5% interest to Spinnaker is still pending various approvals within the Nigerian government.

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, Sarbanes-Oxley Section 404 compliance fees, insurance, office rent, travel and entertainment, computer supplies and maintenance and investor relations expenses. General and administrative expenses in the second quarter of 2005 were consistent with expenses in the same period of 2004.

Income Tax Expense

Income tax expense increased $2.8 million, or 28%, due to higher pre-tax income, offset in part by a reduction in the effective tax rate to 35.3% in the second quarter of 2005 from 36.0% in the second quarter of 2004. The effective tax rate was reduced to 35.3% beginning in the first quarter of 2005 due to lower expected deferred state income taxes resulting from a lower state apportionment factor.

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Six Months Ended June 30, 2005 as Compared to the Six Months Ended June 30, 2004

	Six Months Ended June 30,			
	2005	2004	Variance	
Production:				
Natural gas (MMcf)	13,743	17,279	(3,536)	(20)%
Oil and condensate (MBbls)	1,542	914	628	69%
Natural gas liquids (MBbls)	307	190	117	62%
Total (MMcfe)	24,834	23,906	928	4%
Revenues (in thousands):				
Natural gas	$ 91,900	$ 103,935	$ (12,035)	(12)%
Oil and condensate	73,914	32,858	41,056	125%
Natural gas liquids	8,769	4,444	4,325	97%
Net hedging income (loss)	(3,126)	(1,546)	(1,580)	(102)%
Other	(1,164)	(76)	(1,088)	(1,432)%
Total	$ 170,293	$ 139,615	$ 30,678	22%
Average realized sales price per unit:				
Natural gas revenues from production (per Mcf)	$ 6.69	$ 6.02	$ 0.67	11%
Effects of hedging activities (per Mcf)	0.17	(0.09)	0.26	289%
Average realized price (per Mcf)	$ 6.86	$ 5.93	$ 0.93	16%
Oil and condensate revenues from production (per Bbl)	$ 47.95	$ 35.95	$ 12.00	33%
Effects of hedging activities (per Bbl)	(3.58)		(3.58)	
Average realized price (per Bbl)	$ 44.37	$ 35.95	$ 8.42	23%
Natural gas liquids revenues from production (per Bbl)	$ 28.56	$ 23.52	$ 5.04	21%
Effects of hedging activities (per Bbl)				
Average realized price (per Bbl)	$ 28.56	$ 23.52	$ 5.04	21%
Total revenues from production (per Mcfe)	$ 7.03	$ 5.91	$ 1.12	19%
Effects of hedging activities (per Mcfe)	(0.13)	(0.07)	(0.06)	(86)%
Total average realized price (per Mcfe)	$ 6.90	$ 5.84	$ 1.06	18%
Expenses (per Mcfe):				
Lease operating expenses	$ 0.57	$ 0.47	$ 0.10	21%
Depreciation, depletion and amortization oil and gas properties	$ 3.37	$ 2.90	$ 0.47	16%

Revenues and Production

Revenues increased $30.7 million, or 22%, in the first six months of 2005 compared to the first six months of 2004. The increase was primarily due to 4% higher production and a 19% higher average commodity price in the first six months of 2005, partially offset by a $1.6 million increase in hedging losses and a $1.1 million net decrease in other revenues resulting primarily from the ineffective component of derivatives of $1.3 million.

Production increased approximately 0.9 Bcfe, or 4%, in the first six months of 2005 compared to the first six months of 2004 primarily due to Front Runner oil production. Average daily production in the first six months of 2005 was 137 MMcfe compared to 132 MMcfe in the first six months of 2004. Natural gas revenues decreased $12.0 million, or 12%, due primarily to lower production of 3.5 Bcf, or 20%, partially offset by an 11% higher average price in the first six months of 2005. Excluding the effects of hedging activities, the average natural gas price in the first six months of 2005 was $6.69 per Mcf compared to $6.02 per Mcf in the same period of 2004. Oil and condensate revenues increased $41.1 million, or 125%, due primarily to an increase in production of 628 MBbls, or 69%, and a 33% higher average price. Excluding the effects of hedging activities, the average oil price in the first six months of 2005 was $47.95 per barrel compared to $35.95 per barrel in the same period of 2004. Natural gas liquids revenues increased $4.3 million, or 97%, in the first six months of 2005 compared to the same period of 2004 based on natural gas production and related processing requirements.

