NEWFIELD EXPLORATION CO /DE/
Form 10-K/A
August 09, 2004

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549
Amendment No. 1
to

Form 10-K/A

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2003

or

o **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: 1-12534

Newfield Exploration Company

(Exact name of registrant as specified in its charter)

Delaware	**72-1133047**
(State of incorporation)	*(I.R.S. Employer Identification No.)*
363 North Sam Houston Parkway East, Suite 2020, Houston, Texas	**77060**
(Address of principal executive offices)	*(Zip Code)*

Registrant s telephone number, including area code:

281-847-6000

Securities registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	New York Stock Exchange
Rights to Purchase Series A Junior Participating Preferred Stock, par value $0.01 per share	New York Stock Exchange

Securities registered Pursuant to Section 12(g) of the Act:

None

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 þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was approximately $1,843,394,000 as of June 30, 2003 (based on the last sale price of such stock as quoted on the New York Stock Exchange).

As of March 10, 2004, there were 56,335,235 shares of the registrant s common stock, par value $0.01 per share, outstanding.

Documents incorporated by reference: Proxy Statement of Newfield Exploration Company for the Annual Meeting of Stockholders to be held May 6, 2004, which is incorporated by reference into Part III of this Form 10-K.

EXPLANATORY NOTE

We are filing this amendment to our annual report for the year ended December 31, 2003 to respond to comments received by us from the Staff of the Securities and Exchange Commission in connection with its review of our annual report for the year ended December 31, 2003. Our consolidated financial position and consolidated results of operations for the periods presented have not been restated from the consolidated financial position and consolidated results of operations originally reported; however, we have reclassified $15.1 million within current assets from the caption Assets of discontinued operations to Cash and cash equivalents on our consolidated balance sheet.

For convenience and ease of reference we are filing our annual report in its entirety with the applicable changes. Unless otherwise stated, all information contained in this amended report is as of March 15, 2004, the original filing date of our annual report for the year ended December 31, 2003.

TABLE OF CONTENTS

Unless the context otherwise requires, all references in this report to Newfield, we, us or our are to Newfield Exploration Company and its subsidiaries. Unless otherwise noted, all information in this report relating to oil and gas reserves and the estimated future net cash flows attributable to those reserves are based on estimates we prepared and are net to our interest. If you are not familiar with the oil and gas terms used in this report, please refer to the explanations of such terms under the caption Commonly Used Oil and Gas Terms at the end of Item 7 of this report.

PART I

Item 1. *Business*

We are an independent oil and gas company engaged in the exploration, development and acquisition of crude oil and natural gas properties. Our company was founded in 1989. Our initial focus area was the Gulf of Mexico. In the mid-1990s, we began to expand our operations to other select areas. Our areas of operation now include the Gulf of Mexico, the U.S. onshore Gulf Coast, the Anadarko and Arkoma Basins, China s Bohai Bay and the North Sea. Over the last three years, we have acquired significant onshore assets. Today, more than half of our reserves are located onshore in the U.S.

General information about us can be found at *www.newfld.com.* Our Annual Report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our website as soon as reasonably practicable after we file or furnish them to the SEC.

At year-end 2003, we had proved reserves of 1.32 Tcfe. Of those reserves:

- 83% were natural gas;
- 87% were proved developed;
- 41% were located in the Gulf of Mexico; and
- 59% were located onshore in the U.S.

Strategy

The elements of our growth strategy have remained substantially unchanged since our founding and consist of:

- balancing our efforts among exploration, the acquisition of proved reserves and the development of proved properties;
- growing reserves through the drilling of a balanced risk/reward portfolio;
- focusing on select geographic areas;
- controlling operations and costs;
- using 3-D seismic data and other advanced technologies; and
- attracting and retaining a quality workforce through equity ownership and other performance-based incentives.

Balance. We actively pursue the acquisition of proved oil and gas properties in our existing focus areas and other select geographic areas. The potential to add reserves through the drillbit is a critical consideration in our acquisition screening process. Each year we invest a significant portion of our capital budget in exploration. Over the last three years, the amount of funds dedicated to exploration spending has increased significantly. We actively look for new drilling ideas on our existing property base and on properties that may be acquired at federal lease sales or by farm-in. Large acquisitions over the last few years, recent drilling success and our growing onshore acreage positions provide us with significant drilling opportunities.

1

Drilling Program. The reserves targeted by our drilling program are distributed throughout the risk/reward spectrum. In an effort to manage the risks associated with our strategy to grow our reserves through the drillbit, each year we drill a greater number of lower risk, low to moderate potential prospects and a lesser number of higher risk, higher potential prospects. Our traditional shelf plays and low-risk drilling opportunities in the Mid-Continent are complemented with two higher potential plays in the Gulf of Mexico the deep shelf and deepwater. We may also increase our exposure to high potential prospects through the addition of new focus areas overseas.

Geographic Focus. We believe that our long-term success requires extensive knowledge of the geologic and operating conditions in the areas where we operate. Because of this belief, we focus our efforts on a limited number of geographic areas where we can use our core competencies and have a significant influence on operations. We also believe that geographic focus allows us to make the most efficient use of our capital and personnel.

Control of Operations and Costs. In general, we prefer to operate our properties. By controlling operations, we can better manage production performance, control operating expenses and capital expenditures, consider the application of technologies and influence timing. At the end of 2003, we operated about 72% of our total production.

Technology. By investing in technology, we give our people the tools they need to succeed. Over the last five years, we have invested about $115 million in the acquisition of new seismic data. This significant expenditure is related primarily to the onshore Gulf Coast and the deepwater Gulf of Mexico. At February 29, 2004, we held licenses or otherwise had access to 3-D seismic surveys covering approximately 5,100 blocks (about 25 million acres) in the Gulf of Mexico s shallow waters, 1,450 blocks in the deepwater Gulf of Mexico, 5,600 square miles onshore Texas and Louisiana, 3,300 square miles in the Anadarko Basin, 400 square kilometers covering the area where we are active offshore China and 19,100 square kilometers in the Southern Gas Basin of the North Sea.

Equity Ownership and Incentive Compensation. We want our employees to act like owners. To achieve this, we reward and encourage them through equity ownership and incentive compensation based on performance and profitability. A significant portion of our employees compensation is discretionary and performance-based. As of February 29, 2004, our employees owned or had options to acquire about 8% of our outstanding common stock on a fully diluted basis.

Focus Areas

Gulf of Mexico. We have extensive experience in the Gulf of Mexico and it is where we continue to invest the largest portion of our capital program. The shallow water Gulf has substantial existing infrastructure, including gathering systems, platforms and pipelines, facilitating cost effective operations and timely development of discoveries. Although the traditional shelf plays in the Gulf of Mexico are mature, we believe that significant opportunities remain in deep shelf and deepwater plays. As a result, we are allocating a larger portion of our budget to these plays. We also are evaluating a concept we refer to as Treasure Project. The ultra-deep targets of this concept are high risk but the potential reserve impact could be significant.

Traditional Shelf. We consider the traditional shelf generally to be horizons at depths of less than 13,000-15,000 feet located in water depths of generally less than 1,000 feet. We operate about 150 production platforms and utilize this infrastructure to our advantage. Although prospects in the traditional shelf usually offer modest reserve potential, the associated risks generally are lower.

Deep Shelf. We are exploring deeper horizons on the shelf with recent wells drilled to depths of 15,000-20,000 feet. We have drilled twelve successful deep shelf wells out of 17 attempts to date. The risk profile of these wells is significantly different than our traditional shelf drilling. These deeper targets are more difficult to detect with traditional seismic processing and the cost to drill and the risk of mechanical failure are likely to be significantly higher because of the drilling depth and high temperature and pressure. These prospects have dryhole costs of $8-15 million per well.

Treasure Project. Through our acquisition of EEX, we gained an interest in 26 blocks associated with an ultra-deep drilling concept in shallow water known as Treasure Island. Since the acquisition, the geographic scope of this concept has been significantly expanded and we now own an interest in 80 lease blocks associated with it. We now refer to the entire concept, wherever located within the shallow waters of the Gulf, as Treasure Project. This high-risk, high potential concept has targeted depths of 25,000 feet or more. There is no production from these depths on the Gulf of Mexico shelf today. We are evaluating this concept and seeking partners to carry all, or a substantial portion of, the drilling cost on one or more wells. Dry hole costs are expected to range from $35-70 million per well.

Deepwater. We established a deepwater team in 2001 and made our first deepwater discovery in 2003. The risks associated with deepwater operations can be significantly greater than traditional shelf operations. Drilling and development costs may be materially higher and lead times to first production may be much longer. We are focusing on projects nearer to infrastructure and in water depths where development technology is proven. As our knowledge and experience base advances, we will consider moving into deeper waters, toward larger targets and into more remote regions where infrastructure may not exist. We now own an interest in about 85 deepwater lease blocks in the Gulf of Mexico. We also have made some personnel additions to give us additional expertise in this new effort.

Onshore Gulf Coast. We established onshore Gulf Coast operations in 1995 and made major acquisitions in 2000 and 2002 to grow our presence. Today, the onshore Gulf Coast is a major focus area for us, representing about one-third of our total proved reserves and daily production. Our operations are concentrated in South Texas, the Val Verde Basin in southwest Texas, East Texas and southern Louisiana. We continue to screen for attractive acquisitions to further expand this focus area.

Mid-Continent. Through an acquisition in January 2001, we added the Mid-Continent as a focus area. We have continued to build our land position and production in this region through leasing efforts and acquisitions. About 90% of our proved reserves in the Mid-Continent are located in the Anadarko Basin of Oklahoma. These assets are typically longer-lived and offset our shorter reserve life properties in the Gulf Coast region. We believe that the Mid-Continent provides an opportunity for future growth. It is a gas-rich province characterized by multiple productive zones and relatively low drilling costs. Recent efforts have focused on a new initiative that we call gas mining. Through this initiative, we have identified low risk, marginal resource areas that have been under-exploited. Keys to success include scale, repeatability and lowering of finding costs through drilling and completion innovations. Our Mid-Continent assets are managed by our Tulsa, Oklahoma office.

International. In the mid-1990s, we began to consider investment in select international areas to provide additional or alternative opportunities and to gain exposure to high potential prospects. We currently own an interest in two undeveloped fields in China s Bohai Bay. In 2002, we opened an office in London, England, to pursue opportunities in the North Sea. We acquired an interest in one producing field and one undeveloped discovery in the North Sea in December 2003. We expect to drill our first well in the region in the second half of 2004 on a license block awarded in 2003. We also hold two lease blocks offshore Brazil. We continue to evaluate and pursue other opportunities for expansion in select international areas. In September 2003, we sold all of our operations in Australia.

Plans for 2004

Our capital budget for 2004 is $600 million, excluding acquisitions. We expect that about half of the budget will be invested in the Gulf of Mexico (including deepwater), 35-40% in the onshore U.S. and the remainder in international projects. We plan to drill about 250 wells in 2004, over half of which are expected to be in the Mid-Continent.

Gulf of Mexico. We plan to remain an active driller in the traditional shallow water plays of the Gulf of Mexico. About half of our 2004 capital budget is allocated to the Gulf of Mexico, where we expect to drill 25-35 wells. In addition to 15-20 wells in the traditional shelf, we expect to drill six to eight wells in the deep shelf and three to five wells in deepwater.

Onshore Gulf Coast. In 2004, we will balance development drilling of lower risk opportunities with some higher risk, higher impact exploration tests. We plan to drill 50-60 wells.

Mid-Continent. Our Mid-Continent drilling program is predominantly comprised of lower risk exploitation wells. In 2004, we expect to drill about 160 wells. The majority of the planned drilling is associated with our gas mining initiative.

International. In the second half of 2004, we expect to drill a well on our Cumbria Prospect, located on license area 49/4b in the Southern Gas Basin of the North Sea. In China s Bohai Bay, the operator of our two undeveloped fields is in the process of filing development plans with the Chinese government during 2004 and field development will begin following government approval.

Marketing

We market nearly all of our oil and gas production from the properties we operate for both our account and the account of the other working interest owners in these properties. Substantially all of our natural gas production is sold to a variety of purchasers under short-term (less than 12 months) contracts at current market prices. Oil sales contracts are short-term and are based upon posted prices plus negotiated bonuses. For a list of purchasers of our oil and gas production that accounted for 10% or more of consolidated revenue for the three preceding calendar years, please see Note 1, Organization and Summary of Significant Accounting Policies *Major Customers*, to our consolidated financial statements. Because alternative purchasers of oil and gas are readily available, we believe that the loss of any of these purchasers would not have a material adverse effect on us.

Competition

Competition in the oil and gas industry is intense, particularly with respect to the acquisition of producing properties and proved undeveloped acreage. For a further discussion of this competitive environment, please see the information set forth under the caption Other Factors Affecting Our Business and Financial Results in Item 7 of this report.

Employees

As of March 1, 2004, we had about 375 employees. All but five of our employees are located in the U.S. We believe that relationships with our employees are satisfactory. None of our employees is covered by a collective bargaining agreement.

We regularly utilize independent consultants and contractors to perform various professional services, particularly in the areas of acquisition evaluation, construction, design, well site surveillance, permitting and environmental assessment. U.S. offshore field and on-site production operation services, such as pumping, maintenance, dispatching, inspection and testing, are generally provided by independent contractors.

Regulation and Other Factors Affecting Our Business and Financial Results

For a discussion of the significant governmental regulations to which our business is subject and other significant factors that may affect our business, please see the information set forth under the captions Regulation and Other Factors Affecting Our Business and Financial Results in Item 7 of this report.

Item 2. ***Properties***
Concentration

We have diversified our asset base over the last several years. About 41% of our proved reserves are now located in the Gulf of Mexico compared to about 94% just five years ago. In total, 74% of our proved reserves are located in the Gulf of Mexico and along the onshore regions of the Gulf Coast. While our ten largest properties accounted for approximately 30% of our equivalent proved reserves at year-end 2003, no single

4

property held more than 5% of our proved reserves or more than 3% of the net present value of our proved reserves.

Gulf of Mexico

Our properties are in water depths ranging from 45 to more than 6,000 feet. As of December 31, 2003, we owned interests in about 250 leases on the Shelf and 85 leases in deepwater (approximately 1.7 million gross acres) and about 330 gross wells. We operated 79% of our proved reserves at December 31, 2003.

Onshore Gulf Coast

We have a significant acreage position in Texas and Louisiana. As of December 31, 2003, we owned an interest in about 290,000 gross acres and more than 400 gross wells. We operated 71% of our proved reserves at December 31, 2003.

Mid-Continent

We have a sizeable presence in the Anadarko and Arkoma Basins, established with an acquisition in early 2001. Since that time, we have added to our acreage position through subsequent acquisitions and leasing efforts. As of December 31, 2003, we owned an interest in approximately 614,000 gross lease acres, 21,700 gross mineral acres and 1,700 gross wells. We operated 81% of our proved reserves at December 31, 2003.

International

China. We own a 35% interest in a license area located in Block 05/36 in Bohai Bay, offshore China. Our interest is subject to a 51% reversionary interest held by the Chinese National Offshore Oil Company. The license area covers more than 230,000 gross acres. There currently is no production on the block. Since 2000, we have discovered two fields on the block the CFD 12-1 and the CFD 12-1 South. Four appraisal wells were drilled in the fields in 2003 and we now believe that commercial oil reserves exist. The operator is in the process of filing a development plan with the Chinese government. If the plan is approved, we will begin field development. We have not booked any proved reserves on these fields to date.

North Sea. In 2003, we acquired an interest in one producing field and one undeveloped discovery in the North Sea. We expect to drill our first well in the region in the second half of 2004 on a license block awarded in 2003.

Proved Reserves and Future Net Cash Flows

The following table shows our estimated net proved oil and gas reserves and the present value of estimated future after-tax net cash flows related to such reserves as of December 31, 2003. The present value of estimated future after-tax net cash flows was prepared using year-end oil and gas prices adjusted for the location and quality of the reserves, discounted at 10% per year. Application of year-end prices, as adjusted for location and quality, resulted in weighted average year-end prices of $5.93 per Mcf for gas and $30.79 per Bbl for oil. This calculation does not include the effects of hedging.

	Proved Reserves		
	Developed	**Undeveloped**	**Total**
United States:			
Oil and condensate (MBbls)	30,688	7,060	37,748
Gas (MMcf)	955,760	131,908	1,087,668
Total proved reserves (MMcfe)	1,139,893	174,265	1,314,158
Present value of estimated future after-tax net cash flows (in thousands)[1]			$2,932,768
United Kingdom:			
Oil and condensate (MBbls)	26		26
Gas (MMcf)	2,472		2,472
Total proved reserves (MMcfe)	2,628		2,628
Present value of estimated future after-tax net cash flows (in thousands)[1]			$ 2,671
Total:			
Oil and condensate (MBbls)	30,714	7,060	37,774
Gas (MMcf)	958,232	131,908	1,090,140
Total proved reserves (MMcfe)	1,142,521	174,265	1,316,786
Present value of estimated future after-tax net cash flows (in thousands)[1]			$2,935,439

(1) For a description of how this measure is determined, see Unaudited Supplementary Oil and Gas Disclosures Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves.

All reserve information in this report is based on estimates prepared by our petroleum engineering staff. As a requirement of our revolving credit facility, independent reserve engineers prepare separate reserve reports with respect to properties holding at least 80% of our proved reserves. For December 31, 2003, the independent reserve engineers reports covered properties representing 83% of our proved reserves and for such properties, the reserves were within 3% of the reserves we reported for such properties. Actual quantities of recoverable oil and gas reserves and future cash flows from those reserves most likely will vary from the estimates set forth above. Reserve and cash flow estimates rely on interpretations of data and require many assumptions that may turn out to be inaccurate. For a discussion of these interpretations and assumptions, see Other Factors Affecting Our Business and Financial Results and Forward Looking Statements under Item 7 of this report.

As an operator of domestic oil and gas properties, we file Department of Energy Form EIA-23, Annual Survey of Oil and Gas Reserves, as required by Public Law 93-275. There are differences between the reserves as reported on Form EIA-23 and as reported above. The differences are attributable to the fact that Form EIA-23 requires that an operator report on the total reserves attributable to wells that are operated by it, without regard to ownership (i.e., reserves are reported on a gross operated basis, rather than on a net interest basis).

Reserve Replacement Cost

The table below provides information regarding the costs we incurred for oil and gas property acquisition, exploration and development activities for the year ended December 31, 2003 and the proved reserves we added during that period.

	Costs Incurred[1]	Reserves Added[2]	Average Replacement Cost[3]
	(In thousands)	(MMcfe)	(Per Mcfe)
United States:			
Acquisitions	$175,724	118,365	$ 1.48
Drilling	455,096	237,731	1.91
Total	630,820	356,096	1.77
International:			
Acquisitions	9,065	2,673	3.39
Drilling[4]	6,863		N/M(5)
Total	15,928	2,673	5.96
Total:			
Acquisitions	184,789	121,038	1.53
Drilling	461,959	237,731	1.94
Total	$646,748	358,769	$ 1.80

(1) Excludes capitalized asset retirement costs of $132.3 million recorded in compliance with SFAS No. 143, Accounting for Asset Retirement Obligations, adopted on January 1, 2003. See the unaudited supplementary oil and gas disclosures to our consolidated financial statements.

(2) Includes extensions, discoveries and other additions, revisions of previous estimates and purchases of properties but excludes sales of properties. See the unaudited supplementary oil and gas disclosures to our consolidated financial statements.

(3) Costs incurred divided by reserves added.

(4) Includes $5.0 million of costs associated with our exploration efforts offshore China.

(5) Not meaningful.

Drilling Activity

The following table sets forth our drilling activity (other than drilling activity related to our discontinued operations in Australia) for each year in the three-year period ended December 31, 2003.

	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Productive U.S.	27	16.1	23	14.3	31	21.0
Nonproductive U.S.	24	14.4	13	7.8	13	8.8
Productive China[1]						
Nonproductive China	1	0.4	1	0.4	1	0.4
Total	52	30.9	37	22.5	45	30.2
Development wells:						
Productive U.S.	139	92.4	36	18.0	81	50.2
Nonproductive U.S.	6	2.8	7	4.4	11	6.5
Total	145	95.2	43	22.4	92	56.7

(1) We drilled two gross (0.70 net), one gross (0.35 net) and four gross (1.4 net) appraisal wells in China during 2003, 2002 and 2001, respectively, that are not included in the table because the commerciality of these wells had not been determined as of December 31, 2003.

We were in the process of drilling one gross (1.0 net) exploratory well and 16 gross (14.2 net) development wells at December 31, 2003, all of which are in the U.S.

Productive Wells

The following table sets forth the number of productive oil and gas wells in which we owned an interest as of December 31, 2003 and the location of, and other information with respect to, those wells.

	Company Operated Wells		Outside Operated Wells		Total Productive Wells	
	Gross	Net	Gross	Net	Gross	Net
United States:						
Gulf of Mexico:						
Oil	67	47.6	9	2.1	76	49.7
Gas	144	100.8	77	20.0	221	120.8
Louisiana:						
Oil	1	0.8	2	0.2	3	1.0
Gas	3	1.2	10	3.1	13	4.3
Texas:						
Oil	22	17.4	34	4.3	56	21.7
Gas	307	272.9	252	107.6	559	380.5
Oklahoma:						
Oil	279	190.0	608	22.7	887	212.7
Gas	405	275.8	419	65.3	824	341.1
Other domestic:						
Oil	3	2.0	1	0.3	4	2.3
Gas	12	8.6	23	3.8	35	12.4
Total domestic:						
Oil	372	257.8	654	29.6	1,026	287.4
Gas	871	659.3	781	199.8	1,652	859.1
International:						
Offshore United Kingdom:						
Gas			2	0.4	2	0.4
Total:						
Oil	372	257.8	654	29.6	1,026	287.4
Gas	871	659.3	783	200.2	1,654	859.5
Total	1,243	917.1	1,437	229.8	2,680	1,146.9

The day-to-day operations of oil and gas properties are the responsibility of an operator designated under pooling or operating agreements. The operator supervises production, maintains production records, employs or contracts for field personnel and performs other functions. An operator receives reimbursement for direct expenses incurred in the performance of its duties as well as monthly per-well producing and drilling overhead reimbursement at rates customarily charged by unaffiliated third parties. The charges customarily vary with the depth and location of the well being operated.

