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n 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. Spinnaker uses the expected cash flow approach for calculating asset retirement obligations. The liability is discounted using the credit-adjusted risk-free interest rate in effect when the liability is initially recognized. The changes in the liability for an asset retirement obligation due to the passage of time are measured by applying an interest method of allocation to the amount of the liability at the beginning of the period. This amount is recognized as an increase in the carrying amount of the liability and as accretion expense classified as an operating item in the statement of operations.

Financial Instruments and Price Risk Management Activities

As of March 31, 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. We recorded net hedging income of $0.6 million and $1.7 million in the first quarter of 2005 and 2004, respectively.

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, 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 quarter 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 quarter 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 quarter 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.

Results of Operations

	Three Months Ended March 31,			
	2005	**2004**	**Variance**	
Production:				
Natural gas (MMcf)	6,702	7,816	(1,114)	(14)%
Oil and condensate (MBbls)	693	332	361	109%
Natural gas liquids (thousands of Gallons)	6,668	3,412	3,256	95%
Total (MMcfe)	11,811	10,295	1,516	15%
Revenues (in thousands):				
Natural gas	$ 42,617	$ 44,198	$ (1,581)	(4)%
Oil and condensate	32,391	11,547	20,844	181%
Natural gas liquids	4,282	2,024	2,258	112%
Net hedging income (loss)	593	1,739	(1,146)	(66)%
Other	(1,560)	283	(1,843)	(651)%

Total	$ 78,323	$ 59,791	$ 18,532	31%
Average realized sales price per unit:				
Natural gas revenues from production (per Mcf)	$ 6.36	$ 5.65	$ 0.71	13%
Effects of hedging activities (per Mcf)	0.40	0.22	0.18	82%
Average realized price (per Mcf)	$ 6.76	$ 5.87	$ 0.89	15%
Oil and condensate revenues from production (per Bbl)	$ 46.76	$ 34.79	$ 11.97	34%
Effects of hedging activities (per Bbl)	(3.03)		(3.03)	
Average realized price (per Bbl)	$ 43.73	$ 34.79	$ 8.94	26%
Natural gas liquids revenues from production (per Gallon)	$ 0.64	$ 0.59	$ 0.05	8%
Effects of hedging activities (per Gallon)				
Average realized price (per Gallon)	$ 0.64	$ 0.59	$ 0.05	8%
Total revenues from production (per Mcfe)	$ 6.71	$ 5.61	$ 1.10	20%
Effects of hedging activities (per Mcfe)	0.05	0.17	(0.12)	(71)%
Total average realized price (per Mcfe)	$ 6.76	$ 5.78	$ 0.98	17%
Expenses (per Mcfe):				
Lease operating expenses	$ 0.56	$ 0.46	$ 0.10	22%
Depreciation, depletion and amortization oil and gas properties oil and gas properties	$ 3.51	$ 2.82	$ 0.69	24%

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Three Months Ended March 31, 2005 as Compared to the Three Months Ended March 31, 2004

Revenues and Production

Revenues increased $18.5 million, or 31%, in the first quarter of 2005 compared to the first quarter of 2004. The increase was primarily due to 15% higher production and a 20% higher average commodity price in the first quarter of 2005, partially offset by a $1.1 million decrease in hedging gains and a $1.8 million net decrease in other revenues resulting primarily from the ineffective component of derivatives of $1.7 million.