Lease Operating Expenses

Lease operating expenses increased $2.9 million, or 26%, in the first six months of 2005 compared to the same period in 2004. Of the total increase, approximately $2.8 million was related to lease operating expenses at Front Runner, our deepwater project that commenced production in December 2004, and $0.4 million related to lease operating expenses on other blocks where production commenced subsequent to June 30, 2004, offset in part by a net $0.3 million decrease in costs associated with producing blocks as of June 30, 2004.

Depreciation, Depletion and Amortization

DD&A increased $14.2 million, or 20%, in the first six months of 2005 compared to the first six months of 2004. Of the total increase in DD&A, $11.5 million related to a higher DD&A rate and $2.7 million related to higher production of 0.9 Bcfe. The 16% increase in the DD&A rate per Mcfe to $3.37 in the first six months of 2005 from $2.90 in the same period in 2004 was primarily due to costs associated with unsuccessful wells, a net downward revision to proved reserves in 2004 and higher finding costs associated with certain discoveries due primarily to the timing of reserve recognition.

Impairment of International Oil and Gas Properties

We recorded an $8.5 million impairment charge in the first six months of 2005 as a result of an unsuccessful well in our West African venture.

General and Administrative

General and administrative expenses increased $0.6 million, or 8%, in the first six months of 2005 compared to the first six months of 2004. The increase was primarily due to higher employment-related expenses, legal fees and costs associated with Sarbanes-Oxley Section 404 compliance.

Income Tax Expense

Income tax expense increased $1.2 million, or 7%, due to higher pre-tax income, offset in part by a reduction in the effective tax rate to 35.3% in the first six months of 2005 from 36.0% in the first six months of 2004. The effective tax rate was reduced to 35.3% beginning in the first quarter of 2005 due to lower expected deferred state income taxes resulting from a lower state apportionment factor.

Liquidity and Capital Resources

Our 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 oil and gas prices could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and gas reserves that may be economically produced and access to capital.

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 and offshore Nigeria. Net additions to property and equipment in the first six months of 2005 were $175.5 million. We have capital expenditure plans for 2005 totaling approximately $310.0 million. Based on this level of capital expenditures and current oil and gas prices, we expect our cash flow from operations to exceed our capital expenditures in 2005 for the first time since our inception. We use a systematic risking process to select prospects for drilling. If we experience greater than anticipated success on budgeted projects, capital expenditures will increase.

Oil and gas 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 oil and gas 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 and proceeds from available borrowings under the Revolver 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 acquisition, 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, 2005, we had outstanding borrowings of $105.0 million, and we were in compliance with the provisions of the Revolver. Subsequent to June 30, 2005, we had no additional borrowings, made a payment of $75.0 million using proceeds from the Front Runner sale-leaseback transaction and issued a letter of credit in the amount of $15.0 million under the Revolver. Current availability is $115.0 million under Tranche A of the Revolver. We expect to incur additional borrowings in the remainder of 2005. See *Financing Activities* for more information.

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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

Effective July 21, 2005, we consummated a sale-leaseback transaction under which we sold our 25% undivided interest in our Front Runner spar production facility for $75.0 million. Scheduled lease payments under the initial 12-year term are as follows:

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Capital lease obligation	$ 87,963	$ 10,608	$ 23,471	$ 18,797	$ 35,087

As of June 30, 2005, we had borrowings of $105.0 million outstanding under Tranche A of the Revolver. We used the $75.0 million proceeds from the sale-leaseback transaction to pay outstanding borrowings under the Revolver on July 21, 2005. As of August 8, 2005, we had borrowings of $30.0 million outstanding under Tranche A of the Revolver which are due on December 19, 2006.

Components of Cash Flow

Cash and cash equivalents decreased $14.0 million to $7.8 million as of June 30, 2005. The components of the decrease in cash and cash equivalents included $129.8 million provided by operating activities, $145.7 million used in investing activities and $1.9 million provided by financing activities.