Acreage Data

We own interests in developed and undeveloped oil and gas acreage in the locations set forth in the table below. These ownership interests generally take the form of working interests in oil and gas leases or licenses that have varying terms. The following table shows certain information regarding our developed and undeveloped acreage as of December 31, 2003.

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
United States:				
Gulf of Mexico:				
Shelf	676,143	363,399	203,835	144,095
Treasure Project			413,717	162,559
Deepwater	63,360	17,249	339,840	126,383
Total Gulf of Mexico	739,503	380,648	957,392	433,037
Texas	136,930	73,800	188,417	107,329
Louisiana	10,437	6,191	11,500	4,059
Oklahoma	262,494	131,604	269,390	146,400
Other domestic	14,163	5,882	9,706	4,676
Total onshore	424,024	217,477	479,013	262,464
Total domestic	1,163,527	598,125	1,436,405	695,501
International:				
Offshore China			233,510	81,728
Offshore Brazil			206,253	206,253
Offshore United Kingdom	6,027	1,205	27,096	18,110
Total international	6,027	1,205	466,859	306,091
Total	1,169,554	599,330	1,903,264	1,001,592

On January 1, 2004, our undeveloped acreage position associated with Treasure Project increased by 70,052 net acres as a result of the termination of an agreement with BP Exploration & Production Inc.

The table below summarizes by year and geographic area our undeveloped lease or license acreage scheduled to expire in the next five years. In most cases, the drilling of a commercial well, or the filing and approval of a development plan, will hold acreage beyond the expiration date. We own fee mineral interests in 204,914 gross (80,878 net) undeveloped acres. These interests do not expire.

	Undeveloped Acres Expiring									
	2004		2005		2006		2007		2008	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United States:										
Gulf of Mexico:										
Shelf	10,000	8,333	9,503	7,127	52,690	41,687	53,170	33,277	70,114	56,936
Treasure Project			68,153	16,378	30,195	7,549	30,168	7,542	235,640	108,788
Deepwater	17,280	3,456	92,160	29,203	69,120	32,544	57,600	23,520	11,520	2,957
Total Gulf of Mexico	27,280	11,789	169,816	52,708	152,005	81,780	140,938	64,339	317,274	168,681
Onshore	112,917	65,676	60,724	33,822	73,905	45,006	3,695	3,020	563	563
Total domestic	140,197	77,465	230,540	86,530	225,910	126,786	144,633	67,359	317,837	169,244
International:										
Offshore China	233,510	81,728								
Offshore Brazil							75,265	75,265		
Offshore United Kingdom							12,054	12,054		
Total international	233,510	81,728					87,319	87,319		
Total	373,707	159,193	230,540	86,530	225,910	126,786	231,952	154,678	317,837	169,244

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry in the case of undeveloped properties, often little investigation of record title is made at the time of acquisition. Investigations are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use, or affect the value, of the properties. Burdens on properties may include:

- customary royalty interests;
- liens incident to operating agreements and for current taxes;
- obligations or duties under applicable laws;
- development obligations under oil and gas leases; and
- burdens such as net profits interests.

Item 3. ***Legal Proceedings***

We have been named as a defendant in a number of lawsuits arising in the ordinary course of our business. While the outcome of these lawsuits cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations.

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

There were no matters submitted to a vote of our security holders during the fourth quarter of 2003.

Item 4A. ***Executive Officers of the Registrant***

The following table sets forth the names and ages (as of February 29, 2004) of and positions held by our executive officers. Our executive officers serve at the discretion of our Board of Directors.

Name	Age	Position	Total Years of Service with Newfield
David A. Trice	55	President and Chief Executive Officer and a Director	9
David F. Schaible	43	Vice President Acquisitions and Development and a Director	14
Terry W. Rathert	51	Vice President, Chief Financial Officer and Secretary	14
Elliott Pew	49	Vice President Exploration	6
William D. Schneider	52	Vice President International	14
Brian L. Rickmers	35	Controller and Assistant Secretary	10
Susan G. Riggs	46	Treasurer	7

Each of the executive officers has held the above positions for the past five years, with the exception of the following:

David A. Trice was one of our founders. From 1991 to 1997 he served as President and Chief Executive Officer and a Director of Huffco Group, Inc. He rejoined our company in May 1997 as Vice President Finance and International. He was appointed President and Chief Operating Officer in May 1999 and to his present position on February 1, 2000. He has served as a director since February 2000.

David F. Schaible was elected to our Board of Directors in 2002.

Brian L. Rickmers has served as Controller and Assistant Secretary since May 2001. From February 2000 to May 2001, he served as Assistant Controller. From December 1993, when Mr. Rickmers joined our company, until February 2000, he served as an Accountant and Financial Analyst.

Susan G. Riggs was named to her present position in August 1999. From May 1997, when Ms. Riggs joined our company, to August 1999, she served as a Financial Analyst.

PART II

Item 5. ***Market for Registrant s Common Equity and Related Stockholder Matters***

Our common stock is listed on the New York Stock Exchange under the symbol NFX. The following table sets forth, for each of the periods indicated, the high and low reported sales price of our common stock on the New York Stock Exchange.

	High	Low
2002		
First Quarter	$38.20	$30.34
Second Quarter	39.15	34.10
Third Quarter	37.49	27.16
Fourth Quarter	39.24	31.24
2003		
First Quarter	36.90	31.35
Second Quarter	39.10	32.49
Third Quarter	40.33	33.64
Fourth Quarter	45.51	38.20
2004		
First Quarter (Through March 10, 2004)	50.20	44.15

On March 10, 2004, the last reported sales price of our common stock on the New York Stock Exchange was $46.60 per share.

As of March 10, 2004, there were approximately 2,600 holders of record of our common stock.

We have not paid any cash dividends on our common stock and do not intend to do so in the foreseeable future. We intend to retain earnings for the future operation and development of our business. Any future cash dividends to holders of our common stock would depend on future earnings, capital requirements, our financial condition and other factors determined by our Board of Directors. The covenants contained in our credit facility and in the indenture governing our 8 3/8% Senior Subordinated Notes due 2012 could restrict our ability to pay cash dividends.

Item 6. ***Selected Financial Data***

SELECTED FIVE-YEAR FINANCIAL AND RESERVE DATA

The following table shows selected consolidated financial data derived from our consolidated financial statements and reserve data derived from our supplementary oil and gas disclosures set forth in Item 8 of this report. The data should be read in conjunction with Item 2, *Properties* Proved Reserves and Future Net Cash Flows and Item 7, *Management s Discussion and Analysis of Financial Condition and Results of Operations,* of this report.

	Year Ended December 31,				
	2003	2002	2001	2000	1999
	(In thousands, except per share data)				
Income Statement Data:					
Oil and gas revenues	$1,016,986	$626,835	$714,052	$479,876	$265,603
Operating expenses:					
Lease operating	119,290	90,768	85,683	51,509	38,561
Production and other taxes	31,737	13,285	14,424	5,643	699
Transportation	6,359	5,708	5,569	5,984	5,922
Depreciation, depletion and amortization	394,701	295,054	274,893	183,738	149,350
Ceiling test writedown			106,011	503	
General and administrative(1)	61,636	54,363	42,621	31,473	16,303
Gas sales obligation settlement and redemption of securities	20,475				
Total operating expenses	634,198	459,178	529,201	278,850	210,835
Income from operations	382,788	167,657	184,851	201,026	54,768
Other income (expense), net	(45,067)	(30,535)	(27,592)	(17,583)	(13,590)
Commodity derivative income (expense)(2)	(6,102)	(29,147)	24,821		
Income before income taxes	331,619	107,975	182,080	183,443	41,178
Income tax provision	120,713	39,229	64,726	64,555	14,773
Income from continuing operations	210,906	68,746	117,354	118,888	26,405
Income (loss) from discontinued operations, net of tax(5)	(16,992)	5,101	6,394	15,821	6,799
Income before cumulative effect of change in accounting principle	193,914	73,847	123,748	134,709	33,204
Cumulative effect of change in accounting principle, net of tax(2)(3)(4)	5,575		(4,794)	(2,360)	
Net income	$ 199,489	$ 73,847	$118,954	$132,349	$ 33,204
Earnings per share:					
Basic					
Income from continuing operations	$ 3.88	$ 1.52	$ 2.65	$ 2.81	$ 0.64
Income (loss) from discontinued operations	(0.31)	0.12	0.15	0.37	0.17
Cumulative effect of change in accounting principle, net of tax(2)(3)(4)	0.10		(0.11)	(0.05)	

Net income	$ 3.67	$ 1.64	$ 2.69	$ 3.13	$ 0.81

	Year Ended December 31,				
	2003	2002	2001	2000	1999
	(In thousands, except per share data)				
Diluted					
Income from continuing operations	$ 3.77	$ 1.51	$ 2.53	$ 2.65	$ 0.63
Income (loss) from discontinued operations	(0.30)	0.10	0.13	0.33	0.16
Cumulative effect of change in accounting principle, net of tax(2)(3)(4)	0.10		(0.10)	(0.05)	
Net income	$ 3.57	$ 1.61	$ 2.56	$ 2.93	$ 0.79
Weighted average number of shares outstanding for basic earnings per share	54,347	45,096	44,258	42,333	41,194
Weighted average number of shares outstanding for diluted earnings per share	56,744	49,589	48,894	47,228	42,294
Cash Flow Data:					
Net cash provided by continuing operating activities	$ 659,167	$ 383,257	$ 495,623	$ 289,384	$ 178,916
Net cash used in continuing investing activities	(614,708)	(501,816)	(754,540)	(339,303)	(205,971)
Net cash provided by (used in) continuing financing activities	(85,352)	137,030	273,127	15,933	67,758
Balance Sheet Data (at end of period):					
Working capital surplus (deficit)	$ (61,302)	$ (56,980)	$ 65,573	$ 38,497	$ 35,202
Oil and gas properties, net(4)	2,418,500	1,986,912	1,395,320	822,273	640,746
Total assets	2,733,089	2,315,753	1,663,371	1,023,250	781,561
Long-term debt	643,459	709,615	428,631	133,711	124,679
Convertible preferred securities		143,750	143,750	143,750	143,750
Stockholders equity	1,368,578	1,009,231	709,978	519,455	375,018
Reserve Data (at end of period):					
Proved reserves:					
Oil and condensate (MBbls)	37,774	34,037	30,959	22,551	19,637
Gas (MMcf)	1,090,140	977,115	718,312	519,723	440,173
Total proved reserves (MMcfe)	1,316,786	1,181,337	904,066	655,029	557,992
Present value of estimated future after-tax net cash flows	$2,935,439	$2,246,960	$ 958,863	$2,653,353	$ 713,065

(1) General and administrative expense includes stock compensation charges of $3,059, $2,801, $2,751, $3,047 and $1,999 for 2003, 2002, 2001, 2000 and 1999, respectively. See Note 13, Stock-Based Compensation *Restricted Shares*, to our consolidated financial statements.

(2) We adopted Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities, on January 1, 2001. SFAS No. 133 requires us to record all derivative instruments as either assets or liabilities on our balance sheet and measure those instruments at fair value. For all periods prior to January 1, 2001, we accounted for commodity price hedging instruments in accordance with SFAS No. 80. The cumulative effect of adoption of SFAS No. 133 is a reduction in net income of $4.8 million, or $0.10 per diluted share, and is shown as cumulative effect of change in accounting principle on our consolidated statement of income for the year ended December 31, 2001. On January 1, 2002, we began assessing hedge effectiveness based on the total changes in cash flows on our collar and floor contracts as described by Derivative Implementation Group (DIG) Issue G20, Cash Flow Hedges: Assessing and Measuring the Effectiveness of a Purchased Option Used in a Cash Flow Hedge. Accordingly, we have elected to prospectively record subsequent changes in the fair

value of our collar and floor contracts (other than contracts that are part of three-way collar contracts), including changes associated with time value, in accumulated other comprehensive income (loss). Gains or losses on these collar and floor contracts will be reclassified out of other comprehensive income (loss) and into earnings when the forecasted sale of production occurs. The expense recorded in 2002 is associated with the settlement of collar and floor contracts during the year ended December 31, 2002 and primarily reflects the reversal of time value gains of approximately $24.7 million recognized in earnings in 2001 prior to the adoption of DIG Issue G20. Had we applied DIG Issue G20 from the January 1, 2001 adoption date of SFAS No. 133, our income statement caption Commodity derivative income (expense) would have only reflected $0.5 million and $0.2 million of expense in 2002 and 2001, respectively, representing the ineffective portion of our hedges. As a result, net income would have increased by $18.6 million in 2002 and decreased by $16.3 million in 2001.

(3) We adopted SEC Staff Accounting Bulletin (SAB) No. 101, Revenue Recognition in Financial Statements, effective January 1, 2000. The adoption of SAB No. 101 requires us to report crude oil inventory associated with our Australian offshore operations at the lower of cost or market, which was a change from our historical policy of recording such inventory at market value on the balance sheet date, net of estimated costs to sell. The cumulative effect of the change from the acquisition date of our Australian operations in July 1999 through December 31, 1999 was a reduction in net income of $2.36 million, or $0.05 per diluted share, and is shown as the cumulative effect of change in accounting principle on our consolidated statement of income for the year ended December 31, 2000.

(4) We adopted SFAS No. 143, Accounting for Asset Retirement Obligations, on January 1, 2003. This statement changes the method of accounting for expected future costs associated with our obligation to perform site reclamation, dismantle facilities and plug and abandon wells. As a result of the adoption of SFAS No. 143, we recognized an after-tax gain of $5.6 million for the cumulative effect of change in accounting principle. See Note 1, Organization and Summary of Significant Accounting Policies *Accounting for Asset Retirement Obligations*, to our consolidated financial statements.

(5) On September 5, 2003, we sold our wholly owned subsidiary, Newfield Exploration Australia Ltd., which held all of our Australian assets. As a result of the sale, the historical results of operations of Newfield Exploration Australia Ltd. are reflected on our consolidated financial statements as discontinued operations. See Note 2, Discontinued Operations, to our consolidated financial statements.

Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

Overview

We are an independent oil and gas company engaged in the exploration, development and acquisition of crude oil and natural gas properties. Our areas of operation include the Gulf of Mexico, the U.S. onshore Gulf Coast, the Anadarko and Arkoma Basins, China s Bohai Bay and the North Sea.

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas and on our ability to find, develop and acquire oil and gas reserves that are economically recoverable. The preparation of our financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and gas reserves. We use the full cost method of accounting for our oil and gas activities.

Oil and Gas Prices. Prices for oil and gas fluctuate widely. Oil and gas prices affect:

- the amount of cash flow available for capital expenditures;
- our ability to borrow and raise additional capital;
- the amount of oil and gas that we can economically produce; and
- the accounting for our oil and gas activities.

We generally hedge a substantial, but varying, portion of our anticipated future oil and gas production to, among other things, reduce our exposure to commodity price fluctuations.

Reserve Replacement. Generally, our producing properties in the Gulf of Mexico and the onshore Gulf Coast often have high initial production rates, followed by steep declines. As a result, we must locate and develop or acquire new oil and gas reserves to replace those being depleted by production. Substantial capital expenditures are required to find, develop and acquire oil and gas reserves.

Significant Estimates. We believe the most difficult, subjective or complex judgments and estimates we must make in connection with the preparation of our financial statements are:

- remaining proved oil and gas reserves;
- timing of our future drilling, development and abandonment activities;
- future costs to develop and abandon our oil and gas properties;
- allocating the purchase price associated with business combinations; and
- the valuation of our derivative positions.

Please see Other Factors Affecting Our Business and Financial Results in this Item 7 for a more detailed discussion of a number of other factors that affect our business, financial condition and results of operations.

Results of Operations

On September 5, 2003, we sold our wholly owned subsidiary, Newfield Exploration Australia Ltd., which held all of our Australian assets. As a result of the sale, the historical results of operations of Newfield Exploration Australia Ltd. are reflected on our consolidated financial statements as discontinued operations. Please see Note 2, Discontinued Operations, to our consolidated financial statements appearing later in this report. Except where noted, discussions in this report relate to our continuing activities.

Revenues. All of our revenues are derived from the sale of our oil and gas production and the settlement of hedging contracts associated with our production. Our revenues may vary significantly from year to year as a result of changes in commodity prices and/or production volumes. Revenues for 2003 reached a record

$1.0 billion, and were 62% higher than 2002 revenues primarily because of higher natural gas and crude oil prices and a 25% increase in production.

	Year Ended December 31,		
	2003	2002	2001
Production:			
Natural gas (Bcf)	184.2	144.7	133.2
Oil and condensate (MBbls)	6,054	5,235	5,522
Total (Bcfe)	220.6	176.1	166.3
Average Realized Prices[(1)]:			
Natural gas (per Mcf)	$ 4.58	$ 3.42	$ 4.32
Oil and condensate (per Bbl)	27.65	24.21	24.01
Natural gas equivalent (per Mcfe)	4.58	3.53	4.26

(1) For purposes of this table, average realized prices for natural gas and oil and condensate are presented net of all applicable transportation expenses, which reduced the realized price of natural gas by $0.02, $0.03 and $0.03 for the years ended 2003, 2002 and 2001, respectively. The realized price of oil and condensate was reduced by $0.34, $0.35 and $0.31 for the years ended 2003, 2002 and 2001, respectively. Average realized prices include the effects of hedging.

Production. Our total oil and gas production in 2003 (stated on a natural gas equivalent basis) increased 25% over 2002 levels. Production increased primarily because of the acquisition of EEX in November 2002 and other small acquisitions and successful drilling efforts in 2003. In addition, 2002 production was reduced by our decision to voluntarily curtail approximately one Bcfe of production in the first quarter of that year in response to low commodity prices and by the shut-in of four Bcfe of production in the second half of that year in response to storms in the Gulf of Mexico. Our 2002 total oil and gas production increased 6% over 2001 primarily as a result of successful drilling in the Gulf of Mexico and the Mid-Continent and the acquisition of EEX. These increases were partially offset by our voluntary curtailment and the weather related shut-ins described above.

Natural Gas. Our 2003 natural gas production increased 27% when compared to 2002. The increase primarily was the result of the EEX acquisition in November 2002. Our development drilling programs in South Texas, the Mid-Continent and the Gulf of Mexico also were major contributors to our production growth. In addition, 2002 production was reduced by our decision to voluntarily curtail approximately one Bcfe of production in the first quarter of that year in response to low commodity prices and by the shut-in of four Bcfe of production in the second half of that year in response to storms in the Gulf of Mexico. Our 2002 natural gas production was nearly 9% higher than 2001 levels. The increase was the result of successful drilling in the Gulf of Mexico and the Mid-Continent and the acquisition of EEX in November 2002. Partially offsetting this increase was our voluntary curtailment and the weather related shut-ins described above.

Crude Oil and Condensate. Our 2003 oil and condensate production increased 16% when compared to 2002 levels. Development drilling programs in the U.S. and the acquisition of EEX in November 2002 were partially offset by natural field declines in all producing regions. Our 2002 oil production decreased about 6% when compared to 2001 primarily reflecting natural field declines in the U.S.

Effect of Hedging on Realized Prices. The following table presents information about the effect of our hedging program on realized prices.

	Average Realized Prices		Ratio of Hedged to Non-Hedged Price(1)
	With Hedge	Without Hedge	
Natural Gas:			
Year ended December 31, 2003	$ 4.58	$ 5.13	89%
Year ended December 31, 2002	3.42	3.17	108%
Year ended December 31, 2001	4.32	4.14	104%
Crude Oil and Condensate:			
Year ended December 31, 2003	$27.65	$29.77	93%
Year ended December 31, 2002	24.21	24.45	99%
Year ended December 31, 2001	24.01	24.23	99%

(1) The ratio is determined by dividing the realized price (which includes the effects of hedging) by the price that otherwise would have been realized without hedging activities.

Operating Expenses. We are a growth-oriented company. As such, our proved reserves and production have grown steadily since our founding. Naturally, our recurring operating expenses have increased with our growth. As a result, we believe the most informative way to analyze changes in our recurring operating expenses from one period to another is on a unit-of-production, or Mcfe, basis. The following table presents information about our operating expenses for each of the years in the two-year period ended December 31, 2003.

	Unit-of-Production (Per Mcfe)			Amount (In thousands)		
	Year Ended December 31,		Percentage Increase (Decrease)	Year Ended December 31,		Percentage Increase (Decrease)
	2003	2002		2003	2002	
Lease operating	$0.54	$0.52	4%	$119,290	$ 90,768	31%
Production and other taxes	0.14	0.08	75%	31,737	13,285	139%
Transportation	0.03	0.03		6,359	5,708	11%
Depreciation, depletion and amortization	1.79	1.68	7%	394,701	295,054	34%
General and administrative(1)	0.28	0.31	(10%)	61,636	54,363	13%
Gas sales obligation settlement and redemption of securities	0.09		100%	20,475		100%
Total operating expenses	2.87	2.62	10%	634,198	459,178	38%
Total operating expenses excluding non-recurring items(2)	2.78	2.62	6%	613,723	459,178	34%

(1) Includes stock compensation charges of $3,059, or $0.01 per Mcfe, for 2003 and $2,081, or $0.02 per Mcfe, for 2002.