Production increased approximately 1.5 Bcfe, or 15%, in the first quarter of 2005 compared to the first quarter of 2004 primarily due to Front Runner oil production. Front Runner commenced production in December 2004 from the first of nine wells. One additional well was completed and commenced production in the first quarter and another well was completed and commenced production subsequent to March 31, 2005. Six additional wells will be completed at the Front Runner spar production facility. Average daily production in the first quarter of 2005 was 131 MMcfe compared to 113 MMcfe in the first quarter of 2004. Natural gas revenues decreased $1.6 million, or 4%, due primarily to lower production of 1.1 Bcf, or 14%, partially offset by a 13% higher average price in the first quarter of 2005. Excluding the effects of hedging activities, the first quarter 2005 average natural gas price was $6.36 per Mcf compared to $5.65 per Mcf in the same period of 2004. Oil and condensate revenues increased $20.8 million, or 181%, due primarily to an increase in production of 361 MBbls, or 109%, and a 34% higher average price. Excluding the effects of hedging activities, the first quarter 2005 average oil price was $46.76 per barrel compared to $34.79 per barrel in the same period of 2004. Natural gas liquids revenues increased $2.3 million, or 112%, in the first 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 $1.9 million, or 41%, in the first quarter of 2005 compared to the same period in 2004. Of the total increase, approximately $1.1 million was related to lease operating expenses at Front Runner, our deepwater project that commenced production in December 2004, and $1.3 million related to lease operating expenses on other blocks where production commenced during and subsequent to the first quarter of 2004, offset in part by a net $0.5 million decrease in costs associated with producing wells as of March 31, 2004.

Depreciation, Depletion and Amortization

DD&A increased $12.4 million, or 43%, in the first quarter of 2005 compared to the first quarter of 2004. Of the total increase in DD&A, $8.1 million related to a higher DD&A rate and $4.3 million related to higher production of 1.5 Bcfe. The 24% increase in the DD&A rate per Mcfe to $3.51 in the first quarter of 2005 from $2.82 in the same period in 2004 was primarily due to costs associated with unsuccessful wells in 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 Unproved Properties

Based on information available subsequent to March 31, 2005 that indicated unproved international oil and gas properties were impaired, we recorded a $7.7 million impairment charge 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 increased $0.6 million, or 17%, in the first quarter of 2005 compared to the first quarter of 2004. The increase was primarily due to higher employment-related expenses, legal fees and costs associated with Sarbanes-Oxley Section 404 compliance.

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Income Tax Expense

Income tax expense decreased $1.6 million, or 20%, due to lower pre-tax income and a reduction in the effective tax rate to 35.3% in the first quarter of 2005 from 36.0% in the first quarter of 2004. The effective tax rate was reduced to 35.3% 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. Net additions to property and equipment in the first quarter of 2005 were $91.4 million. We have capital expenditure plans for 2005 totaling approximately $294.0 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 for the first time since our inception. However, 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, proceeds from available borrowings under the Revolver and Front Runner spar production facility financing opportunities will be sufficient to meet our capital requirements in the next twelve months. However, additional debt or equity financing may be required in the future to fund growth and 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 March 31, 2005, we had outstanding borrowings of $105.0 million and were in compliance with provisions of the Revolver. Subsequent to March 31, 2005, we had additional borrowings of $7.5 million and made payments of $12.5 million. We expect to incur additional borrowings in 2005. See *Financing Activities* for more information.

Spinnaker has an effective shelf registration statement relating to the potential public offer and sale by us or certain of our affiliates of up to $500.0 million of any combination of debt securities, preferred stock, common stock, warrants, stock purchase contracts and trust preferred securities from time to time or when financing needs arise. The registration statement does not provide assurance that we will or could sell any such securities.

Contractual Obligations

In the ordinary course of business, we enter into purchase obligations and contracts. As part of our project-oriented exploration and production activities, we routinely enter into these contracts for certain aspects of a project, such as engineering, drilling, subsea work and other equipment and services. We also lease administrative offices, office equipment and oil and gas equipment under non-cancelable operating leases. We had no capital lease or purchase obligations or other contractual long-term liabilities as of March 31, 2005, except for obligations incurred in the ordinary course of business.

As of March 31, 2005, we had borrowings of $105.0 million outstanding under Tranche A of the Revolver, which are due on December 19, 2006. Subsequent to March 31, 2005, Spinnaker had additional borrowings of $7.5 million and made payments of $12.5 million under the Revolver.

Components of Cash Flow

Cash and cash equivalents decreased $7.4 million to $14.4 million as of March 31, 2005. The components of the decrease in cash and cash equivalents included $62.5 million provided by operating activities, $70.5 million used in investing activities and $0.6 million provided by financing activities.