Operating Activities

Net cash provided by operating activities in the first six months of 2005 increased 27% to $129.8 million primarily due to higher commodity prices. Cash flow from operations is dependent upon our ability to increase production through exploration and development activities and oil and gas prices. We have made significant investments to expand our operations in the Gulf of Mexico.

We sell our oil and gas production under fixed and floating market price contracts each month. We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in oil and gas prices and to achieve more predictable cash flow. However, these contracts limit the benefits we would realize if prices increase. See Item 3. Quantitative and Qualitative Disclosures About Market Risk.

As of June 30, 2005, we had working capital of $4.8 million. Excluding current deferred tax assets of $42.0 million, we had negative working capital $37.2 million as of June 30, 2005. 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 $13.5 million in accounts receivable since December 31, 2004 was primarily related to increases of $11.4 million in joint interest billings and $2.8 million in oil and gas revenues receivable, offset in part by a net $0.7 million decrease other receivables. Joint interest billings fluctuate from period to period based on the number of wells we operate and the timing of billings to and collections from other working interest owners. Oil and gas revenues receivable increased primarily due to higher oil volumes and prices in June 2005 compared to December 2004, offset in part by lower natural gas volumes and prices in June 2005 compared to December 2004. Accounts payable and accrued liabilities increased $10.7 million from December 31, 2004. Fluctuations from period to period occur based on exploratory and development activities in progress and the timing of our payments to vendors and other operators.

Investing Activities

Net cash used in investing activities was $145.7 million in the first six months of 2005 and included oil and gas property expenditures of $145.3 million and purchases of other property and equipment of $0.5 million.

As part of our strategy, we explore for oil and gas at deeper drilling depths and in the deep water of the Gulf of Mexico, where operations are more difficult and costly than at shallower drilling depths and in shallower water. 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. Historically, most of the wells we drilled were on the shelf. However, we are transitioning to more deepwater operations. Prior to 2001, we drilled nine deepwater wells, three of which were successful. Since 2001 and through June 30, 2005, we have drilled 35 deepwater wells, 23 of which were successful.

In order to diversify our operations, we entered into a farm-out agreement in December 2004 covering a 12.5% interest in OPL Block 256 offshore Nigeria from Devon. The transfer of interest is pending various approvals within the Nigerian government. We expect our capital requirements for exploratory activities in connection with this venture to be approximately $50 million to $60 million over a two to three year period. The first well offshore Nigeria was determined to be unsuccessful in April 2005. As a result, we recorded an $8.5 million pre-tax impairment charge in the first six months of 2005 related to our international oil and gas properties. We have a minimum of two additional exploratory wells to drill on OPL Block 256, including one well we expect to drill later this year.

We drilled five successful wells in seven attempts in the first six months of 2005. We drilled 27 wells in 2004, 14 of which were successful. Since inception and through June 30, 2005, we drilled 183 wells, 109 of which were successful, representing a success rate of 60%. Dry hole costs, including associated leasehold costs, were approximately $13.0 million in the first six months of 2005. Our current capital expenditure budget for 2005 is approximately $310.0 million, including $190.0 million for exploration activities and geological and geophysical expenditures, $75.0 million for development activities, $42.0 million for leasehold acquisitions and $3.0 million for other property and equipment. We currently plan to drill and evaluate 14 wells in the remainder of 2005, including nine wells on the Gulf of Mexico shelf, four wells in the deep water of the Gulf of Mexico and one additional deepwater well in West Africa. 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.

We settled asset retirement obligations of $0.9 million in the first six months of 2005. Current liabilities include asset retirement obligations of $10.5 million, the settlements of which will depend on the timing of abandonment decisions and equipment availability in 2005.

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, 2005	As of December 31, 2004
Leasehold, delay rentals and seismic data, hardware and software costs	$ 170,410	$ 128,465
Wells in-progress	5,194	3,836
Wells pending determination		14,820
Other	2,537	1,156
Total	$ 178,141	$ 148,277

Financing Activities

Net cash provided by financing activities of $1.9 million in the first six months of 2005 related to proceeds from stock option exercises. We increased our borrowings by $13.5 million and made payments on our borrowings of $13.5 million in the first six months of 2005.