(2) Excludes the expenses associated with the settlement of our gas sales obligation and the redemption of our trust preferred securities during 2003 of $20,475, or $0.09 per Mcfe. We believe the most informative way to analyze changes in total operating expenses is to compare recurring operating expenses only. We discuss settlement of our gas sales obligation and the redemption of our trust preferred securities separately below. See *Gas Sales Obligation Settlement* and *Redemption of Trust Preferred Securities.*

Our total operating expenses (excluding the gas sales obligation and redemption of securities) for 2003, stated on a unit-of-production basis, increased 6% over 2002. The increase was primarily related to the following items:

Lease operating expense (LOE) on a unit-of-production basis for 2003 increased 4% over the same period of last year in large part due to the addition of higher cost onshore properties through the EEX acquisition and a higher level of workover activity in 2003.

Production taxes on a unit-of-production basis increased 75% in 2003 due to higher commodity prices when compared to the prior year. Additionally, a greater percentage of our production is now onshore and subject to production taxes.

Depreciation, depletion and amortization (DD&A) (excluding furniture, fixtures and equipment) for 2003 was $1.76 per Mcfe versus $1.66 per Mcfe for 2002. Our adoption of SFAS No. 143 on January 1, 2003 (see *Cumulative Effect of Change in Accounting Principle Adoption of SFAS No. 143*) resulted in $0.03 per Mcfe of the increase. The remainder of the increase resulted from the increased cost of reserve additions during the year.

General and administrative expense (G&A) for 2003, before stock compensation expense and capitalized direct internal costs, on a unit-of-production basis, increased $0.05 per Mcfe or 16%, as compared to the same period of 2002. This increase is primarily due to increased salaries and benefits related to an increase in the number of employees due to growth of the company, a payment made to employees located in EEX s San Antonio, Texas office upon the closing of the office in June 2003, and an increase in incentive compensation expense due to the significant increase in 2003 earnings. This increase was offset by an increase in capitalized direct internal costs. During 2003, we capitalized $26.7 million of direct internal costs, compared to $7.0 million in 2002.

The following table presents information about our operating expenses for each of the years in the two-year period ended December 31, 2002.

	Unit-of-Production (Per Mcfe)			Amount (In thousands)		
	Year Ended December 31,		Percentage Increase (Decrease)	Year Ended December 31,		Percentage Increase (Decrease)
	2002	2001		2002	2001	
Lease operating	$0.52	$0.52		$ 90,768	$ 85,683	6%
Production and other taxes	0.08	0.09	(11%)	13,285	14,424	(8%)
Transportation	0.03	0.03		5,708	5,569	2%
Depreciation, depletion and amortization	1.68	1.65	2%	295,054	274,893	7%
General and administrative[(1)]	0.31	0.26	19%	54,363	42,621	28%
Ceiling test writedown		0.64	(100%)		106,011	(100%)
Total operating expenses	2.62	3.18	(18%)	459,178	529,201	(13%)

(1) Includes stock compensation charges of $2,801, or $0.02 per Mcfe, for 2002, and $2,751, or $0.02 per Mcfe, for 2001.

Our total operating expenses for 2002, stated on a unit-of-production basis, decreased 18% compared to the prior year. This decrease was primarily related to the ceiling test writedown recorded in 2001. Excluding the ceiling test writedown, our total operating expenses for 2002, stated on a unit-of-production basis, increased 3% over 2001. This increase was primarily related to the following items:

Lease operating expense on a unit-of-production basis for 2002 remained flat compared to the same period of 2001. The earlier period included a $5.5 million non-recurring expense associated with a workover of a well at South Marsh Island 160. Without the effect of the workover, lease operating expense for 2002 would have increased 13%, or $0.04 per unit, as a result of several non-routine repairs to gathering lines and other offshore facilities in the Gulf of Mexico and a slight increase in well service costs in the Mid-Continent.

Although our production subject to production taxes increased 14% in 2002, our production tax expense decreased because of a 21% drop in natural gas prices for the year.

The increase in our DD&A rate was primarily related to the increased cost of reserve additions. The cost of reserve additions was adversely affected by the quantity of proved reserves added and increases in the cost of drilling goods and services and platforms and facilities construction during the first half of 2001. The increase is partially offset by our fourth quarter 2001 ceiling test writedown of our oil and gas properties.

General and administrative expense increased primarily because of a growing domestic workforce and the opening of our office in London, England. During 2002, we capitalized $7.0 million of direct internal costs, compared to $5.3 million in 2001.

Writedown of Oil and Gas Properties. We did not writedown any of our oil and gas properties in 2003 or 2002. At December 31, 2001, the unamortized cost of our domestic oil and gas properties exceeded the cost center ceiling. In accordance with full cost accounting rules, we recorded a domestic ceiling test writedown at December 31, 2001 of $106 million ($68 million after-tax). The full cost ceiling test impairment calculations took into account the effects of hedging. The writedown would have been $184 million ($118 million after-tax) if we had not used hedge adjusted prices for the volumes that were subject to hedges.

Gas Sales Obligation Settlement. Pursuant to a gas forward sales contract entered into in 1999, EEX committed to deliver approximately 50 Bcf of production to Bob West Treasure L.L.C. (BWT) in exchange for proceeds of $105 million. As of the date of our acquisition of EEX, we recorded a liability of approximately $62 million, which represented the then current market value of approximately 16 Bcf of reserves remaining under the gas sales contact. We accounted for the obligation under the gas sales contract as debt on our consolidated balance sheet.

On March 31, 2003, pursuant to a settlement agreement with BWT and the other parties to related transactions, the gas sales contract, the swaps entered into by BWT in connection with the gas sales contract and all other agreements related to the gas sales contract, including the guarantee and all liens and other security interests on EEX s properties, were terminated in exchange for a payment by us of approximately $73 million. This payment represented:

the remaining unamortized obligation under the gas sales obligation;

the fair market value of swaps entered into by BWT in conjunction with the gas sales contract;

various transactions fees related to the termination; and

an agreed upon value for BWT s membership interest in an EEX subsidiary.

In connection with the settlement, we recognized a loss of $10 million under the caption Gas sales obligation settlement and redemption of securities on our consolidated statement of income.

Redemption of Trust Preferred Securities. We redeemed all of the outstanding 6 1/2% Cumulative Quarterly Income Convertible Preferred Securities of Newfield Financial Trust I on June 27, 2003 for an aggregate redemption price of approximately $148.4 million, or $38.31 on a per share of underlying common stock basis (excluding in each case accrued but unpaid distributions). The holders of only a small number of the securities elected to convert their securities into shares of our common stock prior to the redemption date (a total of 48,076 shares of common stock were issued). Included in the aggregate redemption price is $6.5 million of optional redemption premium. Upon redemption, this premium and $4.0 million of unamortized offering costs (which were being amortized over the 30-year life of the securities) were expensed under the caption Gas sales obligation settlement and redemption of securities on our consolidated statement of income.

We financed the redemption with the net proceeds from the issuance and sale of 3.5 million shares of our common stock on May 27, 2003 (approximately $131.2 million, or $37.49 per share) and borrowings under our revolving credit facility.

Interest Expense. The following table presents information about our interest expense for each of the years in the three-year period ended December 31, 2003.

	Year Ended December 31,		
	2003	2002	2001
	(In millions)		
Gross interest expense	$ 57.8	$ 34.5	$ 27.9
Capitalized interest	(15.9)	(8.8)	(8.9)
Net interest expense	41.9	25.7	19.0
Distributions on preferred securities	4.6	9.3	9.3
Total interest expense and distributions	$ 46.5	$ 35.0	$ 28.3

Our interest expense increased in both 2003 and 2002 as compared to the prior year because of higher debt levels outstanding under our credit arrangements and the issuance of our $250 million principal amount 8 3/8% Senior Subordinated Notes due 2011 in August 2002, the net proceeds of which were used to repay EEX debt that came due at the closing of the acquisition in November 2002 and transaction costs associated with the acquisition. Because the proceeds were held in escrow pending closing, interest that accrued prior to the closing (approximately $1.6 million) was capitalized as a cost of the transaction.

We also assumed $162.4 million of EEX obligations $100.8 million principal amount of secured notes and $61.6 million under a forward gas sales contract that remained outstanding following the closing. The secured notes accrued interest at a rate of 7.54% per year and the forward gas sales contract had an effective interest rate of 9.5% per year. In December 2002, we repurchased $23.6 million principal amount of the secured notes. During 2003, we repurchased or repaid $74.3 million principal amount of the secured notes. Premiums paid to the holders of the repurchased notes of $3.9 million were charged to interest expense in 2003. We also settled the forward gas sales contract in March 2003. The repurchase of secured notes and the settlement of the gas sales obligation were financed with borrowings under our credit arrangements. See Note 8, Debt *Secured Notes* and *Gas Sales Obligation Settlement*, to our consolidated financial statements.

Capitalized interest increased during 2003 because of our increased unproved property base resulting from the EEX acquisition. Distributions on preferred securities decreased in 2003 due to the redemption of our trust preferred securities in June 2003. See Note 10, Redemption of Trust Preferred Securities, to our consolidated financial statements.

Commodity Derivative Income (Expense). As a result of our adoption of SFAS No. 133 effective January 1, 2001, we are now required to record all derivative instruments on the balance sheet at fair value. The unrealized expense of $6.1 million for the year ended 2003 primarily represents the hedge ineffectiveness associated with our hedging program ($1.1 million) and the fair value adjustment for our three-way collar contracts that do not qualify for hedge accounting ($5.0 million). The unrealized expense of $29.1 million in 2002 primarily reflects the reversal of the time value gains that were previously recognized during 2001. The $24.8 million of unrealized income for the year ended 2001 primarily reflects the change in the time value of our open hedging contracts. For a further description of these items, please see Note 6, Commodity Derivative Instruments and Hedging Activities, to our consolidated financial statements appearing in this Form 10-K.

Taxes. The effective tax rate for the years ended December 31, 2003, 2002 and 2001 was 36%. The effective tax rate for all three years was more than the federal statutory tax rate primarily due to the state income taxes associated with applicable income from various states.

Cumulative Effect of Change in Accounting Principle Adoption of SFAS No. 143. We adopted SFAS No. 143, Accounting for Asset Retirement Obligations, as of January 1, 2003. This statement changes the method of accounting for expected future costs associated with our obligation to perform site reclamation, dismantle facilities and plug and abandon wells. Prior to January 1, 2003, we recognized the undiscounted estimated cost to abandon our oil and gas properties over their estimated productive lives on a unit-of-production basis as a component of DD&A expense and no liability or capitalized costs associated with such abandonment were recorded on our consolidated balance sheet. SFAS No. 143 requires that, if a reasonable estimate of the fair value of an abandonment obligation can be made, a liability (an asset retirement obligation or ARO) will be recorded on our consolidated balance sheet and the asset retirement cost will be capitalized in oil and gas properties in the period in which the retirement obligation is incurred.

In general, the amount of an ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor after discounting the future cost back to the date that the abandonment obligation was incurred using an assumed cost of funds for our company. After recording these amounts, the ARO will be accreted to its future estimated value using the same assumed cost of funds and the additional capitalized costs will be depreciated on a unit-of-production basis over the productive life of the related properties. Both the accretion and the depreciation are included in DD&A expense on our consolidated statement of income.

At adoption of SFAS No. 143, a cumulative effect of change in accounting principle was required in order to recognize:

- an initial ARO as a liability on our consolidated balance sheet;
- an increase in oil and gas properties for the cost to abandon our oil and gas properties;
- cumulative accretion of the ARO from the period incurred up to the January 1, 2003 adoption date; and
- cumulative depreciation on the additional capitalized costs included in oil and gas properties up to the January 1, 2003 adoption date.

As a result of our adoption of SFAS No. 143, we recorded a $134.8 million increase in the net capitalized costs of our oil and gas properties and an initial ARO of $128.5 million. Additionally, we recognized an after-tax gain of $5.6 million (the after-tax amount by which additional capitalized costs, net of accumulated depreciation, exceeded the initial ARO, including in each case discontinued operations) as the cumulative effect of change in accounting principle.

Results of Discontinued Operations

On September 5, 2003, we sold our wholly owned subsidiary, Newfield Exploration Australia Ltd., which held all of our Australian assets. As a result of the sale, the historical financial position, results of operations and cash flow of Newfield Exploration Australia Ltd. are reflected in our financial statements as discontinued operations. Please see Note 2, Discontinued Operations, to our consolidated financial statements.

The results of operations of Newfield Exploration Australia Ltd., which have been reclassified as discontinued operations for the twelve months ended December 31, 2003, 2002 and 2001 are summarized as follows:

	Twelve Months Ended December 31,		
	2003	**2002**	**2001**
		(In thousands)	
Revenues	$ 15,485	$ 34,915	$ 35,353
Operating expenses	(21,888)	(29,068)	(29,347)
Income (loss) from operations	(6,403)	5,847	6,006
Other income (expense)	(3,478)	(2,940)	3,273
Income (loss) before income taxes	(9,881)	2,907	9,279
Income tax (provision) benefit	2,784	2,194	(2,885)
Income (loss) from operations	(7,097)	5,101	6,394
Loss on sale	(9,895)		
Income (loss) from discontinued operations	$(16,992)	$ 5,101	$ 6,394

The decrease in earnings from discontinued operations for the year ended 2003 compared to the same period in 2002 was primarily due to the loss on sale of Newfield Exploration Australia Ltd. of $9.9 million, a ceiling test writedown of $7.3 million ($5.1 million after-tax) recorded in the second quarter of 2003 and the timing of oil liftings from our FPSOs in 2003 as compared to 2002.

The decrease in earnings from discontinued operations for the year ended 2002 compared to the same period in 2001 was due to the timing of oil liftings from our FPSOs in 2002 as compared to 2001 and foreign currency exchange gains and losses. This decrease was offset by a $3.1 million tax benefit resulting from revised tax legislation enacted in Australia in 2002.

Liquidity and Capital Resources

Substantial capital is required to replace and grow reserves. Without the addition of new reserves, our production and revenues will decline rapidly. We achieve reserve replacement and growth primarily through successful exploration and development drilling and the acquisition of properties. We replaced 161%, 257% and 250% of our production for the years ended December 31, 2003, 2002 and 2001, respectively. Reserve replacement includes revisions, extensions, discoveries and other additions and purchases of properties (net of sales of properties). Historically, a large percentage of our proved reserves have been proved developed (87%, 93% and 93% as of the years ended December 31, 2003, 2002 and 2001, respectively). Fluctuations in commodity prices have been the primary reason for short-term changes in our cash flow from operating activities. The net long-term growth in our cash flow from operating activities is the result of growth in production as affected by period to period fluctuations in commodity prices.

We establish a capital budget at the beginning of each calendar year based on expected cash flow from operations for that year. In the past, we often have revised our capital budget upward several times during the year as the result of acquisitions or successful drilling. Because of the nature of the properties we own, only a small portion of our capital budget is nondiscretionary. Based on current commodity prices and the high percentage of our anticipated 2004 production that has been hedged, we currently anticipate that our cash flow will exceed our capital budget (which excludes acquisitions) by more than $100 million in 2004. This excess should allow us to pay down debt and other obligations during the year, unless we increase our capital budget.

Our cash flow from operations during 2003 exceeded our capital expenditures (including the acquisition of Primary Natural Resources) during that period. We used the excess cash flow to pay down debt (see

24

Credit Arrangements and *Cash Flows from Continuing Operations* below and Note 8, Debt, to our consolidated financial statements).

Credit Arrangements. We maintain our reserve-based revolving credit facility with JPMorgan Chase Manhattan Bank, as agent. The banks participating in the facility have committed to lend us up to $425 million. The amount available under the facility is subject to a calculated borrowing base determined by banks holding 75% of the aggregate commitments. The borrowing base is reduced by the principal amount of outstanding senior notes ($300 million at March 10, 2004) and 30% of the principal amount of any outstanding senior subordinated notes (a reduction of $75 million at March 10, 2004). The borrowing base is redetermined at least semi-annually and, after reduction for the foregoing items, was $425 million at March 10, 2004. No assurances can be given that the banks will not elect to redetermine the borrowing base in the future. The facility contains restrictions on the payment of dividends and the incurrence of debt as well as other customary covenants and restrictions. The facility matures on January 23, 2005. We are in the process of replacing the facility with a new four year, $600 million, senior unsecured, reserve-based revolving credit facility. We expect that the borrowing base features of the new facility will be substantially identical to those in the current facility.

We also have money market lines of credit with various banks. Our credit facility limits our borrowings under these lines to $40 million. At March 10, 2004, we had outstanding borrowings under our credit facility of $50 million and no borrowings under our money market lines. Consequently, at March 10, 2004, we had approximately $415 million of available capacity under our credit arrangements.

At December 31, 2003, the interest rate for our outstanding LIBOR-based loans was 2.5% and for our outstanding money market lines of credit was 3.0%. At December 31, 2002, the interest rate was 2.737% for LIBOR-based loans under our credit facility and 2.615% for the loans outstanding under the money market lines of credit.

During the third quarter of 2003, we entered into interest rate swap agreements which provide for us to pay variable and receive fixed interest payments and are designated as fair value hedges of a portion of our senior notes (see Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* and Note 8, Debt *Interest Rate Swaps,* to our consolidated financial statements.

Working Capital. Our working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under our credit arrangements. Generally, we use excess cash to pay down borrowings under our credit arrangements. As a result, we often have a working capital deficit or a relatively small amount of positive working capital. We had a working capital deficit of $61.3 million as of December 31, 2003. This compares to a working capital deficit of $57.0 million at the end of 2002 and a surplus of $65.6 million at the end of 2001. Our 2003 working capital deficit included $12.1 million in asset retirement obligations (see Note 1, Organization and Summary of Significant Accounting Policies *Accounting for Asset Retirement Obligations*). Our 2002 working capital deficit included an $11.2 million secured note payment due January 2003 and accrued severance costs associated with the EEX acquisition.

Cash Flows from Continuing Operations. Cash flow from operations is dependent upon our ability to increase production through exploration, development and acquisition activities and the prices of natural gas and oil. Our cash flow from operations also is impacted by changes in working capital. We sell substantially all of our natural gas and oil production under floating market contracts. Additionally, we enter into hedging arrangements to reduce our exposure to fluctuations in natural gas and oil prices and to achieve more predictable cash flow. However, these contracts also limit the benefits we would realize if prices increase. See Item 7A. *Quantitative and Qualitative Disclosures About Market Risk.* We typically receive the cash associated with accrued oil and gas sales within 45-60 days of production. As a result, cash flow from operations and income from operations generally correlate, but cash flow from operations is impacted by changes in working capital and is not affected by DD&A and commodity derivative income (expense).

Our net cash flows from continuing operations were $659.2 million in 2003, a 72% increase over the prior year. The increase was primarily due to a 30% increase in oil and gas prices and a 25% increase in production volumes as a result of our acquisition of EEX. See Results of Operations above. A substantial portion of the net increase of $38.0 million in other current assets in 2003 is related to a receivable for overpaid federal income taxes for 2003. Accounts payable and accrued liabilities and other liabilities decreased $40.0 million. Accounts payable fluctuate from period to period depending on the level of development and exploration activities in progress and the timing of payments made by us to vendors and other operators. In 2003, other liabilities decreased as a result of payments made by us in satisfaction of liabilities assumed in connection with our acquisition of EEX.

Our net cash flows from continuing operations decreased by 23% in 2002 as compared to 2001. The decrease was primarily due to a 21% decrease in gas prices and a 28% increase in general and administrative expenses. See Results of Operations above. The net increase of $12.8 million in accounts receivable oil and gas was primarily related to increases in joint interest billings and oil and gas receivables. Joint interest billings fluctuate from period to period depending on the number of wells operated by us and the timing of billings to and collections from other working interest owners. Oil and gas receivables increased primarily because of higher production in December 2002 compared to December 2001 and higher commodity prices in December 2002. Accounts payable and accrued liabilities increased by $13.3 million during 2002 as a result of our acquisition of EEX in November 2002.

Capital Expenditures. Our 2003 capital spending was $647 million, a 27% decrease from 2002 capital spending of $888 million. Capital spending in 2003 included approximately $142 million in acquisitions. In 2003, we also invested $302 million in domestic development, $155 million in domestic exploration, $32 million in other domestic leasehold activity and $16 million internationally. The largest component of 2002 spending was the $571 million acquisition of EEX in late 2002. In 2002, we also invested $150 million in domestic development, $106 million in domestic exploration, $53 million in other domestic acquisitions and $8 million internationally. In 2001, our capital spending totaled $846 million, including $435 million in acquisitions. The largest component of acquisition spending was our first quarter acquisition in the Mid-Continent. In 2001, we invested $302 million in domestic development, $97 million in domestic exploration and $12 million internationally.

We budgeted $600 million for capital spending in 2004, excluding acquisitions. We expect that 50% of this budget will be invested in the Gulf of Mexico (including deepwater), 40% in the onshore U.S. and the remainder internationally. We anticipate that our current capital expenditure budget for 2004 will be fully funded from cash flow from operations. To the extent that cash receipts during the year are slower than capital needs, we will make up the shortfall with borrowings under our credit arrangements. Actual levels of capital expenditures may vary significantly due to many factors, including the extent to which proved properties are acquired, drilling results, oil and gas prices, industry conditions and the prices and availability of goods and services. We continue to pursue attractive acquisition opportunities; however, the timing, size and purchase price of acquisitions are unpredictable. Historically, we have completed several acquisitions of varying sizes each year. Depending on the timing of an acquisition, we may spend additional capital during the year of the acquisition for drilling and development activities on the acquired properties.