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Operating Activities

Net cash provided by operating activities in the first quarter of 2005 increased 32% to $62.5 million primarily due to higher production and 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 March 31, 2005, Spinnaker had negative working capital of $3.4 million. Excluding current deferred tax assets of $38.7 million, we had negative working capital $42.1 million as of March 31, 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 $1.8 million in accounts receivable since December 31, 2004 was primarily related to a $1.9 million increase in oil and gas revenues receivable, offset in part by a net $0.1 million decrease in joint interest billings and other. Oil and gas revenues receivable increased primarily due to higher oil prices in March 2005 compared to December 2004. 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. Accounts payable and accrued liabilities increased $2.1 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 $70.5 million in the first quarter of 2005 and included oil and gas property expenditures of $70.2 million and purchases of other property and equipment of $0.3 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 March 31, 2005, we have drilled 33 deepwater wells, 22 of which were successful. We currently plan to drill and evaluate several additional deepwater wells in the Gulf of Mexico and one deepwater well in West Africa in the remainder of 2005.

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 a $7.7 million pre-tax impairment charge related to unproved international oil and gas properties in the first quarter of 2005. We will record an additional impairment charge of approximately $0.5 million in the second quarter of 2005 related to well costs incurred subsequent to March 31, 2005. 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 three successful wells in three attempts in the first quarter of 2005. We drilled 27 wells in 2004, 14 of which were successful. Since inception and through March 31, 2005, we drilled 179 wells, 107 of which were successful, representing a success rate of 59%. Dry hole costs, including associated leasehold costs, were approximately $2.2 million in the first quarter of 2005 and primarily related to costs incurred in 2005 on unsuccessful wells in progress as of December 31, 2004 and cost adjustments to prior year unsuccessful wells. Our current capital expenditure budget for 2005 is approximately $294.0 million, including $201.0 million for exploration activities and geological and geophysical expenditures, $50.0 million for development activities, $40.0 million for leasehold acquisitions and $3.0 million for other property and equipment. We currently plan to drill and evaluate 20 wells in the remainder of 2005, including 13 wells on the Gulf of Mexico shelf, six wells in the deep water of the Gulf of Mexico and one additional 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 $0.5 million in the first quarter of 2005. Current liabilities include asset retirement obligations of $8.1 million, the settlements of which will depend on the timing of abandonment decisions and equipment availability in 2005.

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The costs associated with unproved properties and properties under development not included in the amortization base were as follows (in thousands):

	As of March 31, 2005	As of December 31, 2004
Leasehold, delay rentals and seismic data, hardware and software costs	$ 157,094	$ 128,465
Wells in-progress	18,548	3,836
Wells pending determination	15,492	14,820
Other	1,205	1,156
Total	$ 192,339	$ 148,277

Financing Activities

Net cash provided by financing activities of $0.6 million in the first quarter of 2005 related to proceeds from stock option exercises.

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. Borrowings under each tranche 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 March 31, 2005. Tranche B is $50.0 million, is available in multiple advances through October 31, 2005 and is not subject to the borrowing base. Borrowings under Tranche B cannot be reborrowed once repaid. Total availability under Tranche A and Tranche B cannot exceed $200.0 million. When the borrowing base exceeds $150.0 million, Tranche B is reduced by a like amount for the period the borrowing base exceeds $150.0 million until the maturity of Tranche B. The obligations under Tranche A are unsecured. At such time Tranche B is utilized, the banks are to be provided with security interests in virtually all of our reserve base. Upon repayment of Tranche B, the security interests are to be released.

The borrowing base is re-determined semi-annually by the banks in their sole discretion and in their usual and customary manner. 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, or $10.0 million when Tranche B is utilized.