On December 19, 2003, our wholly-owned subsidiary, Spinnaker Exploration Company, L.L.C., entered into a $200.0 million Revolver with a group of eight banks. The Revolver consists of two tranches, Tranche A and Tranche B. The $50.0 million Tranche B commitment was terminated on July 21, 2005 (with no borrowings then outstanding under Tranche B) upon closing of the Front Runner spar production facility sale-leaseback transaction. Borrowings under Tranche A constitute senior indebtedness. The obligations under the Revolver are fully and unconditionally guaranteed by Spinnaker.

Tranche A is available on a revolving basis through December 19, 2006, the maturity date of the Revolver, and availability is subject to the borrowing base determined by the banks. The borrowing base was $160.0 million as of June 30, 2005. The obligations under Tranche A are unsecured. The borrowing base is re-determined semi-annually by the banks in their sole discretion and in their usual and customary manner. Spinnaker and the banks 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.

We have the option to elect to use a base interest rate as described below or the LIBOR plus, for each such rate, a spread based on the percentage of the borrowing base used at that time. The base rate spread ranges from 0.0% to 0.5%, and the LIBOR spread ranges from 1.25% to 2.0% for Tranche A borrowings. The base interest rate under the Revolver is a fluctuating rate of interest equal to the base rate spread plus 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 weighted average interest rate was 4.6% in the first six months of 2005. The commitment fee rate ranges from 0.375% to 0.5%, depending on the borrowing base usage for Tranche A.

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, 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 production facility is specifically permitted.

- Liens are generally prohibited; however, we may grant a lien in connection with the purchase of seismic data, pledges and deposits to secure hedging arrangements not to exceed $15.0 million and lease financing arrangements involving our interest in the Front Runner spar production facility.

- 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 February 8, 2005, Spinnaker and the banks amended the Revolver. The amendment was intended to give us:

the flexibility to engage in business activities through entities other than our principal operating subsidiary, Spinnaker Exploration Company, L.L.C., including activities in international locations;

the ability to make investments and provide guarantees and extensions of credit to entities other than our principal operating subsidiary;

a basket of up to $75.0 million a year to make distributions from our principal operating subsidiary to us, to request letters of credit under the Revolver for activities other than those of our principal operating subsidiary, subject to the limits under the Revolver, and to provide extensions of credit from our principal operating subsidiary to other entities; and

an increase in the aggregate amount of the borrowing base available under the Revolver for letters of credit up to $60.0 million, subject to certain limitations.

Effective July 21, 2005, we consummated a sale-leaseback transaction under which we sold our 25% undivided interest in the Front Runner spar production facility for $75.0 million. This lease has an initial 12-year term that expires on July 21, 2017 and has a full-term effective interest rate of 3.6%. The lease includes a fixed-price early buy-out option exercisable by us in year seven of the lease term. The effective interest rate for the seven-year term is 6.4%. The lease also grants us an option to purchase the spar production facility at fair market value at the end of the lease term. We will make quarterly rental payments over the term of the lease based upon a fixed payment schedule set forth in the lease.

We issued a guaranty, also effective July 21, 2005, guaranteeing the rental payments and other obligations. The guaranty is limited to the payments as they become due. We must also comply with certain on-going financial and operating covenants related to Front Runner.

As of June 30, 2005, we had outstanding borrowings of $105.0 million, and we were in compliance with the provisions of the Revolver. Subsequent to June 30, 2005, we had no additional borrowings, made a payment of $75.0 million using proceeds from the Front Runner sale-leaseback transaction and issued a letter of credit in the amount of $15.0 million under the Revolver. Current availability is $115.0 million under Tranche A of the Revolver. We expect to incur additional borrowings in the remainder of 2005.

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. Oil and gas 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 oil and gas that we can economically produce. We sell our oil and gas production under fixed and floating market price contracts each month. We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in oil and gas prices and to achieve more predictable cash flow. We do not enter into such hedging arrangements for trading purposes. However, these contracts limit the benefits we would realize if prices increase. Our current financial derivative contracts include fixed price swap contracts and cashless collar arrangements that have been placed with major trading counterparties we believe represent minimum credit risks. We cannot provide assurance that these trading counterparties will not become credit risks in the future. Under our current hedging practice, we generally do not hedge more than 66 $^{2}/_{3}$% of our estimated twelve-month production quantities without the prior approval of the Risk Management Committee of our Board of Directors.