Cash Flows from Financing Activities. Net cash flows used in financing activities for the year ended December 31, 2003 were $85.4 million compared to $137.0 million of net cash flows provided by financing activities for the same period of 2002. During 2003, we:

- repaid or repurchased $74.3 million principal amount of secured notes;
- settled our obligation under a gas sales contract, $62.0 million of which was accounted for as debt, in exchange for a cash payment by us;
- sold 3.5 million shares of our common stock for net proceeds of approximately $131.2 million, or $37.49 per share; and
- redeemed all of our outstanding trust preferred securities for an aggregate redemption price of approximately $148.4 million.

Contractual Cash Obligations

The table below summarizes our significant contractual cash payment obligations and commitments by maturity as of December 31, 2003.

	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
			(In thousands)		
Debt:					
Bank revolving credit facility	$ 90,000	$	$ 90,000	$	$
Money market lines of credit (1)	5,000	5,000			
7.45% Senior Notes due 2007	125,000			125,000	
7 5/8% Senior Notes due 2011	175,000				175,000
8 3/8% Senior Subordinated Notes due 2012	250,000				250,000
Secured Notes due 2009(2)	2,895	2,895			
Total debt	647,895	7,895	90,000	125,000	425,000
Other commitments:					
Interest payments	328,329	46,012	130,926	68,563	82,828
Derivative liabilities, net	46,300	40,500	5,800		
Asset retirement obligations	163,643	12,095	46,923	29,474	75,151
Operating leases(3)	17,352	3,756	10,760	2,836	
Total other commitments	555,624	102,363	194,409	100,873	157,979
Total contractual cash obligations and other commitments	$ 1,203,519	$ 110,258	$ 284,409	$ 225,873	$ 582,979

(1) Our capacity under our credit facility is available to repay current amounts due on our money market lines of credit and, therefore, these obligations have been classified as long-term on our consolidated balance sheet.

(2) As of December 31, 2003, all of the outstanding principal is classified as current because the secured notes were repaid in full in January 2004.

(3) See Note 16, Commitments and Contingencies *Lease Commitments*, to our consolidated financial statements.

Credit Arrangements. Please see Liquidity and Capital Resources *Credit Arrangements* in this Item 7 for a description of our bank revolving credit facility and money market lines of credit.

Senior Notes. In February 2001, we issued $175 million aggregate principal amount of our 7 5/8% Senior Notes due 2011 priced (at 99.931% of par) with a yield to maturity of 7.635%. Net proceeds from the offering of $173.1 million were used to repay outstanding indebtedness under our revolving credit facility incurred in connection with our January 2001 Mid-Continent acquisition. In October 1997, we issued $125 million aggregate principal amount of our 7.45% Senior Notes due 2007. Interest on our senior notes is payable semi- annually.

Our senior notes are unsecured and unsubordinated obligations and rank equally with all of our other existing and future unsecured and unsubordinated obligations. We may redeem some or all of our senior notes at any time before their maturity at a redemption price based on a make-whole amount plus accrued and

unpaid interest to the date of redemption. The indentures governing our senior notes contain covenants that limit our ability to, among other things:

- incur debt secured by certain liens;
- enter into sale/leaseback transactions; and
- enter into merger or consolidation transactions.

The indentures also provide that if any of our subsidiaries guarantee any of our indebtedness at any time in the future, then we will cause our senior notes to be equally and ratably guaranteed by that subsidiary.

Senior Subordinated Notes. On August 13, 2002, we sold $250 million aggregate principal amount of our 8 3/8% Senior Subordinated Notes due 2012 priced with a yield to maturity of 8.50%. The net proceeds from the offering of approximately $241.8 million were used to repay EEX debt that became due at the closing of the acquisition and to pay transaction costs. Because the proceeds were held in escrow pending the closing of the EEX acquisition, interest accrued prior to closing of the EEX acquisition of approximately $1.6 million was capitalized as a cost of the transaction. Interest on the notes is payable semi-annually. The notes are unsecured senior subordinated obligations that rank junior in right of payment to all of our present and future senior indebtedness. We may redeem some or all of the notes at any time on or after August 15, 2007 at a redemption price stated in the indenture governing the notes. Prior to August 15, 2007, we may redeem all but not part of the notes at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. In addition, before August 15, 2005, we may redeem up to 35% of the original principal amount of the notes with the net cash proceeds of certain sales of our common stock at 108.375% of the principal amount plus accrued and unpaid interest to the date of redemption.

The indenture governing our senior subordinated notes limits our ability to, among other things:

- incur additional debt;
- make restricted payments;
- pay dividends on or redeem our capital stock;
- make certain investments;
- create liens;
- make certain dispositions of assets;
- engage in transactions with affiliates; and
- engage in mergers, consolidations and certain sales of assets.

Secured Notes. In the second quarter of 2001, EEX assumed the obligations under the secured notes in connection with the termination of two leveraged leasing arrangements. The notes accrued interest at a rate of 7.54% per year and were secured by the floating production system and pipelines described in Note 5, Oil and Gas Assets *Floating Production System and Pipelines,* to our consolidated financial statements. At the time we acquired EEX, $100.8 million principal amount of secured notes were outstanding. In December 2002, we repurchased $23.6 million principal amount of the secured notes. During 2003, we repaid or repurchased $74.3 million of the $77.2 million outstanding principal amount of secured notes at year-end 2002. The notes were repurchased with borrowings under our credit arrangements. The remaining secured notes were repaid in full in January 2004.

Commitments under Joint Operating Agreements. The oil and gas industry operates in many instances through joint ventures under joint operating agreements, and our operations are no exception. Typically, the operator under a joint operating agreement enters into contracts, such as drilling contracts, for the benefit of all joint venture partners. Through the joint operating agreement, the non-operators reimburse, and in some cases advance, the funds necessary to meet the contractual obligations entered into by the operator. These obligations are typically shared on a working interest basis. The joint operating agreement provides remedies to the operator in the event that the non-operator does not satisfy its share of the contractual obligations.

Occasionally, the operator is permitted by the joint operating agreement to enter into lease obligations and other contractual commitments that are then passed on to the non-operating joint interest owners as lease operating expenses, frequently without any identification as to the long-term nature of any commitments underlying such expenses.

Employee Benefit Plan Obligations. In 2003, we contributed $474,000 to our funded pension plan and $237,000 to our unfunded post-retirement medical plan. In 2004, we anticipate making a contribution of $140,000 to our funded pension plan and $197,000 to our unfunded post-retirement medical plan. Contributions to our funded plan increase the plan assets while contributions to our unfunded plan are made to fund current period benefit payments. Future contributions to our funded pension plan will be affected by actuarial assumptions, market performance and individual year funding decisions. We are unable to accurately predict what contribution levels will be required beyond 2004 for our funded pension plan and unfunded post-retirement medical plan.

Stock Repurchase Program

On May 4, 2001, we announced that our Board of Directors authorized the expenditure of up to $50 million to repurchase shares of our common stock. Through December 31, 2001, we had purchased 823,000 shares for total consideration of $24.7 million at an average of $29.97 per share. During 2002, no shares were purchased under this program. In February 2003, our Board of Directors authorized the expenditure of up to $50 million from that date forward to repurchase shares of our common stock. No shares were purchased under this program.

Oil and Gas Hedging

We generally hedge a substantial, but varying, portion of our anticipated oil and gas production for the next 18-24 months as part of our risk management program. We use hedging to reduce price volatility, help ensure that we have adequate cash flow to fund our capital programs and manage price risks and returns on some of our acquisitions and drilling programs, such as our gas mining initiative. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. Approximately 75% of our 2003 production was subject to hedge positions. In 2002, 84% of our production was subject to hedge positions, compared to 68% in 2001.

While the use of these hedging arrangements limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. In addition, the use of hedging transactions may involve basis risk. Substantially all of our hedging transactions are settled based upon reported settlement prices on the NYMEX. We believe there is no material basis risk with respect to our natural gas price hedging contracts because substantially all of our hedged natural gas production is sold at market prices that historically have highly correlated to the settlement price. Because substantially all of our U.S. Gulf Coast oil production is sold at current market prices that historically have highly correlated to the NYMEX West Texas Intermediate price, we believe that we have no material basis risk with respect to these transactions. The actual cash price we receive, however, generally is about $2.00 per barrel less than the NYMEX West Texas Intermediate price when adjusted for location and quality differences.

The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. At December 31, 2003, Bank of Montreal, Morgan Stanley Capital Group, Inc., Barclays Bank PLC and J Aron & Company were the counterparties with respect to 82% of our future hedged production. Such contracts are accounted for as derivatives in accordance with SFAS No. 133.

In 2003, we entered into three-way collar derivative contracts. Although our three-way collar contracts are effective as economic hedges of our commodity price exposure, they do not qualify for hedge accounting under SFAS No. 133.

Please see the discussion and tables in Note 6, Commodity Derivative Instruments and Hedging Activities, to our consolidated financial statements for a description of the accounting applicable to our hedging program and a listing of open hedging contracts as of December 31, 2003 and the fair value of those contracts as of that date.

Between December 31, 2003 and March 10, 2004, we entered into the additional natural gas price hedging contracts set forth in the table below.

		NYMEX Contract Price Per MMBtu			
		Collars			
		Floors		Ceilings	
Period and Type of Contract	Volume in MMMBtus	Range	Weighted Average	Range	Weighted Average
April 2004 June 2004					
Collar contracts	5,250	$5.25	$5.25	$6.47 - $6.67	$6.60
July 2004 September 2004					
Collar contracts	5,250	5.25	5.25	6.47 - 6.67	6.60
October 2004 December 2004					
Collar contracts	1,750	5.25	5.25	6.47 - 6.67	6.60

Between December 31, 2003 and March 10, 2004, we entered into the additional oil price hedging contracts with respect to our Gulf Coast oil production set forth in the table below.

		NYMEX Contract Price Per Bbl				
			Collars			
			Floors		Ceilings	
Period and Type of Contract	Volume in Bbls	Swaps (Weighted Average)	Range	Weighted Average	Range	Weighted Average
July 2004 September 2004						
Price swap contracts	180,000	$30.73				
Collar contracts	330,000		$27.00 - $27.50	$27.14	$30.65 - $34.50	$32.51
October 2004 December 2004						
Price swap contracts	180,000	30.73				
Collar contracts	330,000		27.00 - 27.50	27.14	30.65 - 34.50	32.51
January 2005 June 2005						
Price swap contracts	90,000	30.05				
Collar contracts	390,000		27.00	27.00	30.65 - 32.30	31.64

Floating Production System and Pipelines

As a result of our acquisition of EEX in November 2002, we own a 60% interest in a floating production system (FPS), some offshore pipelines and a processing facility located at the end of the pipelines in shallow water. The FPS is a combination deepwater drilling rig and processing facility capable of simultaneous drilling and production operations. These infrastructure assets are not currently in service and we do not have a specific use for them in our offshore operations. At the time of acquisition, we estimated their fair market value to be $35 million and classified them as assets held for sale under the provisions of SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. This statement provides that an asset can only be classified as held for sale for one year. Accordingly, we have now re-categorized them as held in use assets and they will be periodically evaluated for possible impairment.

We have engaged brokers who survey the world market for potential application of the assets "as is" or "to-be-modified" for a particular application. We also have direct discussions with other operators about the potential application of the assets to their developments around the world. Because there is no established market for these unique assets, it is difficult to accurately estimate their fair market value. An immediate sale or a sale under distressed circumstances might realize less than the current carrying value of the assets. No assurance can be given that we will be successful in selling this asset or that any sale will recover the carrying value of the asset.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resource positions, or for any other purpose.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and gas reserves. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. Described below are the most significant policies we apply in preparing our financial statements, some of which are subject to alternative treatments under generally accepted accounting principles. We also describe the most significant estimates and assumptions we make in applying these policies. We discussed the development, selection and disclosure of each of these with our audit committee. See Results of Operations in this Item 7, and Note 1, Organization and Summary of Significant Accounting Policies, to our consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

For discussion purposes, we have divided our significant policies into four categories. Set forth below is an overview of each of our significant accounting policies by category.

We account for our oil and gas activities under the full cost method. This method of accounting requires the following significant estimates:

- remaining proved oil and gas reserves;
- costs withheld from amortization; and
- future costs to develop and abandon our oil and gas properties.

Accounting for business combinations requires estimates and assumptions regarding the allocation of the purchase price.

Accounting for stock-based compensation may be accounted for under one of two available methods.

Accounting for commodity derivative activities requires estimates and assumptions regarding the valuation of derivative positions.

Oil and Gas Activities

Accounting for oil and gas activities is subject to special, unique rules. Two generally accepted methods for accounting for oil and gas activities are available successful efforts and full cost. The most significant differences between these two methods are the treatment of exploration costs and the manner in which the carrying value of oil and gas properties are amortized and evaluated for impairment. The successful efforts method requires exploration costs to be expensed as they are incurred while the full cost method provides for the capitalization of these costs. Both methods generally provide for the periodic amortization of capitalized costs based on proved reserve quantities. Impairment of oil and gas properties under the successful efforts method is based on an evaluation of the carrying value of individual oil and gas properties against their estimated fair value, while impairment under the full cost method requires an evaluation of the carrying value of oil and gas properties included in a cost center against the net present value of future cash flows from the related proved reserves, using period-end prices and costs and a 10% discount rate.

Full Cost Method. We use the full cost method of accounting for our oil and gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties are capitalized into cost centers (the amortization base) that are established on a country-by-country basis. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs and delay rentals. Capitalized costs also include salaries, employee benefits, costs of consulting services and other expenses that are estimated to directly relate to our oil and gas activities. Interest costs related to unproved properties and properties under development also are capitalized. Although some of these costs will ultimately result in no additional reserves, we expect the benefits of successful wells to more than offset the costs of any unsuccessful ones. Costs associated with production and general corporate activities are expensed in the period incurred. The capitalized costs of our oil and gas properties, plus an estimate of our future development and abandonment costs, are amortized on a unit-of-production method based on our estimate of total proved reserves. Amortization is calculated separately on a country-by-country basis. 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.

Proved Oil and Gas Reserves. Our engineering estimates of proved oil and gas reserves directly impact financial accounting estimates, including depreciation, depletion and amortization expense and the full cost ceiling limitation. Proved oil and gas reserves are the estimated quantities of natural gas and crude oil reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under period-end economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The data for a given reservoir may change substantially over time as a result of numerous factors including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in oil and gas prices, operating costs and expected performance from a given reservoir also will result in revisions to the amount of our estimated proved reserves.

All reserve information in this report is based on estimates prepared by our petroleum engineering staff. As a requirement of our revolving credit facility, independent reserve engineers prepare separate reserve reports with respect to properties holding at least 80% of our proved reserves. For December 31, 2003, the independent reserve engineers reports covered properties representing 83% of our proved reserves and for such properties, the reserves were within 3% of the reserves we reported for such properties.

Depreciation, Depletion and Amortization. The quantities of estimated proved oil and gas reserves are a significant component of our calculation of depletion expense and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves are revised upward, earnings would increase due to lower depletion expense. Likewise, if reserves are revised downward, earnings would decrease due to higher depletion expense or due to a ceiling test writedown. To increase our DD&A rate by $0.01 per Mcfe for the year ended December 31, 2003 would require a decrease in our estimated proved reserves at December 31, 2002 of approximately 6.6 Bcfe.

Full Cost Ceiling Limitation. Under the full cost method, we are subject to quarterly calculations of a ceiling or limitation on the amount of our oil and gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and gas properties exceed the cost center ceiling, we are subject to a ceiling test writedown to the extent of such excess. If required, it would reduce earnings and impact stockholders equity in the period of occurrence and result in lower amortization expense in future periods. The ceiling limitation is applied separately for each country in which we have oil and gas properties.

The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. However, the associated prices of oil and natural gas reserves that are included in the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that prices and costs in effect as of the last day of the quarter are held constant. However, we may not be subject to a writedown if prices increase subsequent to the end of a quarter in which a writedown might otherwise be required. The full cost ceiling test impairment calculations also take into consideration the effects of hedging.

Given the volatility of natural gas and oil prices, it is reasonably possible that our estimate of discounted future net cash flows from proved reserves will change in the near term. If natural gas and oil prices decline, even if for only a short period of time, or if we have downward revisions to our estimated proved reserves, it is possible that writedowns of our oil and gas properties could occur in the future. At December 31, 2003, the ceiling with respect to our domestic oil and gas properties exceeded the net capitalized costs of those properties by approximately $1.2 billion. The net capitalized costs at December 31, 2003 with respect to our U.K. oil and gas properties were not significant.

Costs Withheld From Amortization. Unevaluated costs are excluded from our amortization base until we have evaluated the properties associated with these costs. The costs associated with unevaluated leasehold acreage, unamortized seismic data, wells currently drilling and capitalized interest are initially excluded from our amortization base. Leasehold costs are either transferred to our amortization base with the costs of drilling a well on the lease or are assessed quarterly for possible impairment or reduction in value. Leasehold costs are transferred to our amortization base to the extent a reduction in value has occurred or a charge is made against earnings if the costs were incurred in a country for which a reserve base has not been established. If a reserve base for a country in which we are conducting operations has not yet been established, an impairment requiring a charge to earnings may be indicated through evaluation of drilling results, relinquishing drilling rights or other information.

In addition, a portion of incurred (if not previously included in the amortization base) and future development costs associated with qualifying major development projects may be temporarily excluded from amortization. To qualify, a project must require significant costs to ascertain the quantities of proved reserves attributable to the properties under development (e.g., the installation of an offshore production platform from which development wells are to be drilled). Incurred and future costs are allocated between completed and future work. Any temporarily excluded costs are included in the amortization base upon the earlier of when the associated reserves are determined to be proved or impairment is indicated.

Our decision to withhold costs from amortization and the timing of the transfer of those costs into the amortization base involves a significant amount of judgment and may be subject to changes over time based on several factors, including our drilling plans, availability of capital, project economics and results of drilling on adjacent acreage. At December 31, 2003, we had approximately $331 million of costs excluded from our amortization base, including $25.7 million associated with development costs for our deepwater Gulf of Mexico project known as Glider, located at Green Canyon 247/248. Because the application of the full cost ceiling test at December 31, 2003 resulted in a significant excess of the cost-center ceiling over the carrying value of our oil and gas properties, inclusion of some or all of our unevaluated property costs in our amortization base, without adding any associated reserves, would not have resulted in a ceiling test writedown. However, our future depletion rate will increase to the extent such costs are transferred without any associated reserves.

Future Development and Abandonment Costs. Future development costs include costs incurred to obtain access to proved reserves such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, gathering systems and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon the type of production structure, depth of water, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and future abandonment costs on an annual basis.

The accounting for future abandonment costs changed on January 1, 2003 with the adoption of SFAS No. 143. This new standard requires that a liability for the discounted fair value of an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. See Results of Operations *Cumulative Effect of Change in Accounting Principle Adoption of SFAS No. 143.*

Holding all other factors constant, if our estimate of future abandonment or future development costs is revised upward, earnings would decrease due to higher depletion expense. Likewise, if these estimates are revised downward, earnings would increase due to lower depletion expense. To increase our DD&A rate by $0.01 per Mcfe for the year ended December 31, 2003 would require an increase in the present value of our estimated future abandonment or future development costs at December 31, 2002 of approximately $10.0 million.

Allocation of Purchase Price in Business Combinations

As part of our growth strategy, we actively pursue the acquisition of oil and gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. Our most significant estimates in our allocation typically relate to the value assigned to future recoverable oil and gas reserves and unproved properties. To the extent the consideration paid exceeds the fair value of the net assets acquired, we would be required to record the excess as an asset called goodwill. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain. The value allocated to the recoverable oil and gas reserves and unproved properties is subject to the cost center ceiling as described under *Full Cost Ceiling Limitation* earlier in this section.

Effective January 1, 2002, we adopted SFAS No. 142, Goodwill and Other Intangible Assets, under which goodwill is no longer subject to amortization. Rather, goodwill of each reporting unit is tested for impairment on an annual basis, or more frequently if an event occurs or circumstances change that would reduce the fair value of the reporting unit below its carrying amount. In making this assessment, we rely on a number of factors including operating results, business plans, economic projections and anticipated cash flows. As there are inherent uncertainties related to these factors and our judgment in applying them to the analysis of goodwill impairment, there is risk that the carrying value of our goodwill may be overstated or understated. If it is overstated, such impairment would reduce earnings during the period in which the impairment occurs and would result in a corresponding reduction to goodwill. We elected to make December 31 our annual assessment date.

Stock-Based Compensation

In accordance with current accounting standards, there are two alternative methods that can be used to account for stock-based compensation. The first method the intrinsic value method recognizes compensation cost as the excess, if any, of the quoted market price of our stock at the grant date over the amount an employee must pay to acquire the stock. Under the second method the fair value method compensation cost is measured at the grant date based on the value of an award and is recognized over the service period, which is usually the vesting period. Currently, we account for our stock-based compensation in accordance with the intrinsic value method. However, in Note 1, Organization and Summary of Significant Accounting Policies *Stock-Based Compensation*, to our consolidated financial statements we have provided tabular information for each of the years in the three-year period ended December 31, 2003 that compares our net income and earnings per share as reported and on a pro forma basis as if we had used the fair value method of accounting for stock-based compensation.