We have the option to elect to use a base interest rate as described below or 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% for Tranche A borrowings and from 2.0% to 2.75% for Tranche B borrowings. The LIBOR spread ranges from 1.25% to 2.0% for Tranche A borrowings and from 3.0% to 3.75% for Tranche B borrowings. The base interest rate under the Revolver is a fluctuating rate of interest equal to the 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 4.32% in the first quarter of 2005. The commitment fee rate ranges from 0.375% to 0.5%, depending on the borrowing base usage for Tranche A, and is 0.625% for Tranche B.

The Revolver also includes the following restrictions and covenants:

Incurrence of other debt is prohibited except that senior debt may not exceed $10.0 million ($5.0 million when Tranche B is used), vendor indebtedness for the purchase of seismic data may not exceed $25.0 million, subordinated debt is permitted subject to certain conditions and a lease transaction involving the Front Runner spar production facility is specifically permitted.

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Liens are generally prohibited; however, we may grant a lien in connection with the purchase of seismic data, 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.

On March 29, 2005, Spinnaker Exploration Company, L.L.C. and the banks entered into a second amendment to the Revolver. Among other provisions, the amendment extended the Tranche B termination date to October 31, 2005, unless sooner terminated in accordance with the Revolver.

As of March 31, 2005, we had outstanding borrowings of $105.0 million. Current availability is $55.0 million and $40.0 million under Tranche A and Tranche B, respectively. As of March 31, 2005, we were in compliance with the provisions of the Revolver. Subsequent to March 31, 2005, we had additional borrowings of $7.5 million and made payments of $12.5 million under 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

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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.

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 March 31, 2005, our commodity price risk management positions in swap contracts and collar arrangements were as follows:

Natural Gas

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

Oil

	Fixed Price Swaps		Collars		
Period	Average Daily Volume (Bbls)	Weighted Average Price (Per Bbl)	Average Daily Volume (Bbls)	Weighted Average Price (Per Bbl) Floor	Ceiling

Second Quarter 2005	1,000	$ 40.78	3,000	$ 38.67	$ 44.73
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 $17.6 million and a net asset of $1.2 million related to financial derivative contracts as of March 31, 2005 and December 31, 2004, respectively. Amounts related to hedging activities were as follows (in thousands):

	As of March 31, 2005	**As of December 31, 2004**
Current assets:		
Hedging assets	$	$ 2,829
Deferred tax asset related to hedging activities	6,203	
Current liabilities:		
Hedging liabilities	$ 17,571	$ 1,628
Deferred tax liability related to hedging activities		432
Equity:		
Accumulated other comprehensive income (loss)	$ (10,281)	$ 963

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The ineffective component of the derivatives and net hedging gains (losses) were recorded in revenues in the three months ended March 31, 2005 and 2004 as follows (in thousands):

	Three Months Ended March 31,	
	2005	2004
Ineffective component of derivatives	$ (1,682)	$
Net hedging income	$ 593	$ 1,739

Based on future oil and gas prices as of March 31, 2005, we would reclassify a net loss of approximately $10.3 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 March 31, 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 Decrease in Revenues with 10% Decrease in Prices	Estimated Decrease in Revenues with 10% Increase in Prices
Natural gas swaps	$ (2,885)	$ (2,780)	$ (4,101)
Oil swaps	(4,578)	(3,356)	(7,080)
Oil collars	(10,108)	(6,432)	(15,949)

Subsequent to March 31, 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 $52.81 and $6.77, respectively, as of May 6, 2005 was a net liability of approximately $9.7 million, excluding April and May 2005 settlements resulting in losses of $1.5 million. We did not enter into any additional derivative transactions subsequent to March 31, 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.

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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 March 31, 2005.

Changes in Internal Control Over Financial Reporting

During the three months ended March 31, 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.

PART II - OTHER INFORMATION

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: May 9, 2005

By: /s/ ROBERT M. SNELL

Robert M. Snell

Vice President, Chief Financial

Officer and Secretary

Date: May 9, 2005

By: /s/ JEFFREY C. ZARUBA

Jeffrey C. Zaruba

Vice President, Treasurer and

Assistant Secretary

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EXHIBIT INDEX

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