We enter into NYMEX related swap contracts and collar arrangements from time to time. The natural gas swap contracts and collar arrangements will settle based on the reported settlement price on the NYMEX for the last trading day of each month. The crude oil swap contracts and collar arrangements will settle based on the average of the settlement price for each commodity business day in the contract month.

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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. In a collar arrangement, the counterparty is required to make a payment to us for the difference between the fixed floor price and the settlement price if the settlement price is below the fixed floor price. We are required to make a payment to the counterparty for the difference between the fixed ceiling price and the settlement price if the settlement price is above the fixed ceiling price. Neither party is required to make a payment if the settlement price falls between the fixed floor and ceiling prices. As of June 30, 2005, our commodity price risk management positions in swap contracts and collar arrangements were as follows:

Natural Gas

	Fixed Price Swaps		Collars		
				Weighted Average Price (Per MMBtu)	
Period	**Average Daily Volume (MMBtus)**	**Weighted Average Price (Per MMBtu)**	**Average Daily Volume (MMBtus)**	**Floor**	**Ceiling**
Third Quarter 2005	10,000	$ 6.40		$	$
Fourth Quarter 2005	3,370	6.40			

Oil

	Fixed Price Swaps		Collars		
				Weighted Average Price (Per Bbl)	
Period	**Average Daily Volume (Bbls)**	**Weighted Average Price (Per Bbl)**	**Average Daily Volume (Bbls)**	**Floor**	**Ceiling**
Third Quarter 2005	1,000	$ 39.69	3,000	$ 38.67	$ 44.73
Fourth Quarter 2005	1,000	38.78	3,000	38.67	44.73

We reported a net liability of $11.8 million and a net asset of $1.2 million related to financial derivative contracts as of June 30, 2005 and December 31, 2004, respectively. Amounts related to hedging activities were as follows (in thousands):

	As of June 30, 2005	As of December 31, 2004
Current assets:		

Hedging assets	$		$	2,829
Deferred tax asset related to hedging activities		4,182		
Current liabilities:				
Hedging liabilities	$	11,848	$	1,628
Deferred tax liability related to hedging activities				432
Equity:				
Accumulated other comprehensive income (loss)	$	(6,681)	$	963

The ineffective component of derivatives and net hedging gains (losses) were recorded in revenues in the three and six months ended June 30, 2005 and 2004 as follows (in thousands):

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2005	**2004**	**2005**	**2004**
Ineffective component of derivatives	$ 160	$	$ (1,328)	$
Net hedging losses	$ (3,719)	$ (3,285)	$ (3,126)	$ (1,546)

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Based on future oil and gas prices as of June 30, 2005, we would reclassify a net loss of approximately $6.7 million from accumulated other comprehensive income (loss) to earnings in the remainder 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.

To calculate the potential effect of the derivative contracts on future revenues, we applied NYMEX oil and gas forward prices as of June 30, 2005 to the quantity of our oil and gas production covered by those derivative contracts as of that date. The following table shows the estimated potential effects of the derivative financial instruments on future revenues (in thousands):

Derivative Instrument	Estimated Decrease in Revenues at Current Prices	Estimated Increase (Decrease) in Revenues with 10% Decrease in Prices	Estimated Decrease in Revenues with 10% Increase in Prices
Natural gas swaps	$ (762)	$ 98	$ (1,630)
Oil swaps	(3,492)	(2,771)	(5,260)
Oil collars	(7,594)	(4,585)	(10,743)

Subsequent to June 30, 2005, the fair value of our open commodity price risk management positions in swap contracts and collar arrangements using average oil and gas forward prices of $63.26 and $8.73, respectively, as of August 5, 2005 was a net liability of approximately $13.6 million, excluding July and August 2005 settlements resulting in losses of $1.8 million. We did not enter into any additional derivative transactions subsequent to June 30, 2005.