Commodity Derivative Activities

We utilize derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our future natural gas and oil production. We generally hedge a substantial portion of our anticipated oil and natural gas production for the next 18-24 months. We do not use derivative instruments for trading purposes. Most of our derivatives qualify for hedge accounting. Under the accounting rules, we designate these derivatives as cash flow hedges against the price that we will receive for our future oil and natural gas production. To the extent that changes in the fair values of these derivatives offset changes in the expected cash flows from our forecasted production, such amounts are not included in our consolidated results of operations. Instead, they are recorded directly to stockholders equity until the hedged oil or natural gas quantities are produced and sold. To the extent the change in the fair value of the derivative exceeds the change in the expected cash flows from the forecasted production, the change is recorded in income in the period it occurs. Derivatives that do not qualify for hedge accounting (such as three-way collar contracts) are carried at their fair value on our consolidated balance sheet. We recognize all changes in the fair value of these contracts on our consolidated statement of income in the period in which the change occurs.

In determining the amounts to be recorded, we are required to estimate the fair values of both the derivative and the associated hedged production at its physical location. Where necessary, we adjust NYMEX prices to other regional delivery points using our own estimates of future regional prices. Our estimates are based upon various factors that include closing prices on the NYMEX, over-the-counter quotations, volatility and the time value of options. The calculation of the fair value of our option contracts requires the use of an option-pricing model. The estimated future prices are compared to the prices fixed by the hedge agreements and the resulting estimated future cash inflows or outflows over the lives of the hedges are discounted to calculate the fair value of the derivative contracts. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts, regional price differences and interest rates. We periodically validate our valuations using independent third-parties quotations.

New Accounting Standards

In 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. This statement changes the method of accounting for costs associated with the retirement of long-lived assets (e.g. oil and gas production facilities, etc.) that we are obligated to incur. The statement requires that the fair value of the obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the asset retirement obligation be capitalized as part of the carrying amount of the associated asset. Under our previous accounting method, we recognized the cost to abandon our oil and gas properties over their productive lives on a unit-of-production basis. See Results of Operations *Cumulative Effect of Change in Accounting Principle Adoption of SFAS No. 143.*

In December 2002, the FASB issued SFAS No. 148, Accounting for Stock-Based Compensation-Transition and Disclosure, an amendment of FASB Statement No. 123. SFAS No. 148 provides alternative methods of accounting for entities that elect to transition from the intrinsic value method of accounting for stock-based compensation to the fair value method. In addition, this statement amends the disclosure requirements of SFAS No. 123 to require disclosures in both annual and interim financial statements about the method of accounting for stock-based compensation and the effect of the method used on reported results. We adopted the disclosure provisions of this statement in our 2002 year-end financial statements. We continue to apply the intrinsic value method of accounting for our stock-based compensation plans. See Critical Accounting Policies and Estimates *Stock-Based Compensation* and Note 1, Organization and Summary of Significant Accounting Policies *Stock-Based Compensation*, to our consolidated financial statements.

We adopted in 2002 or 2003, or will be required to adopt in 2004, several other new accounting standards. Please see Note 1, Organization and Summary of Significant Accounting Policies *Accounting Changes*, to our consolidated financial statements for a discussion of these additional new accounting standards. Our adoption of these additional new standards has not had or is not expected to have a material impact on our consolidated financial statements.

Recent Accounting Developments

SFAS No. 141, Business Combinations, and SFAS No. 142, Goodwill and Other Intangible Assets, were issued by the FASB in June 2001 and became effective for us on July 1, 2001 and January 1, 2002, respectively. SFAS No. 141 requires that all business combinations initiated after June 30, 2001 be accounted for using the purchase method and that certain intangible assets be disaggregated and reported separately from goodwill. SFAS No. 142 established new guidelines for accounting for goodwill and other intangible assets. Under the statement, goodwill and certain other intangible assets are reviewed annually for impairment but are not amortized. To our knowledge, substantially all publicly traded oil and gas companies have continued to include oil and gas rights and interests held under leases, governmental licenses or other contractual arrangements (leasehold interests) as part of oil and gas properties after SFAS No. 141 and SFAS No. 142 became effective. The Emerging Issues Task Force (EITF) has added the oil and gas industry s application of SFAS Nos. 141 and 142 to leasehold interests to an upcoming agenda. We continue to classify our leasehold interests as tangible oil and gas properties until further guidance is provided. See Note 1, Organization and Summary of Significant Accounting Policies *Recent Accounting Developments* to our consolidated financial statements.

Regulation

We are subject to complex laws that can affect the cost, manner or feasibility of doing business. Exploration, development, production and sale of oil and gas are subject to extensive federal, state, local and international regulation. We may be required to make large expenditures to comply with environmental and other governmental regulations. Matters subject to regulation include:

- discharge permits for drilling operations;
- drilling bonds;
- reports concerning operations;
- the spacing of wells;
- unitization and pooling of properties; and
- taxation.

Under these laws, we could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws could change in ways that substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could have a material adverse effect on our financial condition and results of operations.

Federal Regulation of Sales and Transportation of Natural Gas. Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated pursuant to several laws enacted by Congress and the regulations promulgated under these laws by the FERC. In the past, the federal government has regulated the prices at which gas could be sold. Congress removed all price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993. Congress could, however, reenact price controls in the future.

Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive federal and state regulation. From 1985 to the present, several major regulatory changes have been implemented by Congress and the FERC that affect the economics of natural gas production, transportation and sales. In addition, the FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies, that remain subject to the FERC s jurisdiction. These initiatives may also affect the intrastate transportation of gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and these initiatives generally reflect more light-handed regulation.

The ultimate impact of the complex rules and regulations issued by the FERC since 1985 cannot be predicted. In addition, many aspects of these regulatory developments have not become final but are still pending judicial and FERC final decisions. We cannot predict what further action the FERC will take on these matters. Some of the FERC s more recent proposals may, however, adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any action taken materially differently than other natural gas producers, gatherers and marketers with which we compete.

The Outer Continental Shelf Lands Act, or OCSLA, requires that all pipelines operating on or across the Outer Continental Shelf, or the Shelf, provide open-access, non-discriminatory service. There are currently no regulations implemented by the FERC under its OCSLA authority on gatherers and other entities outside the reach of its Natural Gas Act jurisdiction. In addition, the FERC retains authority under OCSLA to exercise jurisdiction over entities outside the reach of its Natural Gas Act jurisdiction if necessary to ensure non-discriminatory access to service on the Shelf. We do not believe that any FERC action taken under OCSLA will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers with which we compete.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue.

Federal Regulation of Sales and Transportation of Crude Oil. Our sales of crude oil and condensate are currently not regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products are dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. Certain regulations implemented by the FERC in recent years could result in an increase in the cost of transportation service on certain petroleum products pipelines. However, we do not believe that these regulations affect us any differently than other natural gas producers.

Federal Leases. The majority of our U.S. operations are located on federal oil and gas leases, which are administered by the MMS. These leases are issued through competitive bidding, contain relatively standardized terms and require compliance with detailed MMS regulations and orders pursuant to OCSLA (which are subject to change by the MMS). For offshore operations, lessees must obtain MMS approval for exploration plans and development and production plans prior to the commencement of such operations. In addition to permits required from other agencies (such as the Coast Guard, the Army Corps of Engineers and the Environmental Protection Agency), lessees must obtain a permit from the MMS prior to the commencement of drilling. The MMS has promulgated regulations requiring offshore production facilities located on the Shelf to meet stringent engineering and construction specifications. The MMS also has regulations restricting the flaring or venting of natural gas, and has proposed to amend such regulations to prohibit the flaring of liquid hydrocarbons and oil without prior authorization. Similarly, the MMS has promulgated other regulations governing the plugging and abandonment of wells located offshore and the removal of all production facilities. To cover the various obligations of lessees on the Shelf, the MMS generally requires that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be met. The cost of such bonds or other surety can be substantial and there is no assurance that bonds or other surety can be obtained in all cases. We are currently exempt from the supplemental bonding requirements of the MMS. Under certain circumstances, the MMS may require that our operations on federal leases be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition, cash flows and results of operations. The MMS regulations governing the calculation of royalties and the valuation of crude oil produced from federal leases provide that the MMS will collect royalties based upon the market value of oil produced from federal leases. On August 20, 2003, the MMS issued a proposed rule that would change certain components of its valuation procedures for the calculation of royalties owed for crude oil sales. The proposed changes include changing the valuation basis for transactions not at arm s length from spot to NYMEX prices adjusted for locality and quality differentials, and clarifying the treatment of transactions under a joint operating agreement. Final comments on the proposed rule were due on November 10, 2003. We cannot predict what action the MMS will take on this matter. We believe that the proposed rule will not have a material effect on our financial position, cash flows or results of operations.

State and Local Regulation of Drilling and Production. We own interests in properties located onshore Louisiana, Texas, New Mexico and Oklahoma. We also own interests in properties in the state waters offshore Texas and Louisiana. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilling and the plugging and abandonment of wells. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing of waste materials, the size of drilling and spacing units or proration units and the density of wells which may be drilled, unitization and pooling of oil and gas properties and establishment of maximum rates of production from oil and gas wells. Some states prorate production to the market demand for oil and gas.

Environmental Regulations. Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the obligation to perform investigatory and remedial activities or the imposition of injunctive relief. Environmental laws and regulations are complex, change frequently and have tended to become more stringent over time. Both onshore and offshore drilling in certain areas has been opposed by environmental groups and, in certain areas, has been restricted. To the extent laws are enacted or other governmental action is taken that prohibits or restricts onshore or offshore drilling or imposes environmental protection requirements that result in increased costs to the oil and gas industry in general, our business and prospects could be adversely affected.

The Oil Pollution Act of 1990, or OPA, imposes regulations on responsible parties related to the prevention of oil spills and liability for damages resulting from spills in U.S. waters. A responsible party includes the owner or operator of an onshore facility, vessel or pipeline, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns strict, joint and several liability to each responsible party for oil removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation, or if the party fails to report a spill or to cooperate fully in the cleanup. Even if applicable, the liability limits for offshore facilities require the responsible party to pay all removal costs, plus up to $75 million in other damages for offshore facilities and up to $350 million for onshore facilities. Few defenses exist to the liability imposed by OPA. Failure to comply with ongoing requirements or inadequate cooperation during a spill event may subject a responsible party to administrative, civil or criminal enforcement actions.

OPA also requires operators in the Gulf of Mexico to demonstrate to the MMS that they possess available financial resources that are sufficient to pay for certain costs that may be incurred in responding to an oil spill. Under OPA and MMS regulations, responsible parties are required to demonstrate that they possess financial resources sufficient to pay for environmental cleanup and restoration costs of at least $10 million for an oil spill in state waters and at least $35 million for an oil spill in federal waters. Since we currently have extensive operations in federal waters, we currently provide a total of $150 million in financial assurance to MMS. This $150 million in financial assurance is provided through $35 million in guaranteed net worth and $115 million in insurance.

In addition to OPA, our discharges to waters of the U.S. are further limited by the federal Clean Water Act, or CWA, and analogous state laws. CWA prohibits any discharge into waters of the United States except in compliance with permits issued by federal and state governmental agencies. Failure to comply with CWA, including discharge limits on permits issued pursuant to CWA, may also result in administrative, civil or criminal enforcement actions. OPA and CWA also require the preparation of oil spill response plans and spill prevention, control and countermeasure or SPCC plans. We have such plans in existence and are currently upgrading or, as necessary, developing SPCC plans that will satisfy new SPCC plan certification and implementation requirements that become effective in August 2004 and February 2005, respectively.

OCSLA authorizes regulations relating to safety and environmental protection applicable to lessees and permittees operating on the Shelf. Specific design and operational standards may apply to vessels, rigs, platforms, vehicles and structures operating or located on the Shelf. Violations of lease conditions or regulations issued pursuant to OCSLA can result in substantial administrative, civil and criminal penalties, as well as potential court injunctions curtailing operations and the cancellation of leases.

The Resource Conservation and Recovery Act, or RCRA, generally regulates the disposal of solid and hazardous wastes. Although RCRA specifically excludes from the definition of hazardous waste drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy, legislation has been proposed in Congress from time to time that would reclassify certain oil and gas exploration and production wastes as hazardous wastes, which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such legislation were to be enacted, it could increase our operating costs, as well as those of the oil and gas industry in general. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

The Comprehensive Environmental Response, Compensation, and Liability Act, also known as the Superfund law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a hazardous substance into the environment. Persons who are or were responsible for releases of hazardous substances under the Superfund law may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We currently own or lease onshore properties that have been used for the exploration and production of oil and gas for a number of years. Many of these onshore properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and any wastes that may have been disposed or released on them may be subject to the Superfund law, RCRA and analogous state laws, and we potentially could be required to investigate and remediate such properties, including soil or groundwater contamination by prior owners or operators, or to perform remedial plugging or pit closure operations to prevent future contamination.

We believe that we are in substantial compliance with current applicable U.S. federal, state and local environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. Our foreign operations are potentially subject to similar governmental controls and restrictions relating to the environment. We believe that we are in substantial compliance with any such foreign requirements pertaining to the environment. There can be no assurance, however, that current regulatory requirements will not change, currently unforeseen environmental incidents will not occur or past non-compliance with environmental laws or regulations will not be discovered.

Other Factors Affecting Our Business and Financial Results

Oil and gas prices fluctuate widely, and low prices for an extended period of time are likely to have a material adverse impact on our business. Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas. These prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under our credit facility is subject to periodic redeterminations 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.

Among the factors that can cause fluctuations are:

- the domestic and foreign supply of oil and natural gas;
- the price and availability of alternative fuels;
- weather conditions;
- the level of consumer demand;
- the price of foreign imports;
- world-wide economic conditions;
- political conditions in oil and gas producing regions; and
- domestic and foreign governmental regulations.

Our use of oil and gas price hedging contracts involves credit risk and may limit future revenues from price increases and result in significant fluctuations in our net income. We use hedging transactions with respect to a portion of our oil and gas production to achieve more predictable cash flow and to reduce our exposure to price fluctuations. While the use of hedging transactions limits the downside risk of price declines, their use may also limit future revenues from price increases. Hedging transactions also involve the risk that the counterparty may be unable to satisfy its obligations.

Our future success depends on our ability to find, develop and acquire oil and gas reserves. As is generally the case, our producing properties in the Gulf of Mexico and the onshore Gulf Coast often have high initial production rates, followed by steep declines. To maintain production levels, we must locate and develop or acquire new oil and gas reserves to replace those depleted by production. Without successful exploration or acquisition activities, our reserves, production and revenues will decline rapidly. We may be able to find and develop or acquire additional reserves at an acceptable cost. In addition, substantial capital is required to replace and grow reserves. If lower oil and gas prices or operating difficulties result in our cash flow from operations being less than expected or limit our ability to borrow under our credit arrangements, we may be unable to expend the capital necessary to locate and develop or acquire new oil and gas reserves.

Actual quantities of recoverable oil and gas reserves and future cash flows from those reserves most likely will vary from our estimates. Estimating accumulations of oil and gas is complex. The process relies on interpretations of available geologic, geophysic, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and

the judgment of the persons preparing the estimate.

The proved reserve information set forth in this report is based on estimates we prepared. Estimates prepared by others might differ materially from our estimates.

Actual quantities of recoverable oil and gas reserves, future production, oil and gas prices, revenues, taxes, development expenditures and operating expenses most likely will vary from our estimates. Any significant variance could materially affect the quantities and present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development and prevailing oil and gas prices. Our reserves may also be susceptible to drainage by operators on adjacent properties.

You should not assume that the present value of future net cash flows is the current market value of our estimated proved oil and gas reserves. In accordance with SEC requirements, we generally 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 be materially higher or lower than the prices and costs as of the date of the estimate.

If oil and gas prices decrease, we may be required to take writedowns. We may be required to writedown the carrying value of our oil and gas properties when oil and gas prices are low or if we have substantial downward adjustments to our estimated proved reserves, increases in our estimates of development costs or deterioration in our exploration results.

We capitalize the costs to acquire, find and develop our oil and gas properties under the full cost accounting method. The net capitalized costs of our oil and gas properties may not exceed the present value of estimated future net cash flows from proved reserves, using period-end oil and gas prices and a 10% discount factor, plus the lower of cost or fair market value for unproved properties. If net capitalized costs of our oil and gas properties exceed this limit, we must charge the amount of the excess to earnings. We review the carrying value of our properties quarterly, based on prices in effect (including the effect of our hedge positions) as of the end of each quarter or as of the time of reporting our results. The carrying value of oil and gas properties is computed on a country-by-country basis. Therefore, while our properties in one country may be subject to a writedown, our properties in other countries could be unaffected. Once incurred, a writedown of oil and gas properties is not reversible at a later date even if oil or gas prices increase.

We may be subject to risks in connection with acquisitions. The successful acquisition of producing properties requires an assessment of several factors, including:

recoverable reserves;

future oil and gas prices;

operating costs; and

potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every platform or well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an as is basis.

Competitive industry conditions may negatively affect our ability to conduct operations. Competition in the oil and gas industry is intense, particularly with respect to the acquisition of producing properties and proved undeveloped acreage. Major and independent oil and gas companies actively bid for desirable oil and gas properties, as well as for the equipment and labor required to operate and develop their properties. Many of our competitors have financial resources that are substantially greater than ours, which may adversely affect our ability to compete with these companies.

Drilling is a high-risk activity. Our future success will depend on the success of our drilling program. In addition to the numerous operating risks described in more detail below, these activities involve the risk that no commercially productive oil or gas reservoirs will be discovered. In addition, we often are uncertain as to the future cost or timing of drilling, completing and producing wells. Furthermore, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment.

The oil and gas business involves many operating risks that can cause substantial losses; insurance may not protect us against all these risks. These risks include:

- fires;
- explosions;
- blow-outs;
- uncontrollable flows of oil, gas, formation water or drilling fluids;
- natural disasters;
- pipe or cement failures;
- casing collapses;
- embedded oilfield drilling and service tools;
- abnormally pressured formations; and
- environmental hazards such as oil spills, natural gas leaks, pipeline ruptures and discharges of toxic gases.

If any of these events occur, we could incur substantial losses as a result of:

- injury or loss of life;
- severe damage or destruction of property, natural resources and equipment;
- pollution and other environmental damage;

- investigatory and clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of our operations; and
- repairs to resume operations.

If we experience any of these problems, our ability to conduct operations could be adversely affected.

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

We maintain insurance against some, but not all, of these potential risks and losses. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect us.

We have risks associated with our foreign operations. We currently have international activities and we continue to evaluate and pursue new opportunities for international expansion in select areas. Ownership of property interests and production operations in areas outside the United States is subject to the various risks inherent in foreign operations. These risks may include:

- currency restrictions and exchange rate fluctuations;
- loss of revenue, property and equipment as a result of expropriation, nationalization, war or insurrection;
- increases in taxes and governmental royalties;
- renegotiation of contracts with governmental entities and quasi-governmental agencies;
- changes in laws and policies governing operations of foreign-based companies;
- labor problems; and
- other uncertainties arising out of foreign government sovereignty over our international operations.

Our international operations may also be adversely affected by laws and policies of the United States affecting foreign trade, taxation and investment. In addition, if a dispute arises with respect to our foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of the courts of the United States.

Exploration in deepwater involves greater operating and financial risks than exploration at shallower depths. These risks could result in substantial losses. Deepwater drilling and operations require the application of recently developed technologies and involve a higher risk of mechanical failure. We will likely experience significantly higher drilling costs for any deepwater wells that we drill. In addition, much of the deepwater play lacks the physical and oilfield service infrastructure present in shallower waters. As a result, development of a deepwater discovery may be a lengthy process and require substantial capital investment, resulting in significant financial and operating risks.

In addition, as we carry out our drilling program in deepwater, it is likely that we will not initially serve as operator of the wells. As a result, we may have limited ability to exercise influence over operations for these properties or their associated costs. Our dependence on the operator and other working interest owners for these deepwater projects and our limited ability to influence operations and associated costs could prevent the realization of our targeted returns on capital in drilling or acquisition activities in the deepwater of the Gulf of Mexico. The success and timing of drilling and exploitation activities on properties operated by others therefore depend upon a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the availability of suitable offshore drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel;

the operator s expertise and financial resources;

approval of other participants in drilling wells; and

selection of technology.

Other independent oil and gas companies limited access to capital may change our exploration and development plans. Many independent oil and gas companies have limited access to the capital necessary to finance their activities. As a result, some of the other working interest owners of our wells may be unwilling or unable to pay their share of the costs of projects as they become due. These problems could cause us to change, suspend or terminate our drilling and development plans with respect to the affected project.

Forward-Looking Information

This report contains information that is forward-looking or relates to anticipated future events or results such as planned capital expenditures, the availability of capital resources to fund capital expenditures, estimates of proved reserves and the estimated present value of such reserves, wells planned to be drilled in the future, our financial position, business strategy and other plans and objectives for future operations. Although we believe that the expectations reflected in this information are reasonable, this information is based upon assumptions and anticipated results that are subject to numerous uncertainties. Actual results may vary significantly from those anticipated due to many factors, including drilling results, oil and gas prices, industry conditions, the prices of goods and services, the availability of drilling rigs and other support services, the availability of capital resources and other factors affecting our business described above under the captions Regulation and Other Factors Affecting Our Business and Financial Results. All written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by such factors.

Commonly Used Oil and Gas Terms

Below are explanations of some commonly used terms in the oil and gas business.

Basis risk. The risk associated with the sales point price for oil or gas production varying from the reference (or settlement) price for a particular hedging transaction.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or condensate.