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.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of our disclosure controls and procedures, as this term is defined under Rule 13a-15(e) promulgated under the Exchange Act. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2005.

Changes in Internal Control Over Financial Reporting

During the three months ended June 30, 2005, we made no change in our internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II - OTHER INFORMATION

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

We held our 2005 Annual Meeting of Stockholders (Annual Meeting) on Wednesday, May 4, 2005. The meeting was held to elect seven directors to serve until the 2006 Annual Meeting of Stockholders, to approve the Spinnaker Exploration Company 2005 Stock Incentive Plan and to ratify the selection of KPMG LLP as our independent auditors of the Company for the fiscal year ending December 31, 2005.

The results of the voting related to the nominees to serve on our Board of Directors for the ensuing year were as follows:

Name	For	Withheld
Roger L. Jarvis	29,164,661	704,799
Howard H. Newman	29,533,523	335,937
Jeffrey A. Harris	29,581,999	287,461
Michael E. McMahon	29,583,639	285,821
Sheldon R. Erikson	28,527,404	1,342,056
Michael E. Wiley	27,727,831	2,141,629
Walter R. Arnheim	29,583,744	285,716

The results of the voting related to the proposal to approve the Spinnaker Exploration Company 2005 Stock Incentive Plan were as follows:

For:	23,765,378
Against:	2,545,707
Abstain:	11,634
Not Voted:	3,546,741

The results of the voting related to the proposal to ratify the selection of KPMG LLP as independent auditors of the Company for the fiscal year ending December 31, 2005 were as follows:

For:	29,843,742
Against:	19,632
Abstain:	6,086

Item 6. Exhibits.

See Exhibit Index.

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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 8, 2005	By:	/s/ ROBERT M. SNELL
		Robert M. Snell Vice President, Chief Financial Officer and Secretary
Date: August 8, 2005	By:	/s/ JEFFREY C. ZARUBA
		Jeffrey C. Zaruba Vice President, Treasurer and Assistant Secretary

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EXHIBIT INDEX

Exhibit Number	Description
10.1	Spinnaker Exploration Company 2005 Stock Incentive Plan (filed with the Commission on May 10, 2005 as Exhibit 10.17 to our current report on Form 8-K dated May 4, 2005 and incorporated herein by reference)
10.2	Form of Nonstatutory Stock Option Award Agreement for Annual Director Grants (filed with the Commission on May 10, 2005 as Exhibit 10.17.1 to our current report on Form 8-K dated May 4, 2005 and incorporated herein by reference)
10.3	Form of Nonstatutory Stock Option Award Agreement for Discretionary Director Grants (filed with the Commission on May 10, 2005 as Exhibit 10.17.2 to our current report on Form 8-K dated May 4, 2005 and incorporated herein by reference)
10.4	Form of Nonstatutory Stock Option Award Agreement for Employee Grants (filed with the Commission on May 10, 2005 as Exhibit 10.17.3 to our current report on Form 8-K dated May 4, 2005 and incorporated herein by reference)
10.5	Non-Employee Director Compensation Arrangement (filed with the Commission on May 12, 2005 as Exhibit 10.1 to our current report on Form 8-K dated May 6, 2005 and incorporated herein by reference)
10.6	Form of Restricted Stock Award Agreement under the Spinnaker Exploration Company 1999 Stock Incentive Plan (filed with the Commission on May 12, 2005 as Exhibit 10.2 to our current report on Form 8-K dated May 6, 2005 and incorporated herein by reference)
10.7	Form of Restricted Stock Award Agreement under the Spinnaker Exploration Company 2001 Stock Incentive Plan (filed with the Commission on May 12, 2005 as Exhibit 10.3 to our current report on Form 8-K dated May 6, 2005 and incorporated herein by reference)
10.8	Spinnaker Exploration Company Executive Change in Control Severance Plan (filed with the Commission on June 3, 2005 as Exhibit 10.1 to our current report on Form 8-K dated May 31, 2005 and incorporated herein by reference)
10.9	Spinnaker Exploration Company Employee Change in Control Severance Plan (filed with the Commission on June 3, 2005 as Exhibit 10.2 to our current report on Form 8-K dated May 31, 2005 and incorporated herein by reference)
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