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf gas to one Bbl of crude oil or condensate.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Completion. The installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Deep shelf. We consider the deep shelf to be structures located on the shelf at depths generally greater than 15,000 feet in areas where there has been limited or no production from deeper stratigraphic zones.

Deepwater. Generally considered to be water depths in excess of 1,000 feet.

Developed acreage. The number of acres that are allocated or assignable to producing wells or wells capable of production.

Development well. A well drilled within the proved area of an oil or natural gas field to the depth of a stratigraphic horizon known to be productive, including a well drilled to find and produce probable reserves.

Dry hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Exploration or exploratory well. A well drilled to find and produce oil or natural gas reserves that is not a development well.

Farm-in or farm-out. An agreement whereunder the owner of a working interest in an oil and gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a farm-in, while the interest transferred by the assignor is a farm-out.

FERC. The Federal Energy Regulatory Commission.

FPSO. A floating production, storage and off-loading vessel, commonly used overseas to produce oil locations where pipeline infrastructure may not exist.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

Gas lift. The process of injecting natural gas into the wellbore to facilitate the flow of produced fluids from the reservoir to the production train.

Gross acres or gross wells. The total acres or wells in which we own a working interest.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil or condensate.

MMS. The Minerals Management Service of the United States Department of the Interior.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMcf. One million cubic feet.

MMcfe. One million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil or condensate.

Net acres or net wells. The sum of the fractional working interests we own in gross acres or gross wells, as the case may be.

NYMEX. The New York Mercantile Exchange.

Probable reserves. Reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Proved developed producing reserves. Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production to market.

Proved developed reserves. Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Proved developed nonproducing reserves. Proved developed reserves expected to be recovered from zones behind casing in existing wells.

Proved reserves. The estimated quantities of crude oil or natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Shelf. The U.S. Outer Continental Shelf of the Gulf of Mexico. Water depths generally range from 50 feet to 1,000 feet.

Tcfe. One trillion cubic feet equivalent, determined using the ratio of six Mcf gas to one Bbl of crude oil or condensate.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover. Operations on a producing well to restore or increase production.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

We are exposed to market risk from changes in oil and gas prices, interest rates and foreign currency exchange rates as discussed below.

Oil and Gas Prices

We generally hedge a substantial, but varying, portion of our anticipated oil and gas production for the next 18-24 months as part of our risk management program. We use hedging to reduce price volatility, help ensure that we have adequate cash flow to fund our capital programs and manage price risks and return on some of our acquisitions. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While hedging limits the downside risk of adverse price movements, it may also limit future revenues from favorable price movements. For a further discussion of our hedging activities, see the information under the caption Oil and Gas Hedging in Item 7 of this report.

Interest Rates

At December 31, 2003, we had $550 million in long-term fixed rate debt. This debt was comprised of:

$125 million of 7.45% Senior Notes due 2007;

$175 million of 7 5/8% Senior Notes due 2011; and

$250 million of 8 3/8% Senior Subordinated Notes due 2012.

Our year-end 2003 variable rate debt consisted of $90 million borrowed under our bank revolving credit facility and $5 million borrowed under our money market lines of credit. The interest rate at December 31, 2003 for our LIBOR based loans under our credit facility was 2.5% and the interest rate for the money market lines was 3.0%.

During 2003, we entered into interest rate swap agreements to take advantage of low interest rates and to obtain what we view as a more desirable proportion of variable and fixed rate debt. These swap agreements provide for us to pay variable and receive fixed interest payments, and are designated as fair value hedges of a portion of our outstanding senior notes. As of December 31, 2003, $50 million principal amount of our 7.45% Senior Notes due 2007 and $50 million principal amount of our 7 5/8% Senior Notes due 2011 were subject to interest rate swaps.

We considered our interest rate exposure at year-end 2003 to be minimal because about 70% of our long-term debt obligations, after taking into account our interest rate swap agreements, were at fixed rates. The impact on annual cash flow of a 10% change in the floating rate applicable to our variable rate debt would be $0.4 million.

Foreign Currency Exchange Rates

Our cash flow from certain international operations is based on the U.S. dollar equivalent of cash flows measured in foreign currencies. We consider our current risk exposure to exchange rate movements, based on net cash flows, to be immaterial. We did not have any open derivative contracts relating to foreign currencies at December 31, 2003.

Item 8. ***Financial Statements and Supplementary Data***

NEWFIELD EXPLORATION COMPANY
INDEX

CONSOLIDATED FINANCIAL STATEMENTS

AND SUPPLEMENTARY DATA

MANAGEMENT RESPONSIBILITY FOR FINANCIAL STATEMENTS

Our management is responsible for the preparation, integrity and objectivity of our consolidated financial statements and other financial information contained in this report. Our consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States and, accordingly, include certain informed judgments and estimates made by management. Our independent public accountants have audited the financial statements as described in their report that follows.

Management maintains a system of internal accounting and managerial controls that are designed to provide reasonable assurance that assets are safeguarded, transactions are properly recorded and executed in accordance with management s authorization and accounting records are reliable for financial statement preparation.

The Audit Committee of our Board of Directors, consisting solely of independent directors, meets regularly with management and our independent public accountants to monitor the integrity of our financial reporting process and system of internal controls. The independent accountants have full, free and separate access to the Audit Committee to discuss all appropriate matters.

We believe that our policies and system of accounting and managerial controls reasonably assure the integrity of our consolidated financial statements and the other information appearing in this report.

David A. Trice President and Chief Executive Officer	Terry W. Rathert Vice President and Chief Financial Officer

Houston, Texas
March 10, 2004

REPORT OF INDEPENDENT AUDITORS

To the Stockholders and Board of Directors of Newfield Exploration Company:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of income, of stockholders equity and of cash flows present fairly, in all material respects, the financial position of Newfield Exploration Company and its subsidiaries at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note 1 to the consolidated financial statements, the Company changed its method of accounting for asset retirement obligations effective January 1, 2003. Additionally, as described in Note 1 to the consolidated financial statements, the Company changed its method of assessing hedge effectiveness of its collar and floor contracts effective January 1, 2002 and its method of accounting for derivative instruments and hedging activities effective January 1, 2001.

Houston, Texas
March 10, 2004

NEWFIELD EXPLORATION COMPANY

CONSOLIDATED BALANCE SHEET

(In thousands, except share data)

	December 31, 2003	December 31, 2002
ASSETS		
Current assets:		
Cash and cash equivalents	$ 15,347	$ 48,898
Accounts receivable oil and gas	134,774	125,670
Inventories	553	1,260
Derivative assets	13,786	2,655
Deferred taxes	12,893	13,023
Other current assets	61,563	30,788
Assets of discontinued operations		16,533
Total current assets	238,916	238,827
Oil and gas properties (full cost method, of which $331,114 and $261,558 were excluded from amortization at December 31, 2003 and December 31, 2002, respectively)	4,078,115	3,299,022
Less accumulated depreciation, depletion and amortization	(1,659,615)	(1,312,110)
	2,418,500	1,986,912
Floating production system and pipelines	35,000	35,000
Furniture, fixtures and equipment, net	5,875	7,317
Derivative assets	2,223	4,439
Other assets	16,197	19,387
Goodwill	16,378	
Assets of discontinued operations		23,871
Total assets	$ 2,733,089	$ 2,315,753
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 30,556	$ 27,002
Accrued liabilities	204,054	198,084
Advances from joint owners	5,922	3,613
Secured notes payable	2,895	11,215
Asset retirement obligation	12,095	
Derivative liabilities	44,696	49,610
Liabilities of discontinued operations		6,283
Total current liabilities	300,218	295,807
Other liabilities	13,203	15,949
Derivative liabilities	13,244	10,610
Long-term debt	643,459	709,615
Asset retirement obligation	151,548	

Liabilities of discontinued operations		5,559
Deferred taxes	242,839	124,777
Total long-term liabilities	1,064,293	866,510
Company-obligated, mandatorily redeemable, convertible preferred securities of Newfield Financial Trust I		143,750
Minority interest		455
Commitments and contingencies		
Stockholders equity:		
Preferred stock ($0.01 par value, 5,000,000 shares authorized; no shares issued)		
Common stock ($0.01 par value, 100,000,000 shares authorized; 57,141,807 and 52,603,662 shares issued and outstanding at December 31, 2003 and December 31, 2002, respectively)	571	526
Additional paid-in capital	796,256	636,317
Treasury stock (at cost, 886,247 and 872,927 shares at December 31, 2003 and December 31, 2002, respectively)	(26,679)	(26,213)
Unearned compensation	(10,912)	(6,479)
Accumulated other comprehensive income (loss):		
Foreign currency translation adjustment	851	(3,888)
Commodity derivatives	(26,428)	(27,295)
Minimum pension liability	(833)	
Retained earnings	635,752	436,263
Total stockholders equity	1,368,578	1,009,231
Total liabilities and stockholders equity	$ 2,733,089	$ 2,315,753

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF INCOME

(In thousands, except share and per share data)

	Year Ended December 31,		
	2003	**2002**	**2001**
Oil and gas revenues	$ 1,016,986	$ 626,835	$ 714,052
Operating expenses:			
Lease operating	119,290	90,768	85,683
Production and other taxes	31,737	13,285	14,424
Transportation	6,359	5,708	5,569
Depreciation, depletion and amortization	394,701	295,054	274,893
Ceiling test writedown			106,011
General and administrative (includes non-cash stock compensation of $3,059, $2,801 and $2,751 for 2003, 2002 and 2001, respectively)	61,636	54,363	42,621
Gas sales obligation settlement and redemption of securities	20,475		
Total operating expenses	634,198	459,178	529,201
Income from operations	382,788	167,657	184,851
Other income (expenses):			
Interest expense	(57,803)	(34,515)	(27,859)
Capitalized interest	15,943	8,839	8,891
Dividends on convertible preferred securities of Newfield Financial Trust I	(4,581)	(9,344)	(9,344)
Commodity derivative income (expense)	(6,102)	(29,147)	24,821
Other	1,374	4,485	720
	(51,169)	(59,682)	(2,771)
Income from continuing operations before income taxes	331,619	107,975	182,080
Income tax provision:			
Current	21,647	37,502	29,975
Deferred	99,066	1,727	34,751
	120,713	39,229	64,726
Income from continuing operations	210,906	68,746	117,354
Income (loss) from discontinued operations, net of tax	(16,992)	5,101	6,394
Income before cumulative effect of change in accounting principle	193,914	73,847	123,748
Cumulative effect of change in accounting principle, net of tax:			
Adoption of SFAS No. 133			(4,794)
Adoption of SFAS No. 143	5,575		
Net income	$ 199,489	$ 73,847	$ 118,954

Earnings per share:			
Basic			
Income from continuing operations	$ 3.88	$ 1.52	$ 2.65
Income (loss) from discontinued operations	(0.31)	0.12	0.15
Cumulative effect of change in accounting principle, net of tax	0.10		(0.11)
Net income	$ 3.67	$ 1.64	$ 2.69
Diluted			
Income from continuing operations	$ 3.77	$ 1.51	$ 2.53
Income (loss) from discontinued operations	(0.30)	0.10	0.13
Cumulative effect of change in accounting principle, net of tax	0.10		(0.10)
Net income	$ 3.57	$ 1.61	$ 2.56
Weighted average number of shares outstanding for basic earnings per share	54,346,686	45,095,619	44,258,018
Weighted average number of shares outstanding for diluted earnings per share	56,744,287	49,589,260	48,893,627

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY

(In thousands, except share data)

	Common Stock		Treasury Stock		Additional Paid-In	Unearned	Retained	Accumulated Other Comprehensive Income	Total Stockholders
	Shares	Amount	Shares	Amount	Capital	Compensation	Earnings	(Loss)	Equity
Balance, December 31, 2000	42,625,764	$ 426	(18,463)	$ (399)	$ 286,811	$ (6,201)	$ 243,462	$ (4,644)	$ 519,455
Issuance of common stock	2,215,545	22			71,474				71,496
Issuance of restricted stock, less amortization of $852 and cancellations	120,968	1			4,395	(3,544)			852
Treasury stock, at cost			(842,292)	(25,395)					(25,395)
Amortization of stock compensation						1,900			1,900
Tax benefit from exercise of stock options					2,054				2,054
Comprehensive income:									
Net income							118,954		118,954
Foreign currency translation adjustment, net of tax of $2,301								(4,274)	(4,274)
Cumulative effect of accounting change, net of tax of $39,964								(74,218)	(74,218)
Reclassification adjustments for settled contracts, net of tax of ($4,464)								8,290	8,290
Changes in fair value of outstanding hedging positions, net of tax of ($48,927)								90,864	90,864
Total comprehensive income									139,616
Balance, December 31, 2001	44,962,277	449	(860,755)	(25,794)	364,734	(7,845)	362,416	16,018	709,978
Issuance of common stock	7,598,589	76			267,676				267,752
Issuance of restricted stock, less amortization of $306 and cancellations	42,796	1			1,434	(1,129)			306
Treasury stock, at cost			(12,172)	(419)					(419)
Amortization of stock compensation						2,495			2,495
Tax benefit from exercise of stock options					2,473				2,473

Comprehensive income:									
Net income							73,847		73,847
Foreign currency translation adjustment, net of tax of ($2,708)								5,030	5,030
Reclassification adjustments for settled contracts, net of tax of $8,394								(15,589)	(15,589)
Changes in fair value of outstanding hedging positions, net of tax of $19,748								(36,642)	(36,642)
Total comprehensive income									26,646
Balance, December 31, 2002	52,603,662	526	(872,927)	(26,213)	636,317	(6,479)	436,263	(31,183)	1,009,231
Issuance of common stock	4,315,081	43			147,515				147,558
Issuance of restricted stock, less amortization of $1,002 and cancellations	223,064	2			7,490	(6,490)			1,002
Treasury stock, at cost			(13,320)	(466)					(466)
Amortization of stock compensation						2,057			2,057
Tax benefit from exercise of stock options					4,934				4,934
Comprehensive income:									
Net income							199,489		199,489
Foreign currency translation adjustment, net of tax of ($2,551)								4,739	4,739
Reclassification adjustments for settled contracts, net of tax of $25,922								(48,143)	(48,143)
Changes in fair value of outstanding hedging positions, net of tax of ($26,390)								49,010	49,010
Minimum pension liability, net of tax of $448								(833)	(833)
Total comprehensive income									204,262
Balance, December 31, 2003	57,141,807	$ 571	(886,247)	$ (26,679)	$ 796,256	$ (10,912)	$ 635,752	$ (26,410)	$ 1,368,578

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY

CONSOLIDATED STATEMENT OF CASH FLOWS

(In thousands)

	Year Ended December 31,		
	2003	**2002**	**2001**
Cash flows from operating activities:			
Net income	$ 199,489	$ 73,847	$ 118,954
Adjustments to reconcile net income to net cash provided by continuing operating activities:			
(Income) loss from discontinued operations, net of tax	16,992	(5,101)	(6,394)
Depreciation, depletion and amortization	394,701	295,054	274,893
Gas sales obligation settlement and redemption of securities	20,475		
Stock compensation	3,059	2,801	2,751
Commodity derivative (income) expense	6,102	29,147	(24,821)
Deferred taxes	99,066	1,727	34,751
Cumulative effect of change in accounting principle	(5,575)		4,794
Ceiling test writedown			106,011
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable oil and gas	(4,376)	(12,820)	78,688
(Increase) decrease in inventories	706	177	(724)
Increase in other current assets	(38,024)	(8,508)	(12,469)
(Increase) decrease in other assets	4,233	(9,480)	(12,825)
Increase (decrease) in accounts payable and accrued liabilities	(22,820)	13,311	(66,673)
Increase (decrease) in advances from joint owners	2,310	3,603	(2,651)
Increase (decrease) in other liabilities	(17,171)	(501)	1,338
Net cash provided by continuing activities	659,167	383,257	495,623
Net cash provided by discontinued activities	10,339	20,202	6,749
Net cash provided by operating activities	669,506	403,459	502,372
Cash flows from investing activities:			
Purchase of business, net of cash acquired, of $801, $17,839 and $1,467 for 2003, 2002 and 2001, respectively	(90,157)	(204,411)	(264,089)
Proceeds from sale of business	9,678		
Additions to oil and gas properties	(530,898)	(295,004)	(486,843)
Additions to furniture, fixtures and equipment	(3,331)	(2,401)	(3,608)
Net cash used in continuing activities	(614,708)	(501,816)	(754,540)
Net cash used in discontinued activities	(3,085)	(16,297)	(11,282)
Net cash used in investing activities	(617,793)	(518,113)	(765,822)
Cash flows from financing activities:			
Proceeds from borrowings under credit arrangements	1,569,000	654,700	1,488,000
Repayments of borrowings under credit arrangements	(1,510,000)	(747,700)	(1,368,000)
Proceeds from issuance of common stock	149,305	7,787	3,643
Purchases of treasury stock	(466)	(419)	(25,395)
Proceeds from issuance of senior notes			174,879

Proceeds from issuance of senior subordinated notes		247,920	
Repurchases of secured notes	(63,068)	(23,586)	
Repayments of secured notes	(11,215)		
Deliveries under the gas sales obligation	(8,442)	(1,672)	
Gas sales obligation settlement	(62,017)		
Redemption of trust preferred securities	(148,449)		
Net cash provided by (used in) continuing activities	(85,352)	137,030	273,127
Net cash provided by (used in) discontinued activities			
Net cash provided by (used in) financing activities	(85,352)	137,030	273,127
Effect of exchange rate changes on cash and cash equivalents	88	(88)	(1,518)
Increase (decrease) in cash and cash equivalents	(33,551)	22,288	8,159
Cash and cash equivalents from continuing operations, beginning of period	33,798	8,668	(5,542)
Cash and cash equivalents from discontinued operations, beginning of period	15,100	17,942	23,993
Cash and cash equivalents, end of period	$ 15,347	$ 48,898	$ 26,610

The accompanying notes to consolidated financial statements are an integral part of this statement.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Summary of Significant Accounting Policies:

Organization and Principles of Consolidation

We are an independent oil and gas company engaged in the exploration, development and acquisition of crude oil and natural gas properties. Our company was founded in 1989. Our initial focus area was the Gulf of Mexico. In the mid-1990s, we began to expand our operations to other select areas. Our areas of operation now include the Gulf of Mexico, the onshore U.S. Gulf Coast, the Anadarko and Arkoma Basins, China s Bohai Bay and the North Sea.

Our financial statements include the accounts of Newfield Exploration Company, a Delaware corporation, and its subsidiaries. All significant intercompany balances and transactions have been eliminated. Unless otherwise specified or the context otherwise requires, all references in these notes to Newfield, we, us or our are to Newfield Exploration Company and its subsidiaries.

On November 26, 2002, we acquired EEX Corporation. The acquisition was accounted for using the purchase method of accounting. As a result, the assets and liabilities of EEX and its subsidiaries were included in our December 31, 2002 balance sheet and our results of operations and cash flows for 2002 included 35 days (November 27 to December 31, 2002) of activity for EEX and its subsidiaries. At the time of the acquisition, we changed EEX s name to Newfield Exploration Gulf Coast Inc. However, to assist readers understanding of these notes, we continue to refer to this entity as EEX.

On September 5, 2003, we sold Newfield Exploration Australia Ltd., the holding company for all of our Australian assets. As a result of the sale, the historical results of operations of our Australia operations are reflected in our financial statements as discontinued operations. See Note 2, Discontinued Operations. Except where noted and for pro forma earnings per share, discussions in these notes relate to our continuing activities only.

Dependence on Oil and Gas Prices

As an independent oil and gas producer, our revenue, profitability and future rate of growth are substantially dependent upon prevailing prices for natural gas and oil, which are dependent upon numerous factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. The energy markets have historically been very volatile, and there can be no assurance that oil and gas prices will not be subject to wide fluctuations in the future. 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 and our access to capital and on the quantities of oil and gas reserves that may be economically produced.

Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, the reported amounts of revenues and expenses during the reporting period and the reported amounts of proved oil and gas reserves. Actual results could differ from these estimates. Our most significant financial estimates are based on remaining proved oil and gas reserves.

Reclassifications

Certain reclassifications have been made to prior year s reported amounts in order to conform with the current year presentation. These reclassifications, including those related to our discontinued operations (see Note 2, Discontinued Operations), did not impact our net income or stockholders equity.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Revenue Recognition

We record revenue when title passes to the customer. Revenues from the production of oil and gas from properties in which we have an interest with other companies are recorded on the basis of sales to customers. Differences between these sales and our share of production are not significant.

Inventories

Inventories consist of materials and supplies valued at the lower of average cost or market.

Foreign Currency

The functional currency for our operations in the United Kingdom is the British pound. The functional currency for all of our other foreign operations is the U.S. dollar. Translation adjustments resulting from translating our United Kingdom subsidiary s British pound financial statements into U.S. dollars are included as other comprehensive income on our consolidated statement of stockholders equity. Gains and losses incurred on currency transactions in other than a country s functional currency are included on our consolidated statement of income.

Financial Instruments

We have included fair value information in these notes when the fair value of our financial instruments is different from the book value. Cash equivalents include highly liquid investments with a maturity of three months or less when acquired. We invest cash in excess of operating requirements in U.S. Treasury Notes, Eurodollar bonds and investment grade commercial paper. Cash equivalents are stated at cost, which approximates fair value.

Oil and Gas Properties

We use the full cost method of accounting. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties, including salaries, benefits and other internal costs directly attributable to these activities, are capitalized into cost centers that are established on a country-by-country basis. We capitalized $26.7 million, $7.0 million and $5.3 million of internal costs in 2003, 2002 and 2001, respectively. Interest expense related to unproved properties and properties under development are also capitalized to oil and gas properties. Such capitalized costs and estimated future development and dismantlement costs are amortized on a unit-of-production method based on proved reserves. For each cost center, the net capitalized costs of oil and gas properties are limited to the lower of the unamortized cost or the cost center ceiling, defined as the sum of the present value (10% per annum discount rate) of estimated future net revenues from proved reserves, based on end of period oil and gas prices as adjusted for location and quality differences and the effects of hedging; plus the cost of properties not being amortized, if any; plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less related income tax effects.

Application of full cost accounting rules did not result in a ceiling test writedown in 2003 or 2002. However, we did record a domestic ceiling test writedown of $106 million ($68 million after-tax) at December 31, 2001. This impairment was primarily the result of lower commodity prices at year-end 2001. The full cost ceiling test impairment calculation took into account the effects of hedging. The writedown would have been $184 million ($118 million after-tax) if we had not used hedge adjusted prices for the volumes that were subject to hedges.

Proceeds from the sale of oil and gas properties are applied to reduce the costs in the cost center unless the sale involves a significant quantity of reserves in relation to the cost center, in which case a gain or loss is recognized.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Furniture, Fixtures and Equipment

Furniture, fixtures and equipment are recorded at cost and are depreciated over their estimated useful lives, which range between three and seven years, using the straight-line method. At December 31, 2003 and 2002, furniture, fixtures and equipment of $16.1 million and $22.8 million, respectively, is net of accumulated depreciation of $10.2 million and $15.5 million, respectively.

Accounting for Asset Retirement Obligations

We adopted SFAS No. 143, Accounting for Asset Retirement Obligations, as of January 1, 2003. This statement changes the method of accounting for expected future costs associated with our obligation to perform site reclamation, dismantle facilities and plug and abandon wells. Prior to January 1, 2003, we recognized the undiscounted estimated cost to abandon our oil and gas properties over their estimated productive lives on a unit-of-production basis as a component of depreciation, depletion and amortization expense and no liability or capitalized costs associated with such abandonment were recorded on our consolidated balance sheet. If a reasonable estimate of the fair value of an abandonment obligation can be made, SFAS No. 143 requires us to record a liability (an asset retirement obligation or ARO) on our consolidated balance sheet and to capitalize the asset retirement cost in oil and gas properties in the period in which the retirement obligation is incurred.

In general, the amount of an ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor after discounting the future cost back to the date that the abandonment obligation was incurred using an assumed cost of funds for our company. After recording these amounts, the ARO will be accreted to its future estimated value using the same assumed cost of funds and the additional capitalized costs will be depreciated on a unit-of-production basis over the productive life of the related properties. Both the accretion and the depreciation are included in depreciation, depletion and amortization on our consolidated statement of income.

At adoption of SFAS No. 143, a cumulative effect of change in accounting principle was required in order to recognize:

an initial ARO as a liability on our consolidated balance sheet;

an increase in oil and gas properties for the cost to abandon our oil and gas properties;

cumulative accretion of the ARO from the period incurred up to the January 1, 2003 adoption date; and

cumulative depreciation on the additional capitalized costs included in oil and gas properties up to the January 1, 2003 adoption date.

The change in our ARO since adoption of SFAS No. 143 is set forth below (in thousands):

Balance as of January 1, 2003	$128,471
Accretion expense	7,539
Additions	31,768
Settlements	(4,135)
Balance as of December 31, 2003	$163,643

As a result of our adoption of SFAS No. 143, we recorded a $134.8 million increase in the net capitalized costs of our oil and gas properties. Additionally, we recognized an after-tax gain of $5.6 million (the after-tax amount by which additional capitalized costs, net of accumulated depreciation, exceeded the initial ARO,

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

including in each case discontinued operations) for the cumulative effect of change in accounting principle. Had we adopted SFAS No. 143 on January 1, 2002, the pro forma ARO would have been $115.7 million.

Had SFAS No. 143 been applied retroactively to the years ended December 31, 2002 and 2001, our net income and earnings per share (without any cumulative effect of change in accounting principle) would have approximated the pro forma amounts below:

	Year Ended December 31,	
	2002	**2001**
	(In thousands, except per share data)	
Net income:		
As reported	$73,847	$118,954
Pro forma	72,792	116,182
Earnings per share:		
Basic		
As reported	$ 1.64	$ 2.69
Pro forma	1.61	2.63
Diluted		
As reported	$ 1.61	$ 2.56
Pro forma	1.59	2.50

Goodwill

We adopted SFAS No. 142, Goodwill and Other Intangible Assets, effective January 1, 2002. Under SFAS No. 142, which superseded Accounting Principles Board (APB) Opinion No. 17, Intangible Assets, goodwill is no longer subject to amortization but it is tested for impairment. The impairment test requires the allocation of goodwill and all other assets and liabilities to reporting units. The fair value of each reporting unit is determined and compared to the book value of that reporting unit. If the fair value of the reporting unit is less than the book value (including goodwill) then goodwill is reduced to its implied fair value and the amount of the write-down is charged to earnings. Goodwill is tested for impairment on an annual basis, or more frequently if an event occurs or circumstances change that have an adverse effect on the fair value of the reporting unit such that the fair value could be less than the book value of such unit.

As of December 31, 2003, we had recorded goodwill of $16.4 million, representing the excess of the purchase price over the estimated fair value of the assets acquired less the liabilities assumed in our Primary Natural Resources acquisition (see Note 4, Acquisitions *Primary Natural Resources*). We allocated all of the goodwill to our Mid-Continent reporting unit. This is the first time we have recorded goodwill in connection with an acquisition.

We perform our goodwill impairment test annually on December 31, or more frequently if indications of potential impairment appear. The fair value of the Mid-Continent reporting unit is based on our estimates of future net cash flows from proved reserves and from future exploration for and development of unproved reserves. Downward revisions of estimated reserves or production, increases in estimated future costs or decreases in oil and gas prices could lead to an impairment of all or a portion of this goodwill in future periods.

We determined that no goodwill impairment existed as of December 31, 2003.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Income Taxes

We use the liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are determined by applying tax regulations existing at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in the financial statements.

A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

Stock-Based Compensation

We account for our employee stock options using the intrinsic value method prescribed by APB Opinion No. 25.

If the fair value based method of accounting under SFAS No. 123, Accounting for Stock-Based Compensation, had been applied, our net income and earnings per common share for 2003, 2002 and 2001 would have approximated the pro forma amounts below:

	Year Ended December 31,		
	2003	2002	2001
	(In thousands, except per share data)		
Net income:			
As reported	$199,489	$73,847	$118,954
Pro forma	193,235	68,620	114,073
Basic earnings per common share			
As reported	$ 3.67	$ 1.64	$ 2.69
Pro forma	3.56	1.52	2.58
Diluted earnings per common share			
As reported	$ 3.57	$ 1.61	$ 2.56
Pro forma	3.46	1.51	2.46

Concentration of Credit Risk

We operate a substantial portion of our oil and gas properties. As the operator of a property, we make full payment for costs associated with the property and seek reimbursement from the other working interest owners in the property for their share of those costs. Our joint interest partners consist primarily of independent oil and gas producers. If the oil and gas exploration and production industry in general was adversely affected, the ability of our joint interest partners to reimburse us could be adversely affected.

Our oil and gas production purchasers consist primarily of independent marketers, major oil and gas companies and gas pipeline companies. We perform credit evaluations of, and monitor on an ongoing basis the financial condition of, the purchasers of our production. Based on our evaluation, we obtain cash escrows, letters of credit and parental guarantees from selected purchasers. Over the past several years, we have sold a substantial portion of our oil and gas production to two purchasers (see *Major Customers* below). The remaining portion of our production is sold to a number of major oil and gas companies and smaller marketing companies. We have not experienced any significant losses from uncollectible accounts.

All of our hedging transactions have been carried out in the over-the-counter market. The use of hedging transactions involves the risk that the counterparties may be unable to meet the financial terms of these transactions. The counterparties for all of our hedging transactions have an investment grade credit rating. We monitor on an ongoing basis the credit ratings of our hedging counterparties. At December 31, 2003, Bank

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of Montreal, Morgan Stanley Capital Group, Inc., Barclays Bank PLC and J Aron & Company were the counterparties with respect to 82% of our future hedged production.

Major Customers

We sold oil and gas production representing more than 10% of our revenues before the effects of hedging for the year ended December 31, 2003 to Superior Natural Gas Corporation (29%) and ConocoPhillips Inc. (25%); for the year ended December 31, 2002 to Superior Natural Gas Corporation (25%) and ConocoPhillips Inc. (23%); and for the year ended December 31, 2001 to Conoco Inc. (28%) and Superior Natural Gas Corporation (25%). Because alternative purchasers of oil and gas are readily available, we believe that the loss of either or both of these purchasers would not have a material adverse effect on us.

Derivative Financial Instruments

On January 1, 2001, we adopted SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended by SFAS No. 137, Accounting for Derivative Instruments and Hedging Activities Deferral of the Effective Date of FASB Statement No. 133, an amendment of FASB Statement No. 133, and SFAS No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activities, an amendment of FASB Statement No. 133. In accordance with the transition provisions of SFAS No. 133, on January 1, 2001, we recorded a cumulative effect adjustment loss of $114.2 million ($74.2 million net of tax) in accumulated other comprehensive loss and a loss of $7.4 million ($4.8 million net of tax) in 2001 earnings. In addition, the adoption resulted in the recognition of $17.7 million of derivative assets and $139.3 million of derivative liabilities on our consolidated balance sheet on January 1, 2001.

On January 1, 2002, we began assessing hedge effectiveness based on the total changes in cash flows on our collar and floor contracts as described by the Derivative Implementation Group (DIG) Issue G20, Cash Flow Hedges: Assessing and Measuring the Effectiveness of a Purchased Option Used in a Cash Flow Hedge. Accordingly, we elected to prospectively record subsequent changes in the fair value of our collar and floor contracts (other than contracts that are part of three-way collar contracts), including changes associated with time value, in accumulated other comprehensive income (loss). Gains or losses on these collar and floor contracts will be reclassified out of other comprehensive income (loss) and into earnings when the forecasted sale of production occurs. For the year ended December 31, 2002, we recorded $29.1 million of expense under the income statement caption Commodity derivative income (expense). This expense is associated with the settlement of collar and floor contracts during the twelve-month period ended December 31, 2002 and primarily reflects the reversal of time value gains of approximately $24.7 million recognized in earnings in 2001, prior to the adoption of DIG Issue G20. Had we applied DIG Issue G20 from the January 1, 2001 adoption date of SFAS 133, our income statement caption Commodity derivative income (expense) would have only reflected $0.5 million and $0.2 million of expense in 2002 and 2001, respectively, representing the ineffective portion of our hedges. As a result, net income would have increased by $18.6 million in 2002 and decreased by $16.3 million in 2001.

Although three-way collar contracts are effective as economic hedges of our commodity price exposure, they do not qualify for hedge accounting under SFAS No. 133. These contracts are carried at their fair value on our consolidated balance sheet under the captions Derivative assets and Derivative liabilities. We recognize all changes in the fair value of our three-way collar contracts on our consolidated statement of income for the period in which the change occurs under the caption Commodity derivative income (expense). Realized gains and losses on our three-way collar contracts are also recognized under the caption Commodity derivative income (expense).

See Note 6, Commodity Derivative Instruments and Hedging Activities, for a full discussion of our hedging activities.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Comprehensive Income (Loss)

Comprehensive income (loss) includes net earnings (loss) as well as unrealized gains and losses on derivative instruments, cumulative foreign currency translation adjustments and minimum pension liability, all recorded net of tax.

Accounting Changes

In the second quarter of 2002, the FASB issued SFAS No. 145, Recision of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections as of April 2002. This statement provides guidance on income statement classification of gains and losses on extinguishment of debt and accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. Our adoption of SFAS No. 145 on January 1, 2003 has had no effect on our financial statements.

In June 2002, the FASB issued SFAS No. 146, Accounting for Costs Associated with Exit or Disposal Activities. SFAS No. 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force (EITF) Issue No. 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring). SFAS No. 146 requires that a liability for costs associated with an exit or disposal activity be recognized when the liability is incurred and establishes that fair value is the objective for initial measurement of the liability. The provisions of SFAS No. 146 are effective for exit or disposal activities that are initiated after December 31, 2002. Our adoption of SFAS No. 146 on January 1, 2003 has had no effect on our financial statements.

In December 2002, the FASB issued SFAS No. 148, Accounting for Stock-Based Compensation-Transition and Disclosure, an amendment of FASB Statement No. 123. SFAS No. 148 provides alternative methods of accounting for entities that elect to transition from the intrinsic value method of accounting for stock-based compensation to the fair value method. In addition, this statement amends the disclosure requirements of SFAS No. 123 to require disclosures in both annual and interim financial statements about the method of accounting for stock-based compensation and the effect of the method used on reported results. We adopted the disclosure provisions of this statement beginning with our year-end 2002 consolidated financial statements. We continue to apply the intrinsic value method of accounting for our stock-based compensation plans.

In November 2002, the FASB issued Interpretation No. (FIN) 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others. FIN 45 requires certain guarantees to be recorded at fair value, which is different from the prior practice of recording a liability only when a loss was probable and reasonably estimable, as those terms are defined in SFAS No. 5, Accounting for Contingencies. FIN 45 had a dual effective date. The initial recognition and measurement provisions are applicable on a prospective basis only to guarantees issued or modified after December 31, 2002. The disclosure requirements in the interpretation were effective for us as of October 1, 2002. The adoption of the applicable provisions of FIN 45 at the indicated dates has not had a material effect on our financial statements.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In January 2003, the FASB issued FIN 46, Consolidation of Variable Interest Entities, an Interpretation of ARB 51. In December 2003, the FASB issued FIN 46R. The primary objectives of FIN 46R are to provide guidance on the identification of entities for which control is achieved through means other than through voting rights (these entities are referred to as variable interest entities or VIEs) and how to determine if a business enterprise should consolidate the VIEs. This new model for consolidation applies to an entity for which either:

- the equity investors (if any) do not have a controlling financial interest; or
- the equity investment at risk is insufficient to finance the entity s activities without receiving additional subordinated financial support from other parties.

In addition, FIN 46R requires that all enterprises with a significant variable interest in a VIE make additional disclosures regarding their relationship with the VIE. The interpretation requires public entities to apply FIN 46R to all entities that are considered special purpose entities in practice and under the FASB literature that was applied before the issuance of FIN 46R by the end of the first reporting period that ends after December 15, 2003. Application of the accounting requirement of the interpretation to all other entities is required by the end of the first reporting period that ends after March 15, 2004. We do not expect the adoption of FIN 46R to have any effect on our consolidated financial statements.

In April 2003, the FASB issued SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities. SFAS No. 149 amends and clarifies accounting for derivative instruments, including certain derivative instruments embedded in other contracts and hedging activities under SFAS No. 133. The amendments set forth in SFAS No. 149 require that contracts with comparable characteristics be accounted for similarly. SFAS No. 149 is generally effective for contracts entered into or modified after June 30, 2003 (with a few exceptions) and for hedging relationships designated after June 30, 2003. The guidance is to be applied prospectively only. Our adoption of SFAS No. 149 as of July 1, 2003 has had no effect on our consolidated financial statements.

In May 2003, the FASB issued SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity. This statement establishes standards for classification and measurement of certain financial instruments with characteristics of both liabilities and equity on a company s balance sheet. SFAS No. 150 requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances) because that financial instrument embodies an obligation of the issuer. Many of these instruments were previously classified as equity. SFAS No. 150 is effective for financial instruments entered into after May 31, 2003. Our adoption of SFAS No. 150 has had no effect on our consolidated financial statements.

Recent Accounting Developments

SFAS No. 141, Business Combinations, and SFAS No. 142, Goodwill and Other Intangible Assets, were issued by the FASB in June 2001 and became effective for us on July 1, 2001 and January 1, 2002, respectively. SFAS No. 141 requires that all business combinations initiated after June 30, 2001 be accounted for using the purchase method and that certain intangible assets be disaggregated and reported separately from goodwill. SFAS No. 142 established new guidelines for accounting for goodwill and other intangible assets. Under the statement, goodwill and certain other intangible assets are reviewed annually for impairment but are not amortized. To our knowledge, substantially all publicly traded oil and gas companies have continued to include oil and gas rights and interests held under leases, governmental licenses or other contractual arrangements (leasehold interests) as part of oil and gas properties after SFAS No. 141 and SFAS No. 142 became effective. The EITF has added the oil and gas industry s application of SFAS Nos. 141 and 142 to leasehold interests to an upcoming agenda.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Based on our understanding of a potential interpretation, if all leasehold interests were deemed to be intangible assets, for companies like us that use the full cost method of accounting for oil and gas activities:

leasehold interests with proved reserves that were acquired after June 30, 2001 and leasehold interests with no proved reserves would be classified as intangible assets and would not be included in oil and gas properties on our consolidated balance sheet;

our results of operations and cash flows would not be affected because leasehold costs would continue to be amortized in accordance with full cost accounting rules; and

the disclosures required by SFAS Nos. 141 and 142 relative to intangibles would be included in the notes to our financial statements.

If SFAS Nos. 141 and 142 were applied as described above at December 31, 2003 and 2002, we had undeveloped leasehold interests of approximately $112 million and $109 million, respectively (without reduction for depreciation, depletion and amortization) that would be classified on our consolidated balance sheet as intangible undeveloped leaseholds and we had developed leasehold interests of approximately $635 million and $487 million, respectively (without reduction for depreciation, depletion and amortization) that would be classified on our consolidated balance sheet as intangible developed leaseholds. We will continue to classify our leasehold interests as tangible oil and gas properties until further guidance is provided.

2. Discontinued Operations:

On September 5, 2003, we sold our wholly owned subsidiary, Newfield Exploration Australia Ltd., the holding company for all of our Australian assets. We received $9.7 million in proceeds, which was the agreed upon sales price plus estimated working capital at the time of closing. In addition, we recorded a receivable for the barrels in inventory at the time of sale. As of December 31, 2003, this inventory had been lifted and sold by the new owner and the entire receivable of $10.1 million had been collected. We recognized a loss of $9.9 million on the sale.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The historical results of operations of our Australian operations are reflected in our consolidated financial statements as discontinued operations. This reclassification affects not only the 2003 presentation of our consolidated financial statements, but also the presentation of all prior period financial statements. The results of operations of our Australian operations for the twelve months ended December 31, 2003, 2002 and 2001 are summarized as follows:

	Twelve Months Ended December 31,		
	2003	**2002**	**2001**
		(In thousands)	
Revenues	$ 15,485	$ 34,915	$ 35,353
Operating expenses[1]	(21,888)	(29,068)	(29,347)
Income (loss) from operations	(6,403)	5,847	6,006
Other income (expense)[2]	(3,478)	(2,940)	3,273
Income (loss) before income taxes	(9,881)	2,907	9,279
Income tax (provision) benefit[3]	2,784	2,194	(2,885)
Income (loss) from operations	(7,097)	5,101	6,394
Loss on sale	(9,895)		
Income (loss) from discontinued operations	$(16,992)	$ 5,101	$ 6,394

(1) Operating expenses for the year ended December 31, 2003 include the ceiling test writedown of $7.3 million ($5.1 million after-tax) recorded in June 2003.

(2) Other income (expense) primarily consists of foreign currency exchange gains and losses.

(3) In 2002, we realized a one-time tax benefit resulting from revised Australian tax legislation.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The major classes of assets and liabilities of our Australian operations that have been reclassified as discontinued operations as of December 31, 2002 are summarized as follows:

	December 31, 2002
	(In thousands)
Accounts receivable oil and gas	$ 4,819
Inventories	6,650
Other current assets	5,064
Total current assets	16,533
Oil and gas properties, net of accumulated depreciation, depletion and amortization	23,093
Furniture, fixtures and equipment, net	778
Total other assets	23,871
Total assets	$40,404
Accounts payable	$ 591
Accrued liabilities	5,692
Total current liabilities	6,283
Other liabilities	1,027
Deferred taxes	4,532
Total other liabilities	5,559
Total liabilities	$11,842

3. Earnings Per Share:

Basic earnings per share (EPS) is calculated by dividing net income (the numerator) by the weighted average number of shares of common stock outstanding during the period (the denominator). Diluted earnings per share incorporates the incremental shares issuable (if dilutive) upon the assumed exercise of stock options (using the treasury stock method) and upon the assumed conversion of our trust preferred securities as if exercise or conversion to common stock had occurred at the beginning of the accounting period. Net income also has been increased for distributions accrued during the period on our trust preferred securities. We redeemed all of our outstanding trust preferred securities in June 2003. See Note 10, Redemption of Trust Preferred Securities and Note 13, Stock-Based Compensation *Stock Options*.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following is the calculation of basic and diluted weighted average shares outstanding and EPS for each of the years in the three-year period ended December 31, 2003:

	2003	2002	2001
	(In thousands, except share and per share data)		
Income (numerator):			
Income from continuing operations	$ 210,906	$ 68,746	$ 117,354
Income (loss) from discontinued operations, net of tax	(16,992)	5,101	6,394
Income before cumulative effect of change in accounting principle	193,914	73,847	123,748
Cumulative effect of change in accounting principle, net of tax	5,575		(4,794)
Net income basic	199,489	73,847	118,954
After-tax dividends on convertible trust preferred securities	2,978	6,074	6,074
Net income diluted	$ 202,467	$ 79,921	$ 125,028
Weighted average shares (denominator):			
Weighted average shares basic	54,346,686	45,095,619	44,258,018
Dilution effect of stock options outstanding at end of period	475,221	570,416	712,384
Dilution effect of convertible trust preferred securities	1,922,380	3,923,225	3,923,225
Weighted average shares diluted	56,744,287	49,589,260	48,893,627
Earnings per share:			
Basic:			
Income from continuing operations	$ 3.88	$ 1.52	$ 2.65
Income (loss) from discontinued operations	(0.31)	0.12	0.15
Cumulative effect of change in accounting principle, net of tax	0.10		(0.11)
Net income	$ 3.67	$ 1.64	$ 2.69
Diluted:			
Income from continuing operations	$ 3.77	$ 1.51	$ 2.53
Income (loss) from discontinued operations	(0.30)	0.10	0.13
Cumulative effect of change in accounting principle, net of tax	0.10		(0.10)
Net income	$ 3.57	$ 1.61	$ 2.56

The calculation of shares outstanding for diluted EPS for the years ended December 31, 2003, 2002 and 2001 does not include the effect of outstanding stock options to purchase 683,350, 1,087,850 and 907,300 shares, respectively, because to do so would have been antidilutive.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Acquisitions:

Primary Natural Resources Acquisition

On September 5, 2003, we acquired Primary Natural Resources, Inc. (PNR) for approximately $91 million in cash. We acquired PNR primarily to strengthen our position in one of our focus areas the Anadarko and Arkoma Basins of the Mid-Continent.

We accounted for the acquisition as a purchase using the accounting standards established in SFAS No. 141, Business Combinations, and SFAS No. 142, Goodwill and Other Intangible Assets. Our consolidated financial statements include PNR s results of operations subsequent to September 5, 2003. We recorded the estimated fair values of the assets acquired and the liabilities assumed at September 5, 2003, which primarily consisted of oil and gas properties of $94.4 million, a deferred tax liability of $19.7 million and goodwill of $16.4 million. We recorded the deferred tax liability to recognize the difference between the historical tax basis of PNR s assets and the acquisition costs recorded for book purposes. The recorded book value of the proved oil and gas properties was increased and goodwill was recorded to recognize this tax basis differential. Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the purchase. Goodwill is not deductible for tax purposes. See Note 1, Organization and Summary of Significant Accounting Policies *Goodwill*.

EEX Acquisition

On November 26, 2002, we acquired EEX Corporation primarily to further our efforts to expand our onshore operations. The EEX properties are very complementary to our previously existing South Texas property base. The acquisition also accelerated our expansion into deepwater.

Set forth below is the calculation of the EEX purchase price and the allocation of the purchase price to the assets acquired and liabilities assumed based on their relative fair values.

Calculation of purchase price (in thousands):	
Shares of common stock issued	7,104
Stock price(1)	$ 36.348
Fair value of stock issued	$258,216
Debt repaid at closing(2)	222,250
Transaction costs(3)	47,190
Fair value of liabilities at closing:	
Debt(4)	162,441
Other liabilities	52,792
Total purchase price for assets acquired	$742,889
Allocation of purchase price (in thousands):	
Oil and gas properties(5)	$571,502
Floating production system and pipelines(6)	35,000
Deferred tax asset(7)	84,255
Other assets	52,132
Total	$742,889

(1) Represents the average of the closing sales prices for our common stock on five trading days on or around the date the acquisition was first publicly announced.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(2) Represents EEX debt that became due and was repaid at the closing of the acquisition.

(3) Consists primarily of severance costs ($29.7 million), bankers fees ($7.0 million) and other direct transaction costs ($10.5 million). The severance costs resulted from change in control provisions in employment contracts and employee plans.

(4) Represents $100.8 million principal amount of secured notes and $61.6 million related to a forward gas sales contract. See Note 8, Debt.

(5) Proved properties were valued at $483,000 and unproved properties were valued at $88,502.

(6) See Note 5, Oil and Gas Assets *Floating Production System and Pipelines*.

(7) Represents certain tax benefits acquired with EEX primarily consisting of net operating loss carryforwards that we expect to be able to utilize. We have not recognized benefits that are in excess of the annual limitations prescribed by the Internal Revenue Code following a change in corporate ownership.

Lariat Petroleum Acquisition

On January 23, 2001, we acquired Lariat Petroleum, Inc. for approximately $333 million, inclusive of the assumption of debt and certain other obligations of Lariat. The consideration included the issuance of approximately 1.9 million shares of our common stock valued at $68 million. For financial accounting purposes, we allocated $438 million to oil and gas properties, which included a $105 million step-up associated with deferred income taxes.

Pro Forma Results

Our unaudited pro forma results are presented below for the years ended December 31, 2002 and December 31, 2001. The unaudited pro forma results have been prepared to illustrate the effects of the EEX and Lariat acquisitions on our results of operations under the purchase method of accounting as if we had acquired both EEX and Lariat on January 1, 2001.

The unaudited pro forma results do not purport to represent what the results of operations would actually have been if the acquisitions had in fact occurred on such date or to project our results of operations for any future date or period.

	Year Ended December 31,	
	2002	2001
	(Unaudited) (In thousands, except per share data)	
Pro forma:		
Revenue	$799,249	$912,571
Income from operations	179,992	121,149
Income before cumulative effect of change in accounting principle	60,774	55,414
Cumulative effect of change in accounting principle		(4,794)
Net income	60,774	50,620
Basic earnings per common share before cumulative effect of change in accounting principle	$ 1.35	$ 1.08
Basic earnings per common share	1.35	0.98
Diluted earnings per common share before cumulative effect of change in accounting principle	$ 1.33	$ 0.98
Diluted earnings per common share	1.33	0.98

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Oil and Gas Assets:

Oil and Gas Properties

Oil and gas properties consisted of the following at December 31:

	2003	2002	2001
		(In thousands)	
Subject to amortization	$ 3,747,001	$ 3,037,464	$ 2,263,829
Not subject to amortization:			
Exploration wells in progress	8,221	8,212	2,683
Development wells in progress	31,105	6,732	731
Capitalized interest	23,089	14,036	12,184
Other capital costs:			
Incurred in 2003	62,084		
Incurred in 2002	128,962	135,641	
Incurred in 2001	55,135	63,302	80,828
Incurred in 2000 and prior	22,518	33,635	53,112
Total not subject to amortization	331,114	261,558	149,538
Gross oil and gas properties	4,078,115	3,299,022	2,413,367
Accumulated depreciation, depletion and amortization	(1,659,615)	(1,312,110)	(1,018,047)
Net oil and gas properties	$ 2,418,500	$ 1,986,912	$ 1,395,320

We believe that substantially all of the costs not currently subject to amortization will be evaluated within four years.

A portion of incurred (if not previously included in the amortization base) and future development costs associated with qualifying major development projects may be temporarily excluded from amortization. To qualify, a project must require significant costs to ascertain the quantities of proved reserves attributable to the properties under development (e.g., the installation of an offshore production platform from which development wells are to be drilled). Incurred and future costs are allocated between completed and future work. Any temporarily excluded costs are included in the amortization base upon the earlier of when the associated reserves are determined to be proved or impairment is indicated.

As of December 31, 2003, we excluded from the amortization base $25.7 million (which is included in costs not subject to amortization in the table above) associated with development costs for our deepwater Gulf of Mexico project known as Glider, located at Green Canyon 247/248.

Floating Production System and Pipelines

As a result of our acquisition of EEX, we own a 60% interest in a floating production system (FPS), some offshore pipelines and a processing facility located at the end of the pipelines in shallow water. The FPS is a combination deepwater drilling rig and processing facility capable of simultaneous drilling and production operations. These infrastructure assets are not currently in service and we do not have a specific use for them in our offshore operations. At the time of acquisition, we estimated their fair market value to be $35 million and classified them as assets held for sale under the provisions of SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. This statement provides that an asset can only be classified as held for sale for one year. As of December 31, 2003**,** these assets have been re-categorized as held in use assets and will periodically be evaluated for impairment. The costs associated with maintaining these assets

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

are included in operating expenses on our consolidated income statement. Such costs were not significant in 2003 or 2002.

We have engaged brokers who survey the world market for potential application of the assets as is or to-be-modified for a particular application. We also have direct discussions with other operators about the potential application of the assets to their developments around the world. Because there is no established market for these unique assets, it is difficult to accurately estimate their fair market value. An immediate sale or a sale under distressed circumstances might realize less than the current carrying value of the assets.

6. Commodity Derivative Instruments and Hedging Activities:

We utilize swap, floor, collar and three-way collar derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our future oil and gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, their use also may limit future revenues from favorable price movements.

With respect to a swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price for such contract, and we are required to make payment to the counterparty if the settlement price for any settlement period is greater than the swap price for such contract. For a floor contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price for such contract. We are not required to make any payment in connection with the settlement of a floor contract. For a collar contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price for such contract, we are required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price for such contract and neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price for such contract. A three-way collar contract consists of a standard collar contract plus a put sold by us with a price below the floor price of the collar. This additional put requires us to make a payment to the counterparty if the settlement price for any settlement period is below the put price. Combining the collar contract with the additional put results in us being entitled to a net payment equal to the difference between the floor price of the standard collar and the additional put price if the settlement price is equal to or less than the additional put price. If the settlement price is greater than the additional put price, the result is the same as it would have been with a standard collar contract only. This strategy enables us to increase the floor and the ceiling price of the collar beyond the range of a traditional no cost collar while defraying the associated cost with the sale of the additional put.

Substantially all of our oil and gas derivative contracts are settled based upon reported prices on the NYMEX. The estimated fair value of these contracts is based upon various factors, including closing exchange prices on the NYMEX, over-the-counter quotations, volatility and, in the case of collars and floors, the time value of options. The calculation of the fair value of collars and floors requires the use of an option-pricing model.

On the date we enter into a derivative contract, we designate the derivative as a hedge of the variability in cash flows associated with the forecasted sale of our future oil and gas production. After-tax changes in the fair value of a derivative that is highly effective and is designated and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded under the caption Accumulated other comprehensive income (loss) Commodity derivatives on our consolidated balance sheet until the sale of the hedged oil and gas production. Upon the sale of the hedged production, the net after-tax change in the fair value of the associated derivative recorded under the caption Accumulated other comprehensive income (loss) Commodity derivatives is reversed and the gain or loss on the hedge, to the extent that it is effective, is reported in Oil and gas revenues on our consolidated statement of income. At December 31, 2003, we had a net $26.4 million after-tax loss recorded under the caption Accumulated other comprehensive income (loss)

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Commodity derivatives. We expect hedged production associated with commodity derivatives accounting for a net loss of approximately $22.7 million to be sold within the next 12 months and hedged production associated with the remaining net loss of approximately $3.7 million to be sold thereafter. The actual gain or loss on these commodity derivatives could vary significantly as a result of changes in market conditions and other factors.

Any hedge ineffectiveness (which represents the amount by which the change in the fair value of the derivative differs from the change in the cash flows of the forecasted sale of production) is reported currently each period under the caption Commodity derivative income (expense) on our consolidated statement of income.

Prior to January 1, 2002, the periodic changes in the time value component of our collar and floor contracts were treated as ineffective and were reported under the caption Commodity derivative income (expense) on our consolidated statement of income for the period in which the change occurred. On January 1, 2002, we began assessing hedge effectiveness based on the total changes in cash flows on our collar and floor contracts without adjustment for time value as described by DIG Issue G20, Cash Flow Hedges: Assessing and Measuring the Effectiveness of a Purchased Option Used in a Cash Flow Hedge. Pursuant to the guidance in DIG Issue G20, we elected to prospectively record subsequent changes in fair value associated with time value under the caption Accumulated other comprehensive income (loss) Commodity derivatives on our consolidated balance sheet. As a result, amounts recorded in 2002 consist of the reversal of the time value gains that were recognized in 2001 and a diminutive amount representing the ineffective portion of our hedges.

We formally document all relationships between derivative instruments and hedged production, as well as our risk management objective and strategy for particular derivative contracts. This process includes linking all derivatives that are designated as cash flow hedges to the specific forecasted sale of oil or gas at its physical location. We also formally assess (both at the derivative s inception and on an ongoing basis) whether the derivatives being utilized have been highly effective at offsetting changes in the cash flows of hedged production and whether those derivatives may be expected to remain highly effective in future periods. If it is determined that a derivative has ceased to be highly effective as a hedge, we will discontinue hedge accounting prospectively. If hedge accounting is discontinued and the derivative remains outstanding, we will carry the derivative at its fair value on our consolidated balance sheet and recognize all subsequent changes in its fair value on our consolidated statement of income for the period in which the change occurs. Hedge accounting was not discontinued during the periods presented for any hedging instruments.

Although our three-way collar contracts are effective as economic hedges of our commodity price exposure, they do not qualify for hedge accounting under SFAS No. 133. These contracts are carried at their fair value on our consolidated balance sheet under the captions Derivative assets and Derivative liabilities. We recognize all changes in the fair value of our three-way collar contracts on our consolidated statement of income for the period in which the change occurs under the caption Commodity derivative income (expense). Upon realization of gains and losses on our three-way collar contracts, previously recorded unrealized gains and losses will be reversed and realized gains and losses will be recorded under the caption Commodity derivative income (expense). We did not recognize any realized gains or losses on our three-way collar contracts during 2003.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Natural Gas

As of December 31, 2003, we had entered into derivative contracts that qualify as cash flow hedges with respect to our future natural gas production as follows:

		NYMEX Contract Price Per MMBtu							
			Collars						
			Floors		Ceilings		Floor Contracts		Estimated Fair Value
Period and Type of Contract	Volume in MMMBtus	Swaps (Weighted Average)	Range	Weighted Average	Range	Weighted Average	Range	Weighted Average	Asset (Liability) (In millions)
January 2004 - March 2004									
Price swap contracts	13,435	$ 5.42							$ (9.5)
Collar contracts	26,005		$ 3.00 - $5.50	$ 4.96	$ 4.16 - $15.00	$ 8.51			(1.3)
Floor contracts	3,600						$ 4.25 - $5.25	$ 5.24	(0.3)
April 2004 - June 2004									
Price swap contracts	17,565	4.76							(7.1)
Collar contracts	6,345		3.00 - 4.50	4.20	4.16 - 5.85	5.43			(1.4)
Floor contracts	2,250						4.20 - 4.21	4.21	0.2
July 2004 - September 2004									
Price swap contracts	17,275	4.75							(6.6)
Collar contracts	6,345		3.00 - 4.50	4.20	4.16 - 5.85	5.43			(1.7)
Floor contracts	2,250						4.20 - 4.21	4.21	0.3
October 2004 - December 2004									
Price swap contracts	7,645	4.78							(3.2)
Collar contracts	2,445		3.00 - 4.50	4.09	4.16 - 5.85	5.33			(1.0)
Floor contracts	750						4.20 - 4.21	4.21	0.2
January 2005 - December 2005									
Price swap contracts	5,440	4.43							(3.4)
Collar contracts	1,380		3.50	3.50	4.16	4.16			(1.4)
									$ (36.2)

As of December 31, 2003, we also had entered into three-way collar contracts with respect to our future natural gas production as set forth in the table below. These contracts do not qualify for hedge accounting.

NYMEX Contract Price Per MMBtu			
	Collars		
Additional Put	Floors	Ceilings	Estimated Fair Value

Period and Type of Contract	Volume in MMMBtus	Range	Weighted Average	Range	Weighted Average	Range	Weighted Average	Asset (Liability) (In millions)
January 2004 - March 2004								
3-Way collar contracts	2,250	$ 3.65 - $3.70	$ 3.67	$5.25	$ 5.25	$7.00	$ 7.00	$
April 2004 - June 2004								
3-Way collar contracts	6,750	3.50 - 3.76	3.62	4.50 - 4.76	4.62	5.20 - 6.10	5.50	(0.8)
July 2004 - September 2004								
3-Way collar contracts	6,750	3.50 - 3.76	3.62	4.50 - 4.76	4.62	5.20 - 6.10	5.50	(1.2)
October 2004 - December 2004								
3-Way collar contracts	2,250	3.50 - 3.76	3.62	4.50 - 4.76	4.62	5.20 - 6.10	5.50	(0.5)
								$ (2.5)

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Oil

As of December 31, 2003, we had entered into derivative contracts that qualify as cash flow hedges with respect to our future oil production as follows:

		NYMEX Contract Price Per Bbl					
			Collars				
			Floors		Ceilings		
Period and Type of Contract	**Volume in Bbls**	**Swaps (Weighted Average)**	**Range**	**Weighted Average**	**Range**	**Weighted Average**	**Estimated Fair Value Asset (Liability) (In millions)**
January 2004 - March 2004							
Price swap contracts	69,000	$26.86					$(0.4)
Collar contracts	405,000		$22.00 - $24.00	$22.70	$26.04 - $29.70	$27.28	(2.0)
April 2004 - June 2004							
Price swap contracts	24,000	23.23					(0.2)
Collar contracts	300,000		22.00 - 24.00	22.80	26.04 - 28.85	27.16	(1.3)
July 2004 - September 2004							
Price swap contracts	24,000	23.23					(0.1)
Collar contracts	60,000		22.00	22.00	26.35	26.35	(0.2)
October 2004 - December 2004							
Price swap contracts	24,000	23.23					(0.1)
January 2005 - December 2005							
Price swap contracts	204,000	22.63					(0.9)
							$(5.2)

As of December 31, 2003, we also had entered into three-way collar contracts with respect to our future oil production as set forth in the table below. These contracts do not qualify for hedge accounting.

		NYMEX Contract Price Per Bbl					
			Collars				
			Floors		Ceilings		
Period and Type of Contract	**Volume in Bbls**	**Additional Put**	**Range**	**Weighted Average**	**Range**	**Weighted Average**	**Estimated Fair Value Asset (Liability) (In millions)**
January 2004 March 2004							
3-Way collar contracts	286,000	$21.00	$26.00	$26.00	$29.80 - $30.05	$29.98	$(0.7)
April 2004 June 2004							
3-Way collar contracts	377,000	21.00	25.00 - 26.00	25.76	29.70 - 30.05	29.91	(0.7)
July 2004 September 2004							
3-Way collar contracts	379,000	21.00	25.00 - 26.00	25.76	29.70 - 30.05	29.91	(0.5)

October 2004 December 2004							
3-Way collar contracts	379,000	21.00	25.00 - 26.00	25.76	29.70 - 30.05	29.91	(0.4)
January 2005 December 2005							
3-Way collar contracts	90,000	21.00	25.00	25.00	29.70	29.70	(0.1)
							$ (2.4)

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. Accrued Liabilities:

As of the indicated dates, our accrued liabilities consisted of the following:

	December 31, 2003	December 31, 2002
	(In thousands)	
Revenue payable	$ 59,737	$ 45,062
Accrued capital costs	70,464	54,640
Accrued lease operating expenses	20,402	12,381
Employee incentive payable	24,292	13,839
Acquisition transaction costs		42,644
Accrued interest on notes	14,332	18,506
Accrued ad valorem taxes	3,462	2,389
Other	11,365	8,623
Total accrued liabilities	$204,054	$198,084

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Debt:

As of the indicated dates, our long-term debt consisting of the following:

	December 31, 2003	December 31, 2002
	(In thousands)	
Senior unsecured debt:		
Bank revolving credit facility:		
Prime rate based loans	$	$
LIBOR based loans	90,000	28,000
Total bank revolving credit facility	90,000	28,000
Money market lines of credit[1]	5,000	8,000
Total credit arrangements	95,000	36,000
7.45% Senior Notes due 2007	124,821	124,781
Fair value of interest rate swaps[2]	171	
7 5/8% Senior Notes due 2011	174,905	174,895
Fair value of interest rate swaps[2]	449	
Total senior unsecured notes	300,346	299,676
Total senior unsecured debt	395,346	335,676
8 3/8% Senior Subordinated Notes due 2012	248,113	247,971
Secured notes[3]		65,963
Gas sales obligation[1]		60,005
Total long-term debt	$643,459	$709,615

(1) Because capacity under our credit facility was available to repay borrowings under our money market lines of credit and to pay current amounts due under the gas sales obligation as of the indicated dates, these obligations were classified as long-term.

(2) See *Interest Rate Swaps* below.

(3) As of December 31, 2003, the outstanding principal of $2.9 million is classified as current on our consolidated balance sheet because the secured notes were repaid in full in January 2004.

Credit Arrangements

At December 31, 2003, we maintained our reserve-based, senior unsecured revolving credit facility with Chase Manhattan Bank, as agent. The banks participating in the facility have committed to lend us up to $425 million. The amount available under the facility is subject to a calculated borrowing base determined by banks holding 75% of the aggregate commitments. The borrowing base is reduced by the principal amount of any outstanding senior notes ($300 million at December 31, 2003), 30% of the principal amount of any outstanding senior subordinated notes (a reduction of $75 million at December 31, 2003) and the outstanding principal amount of the secured notes ($3 million at December 31, 2003). The borrowing base is redetermined at least semi-annually and, after all required adjustments, was $425 million at December 31, 2003 and $218 million at December 31, 2002. No assurances can be given that the banks will not determine in the future that the borrowing base should be reduced. The facility contains restrictions on the payment of dividends and the incurrence of debt as well as other customary covenants and restrictions. The facility matures on January 23, 2005. We are in the process of replacing the facility.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We also have money market lines of credit with various banks in an amount limited by our credit facility to $40 million. At December 31, 2003, we had outstanding borrowings under our credit facility of $90 million and borrowings under our money market lines of credit of $5 million. Consequently, at December 31, 2003, we had approximately $370 million of available capacity under our credit arrangements.

At December 31, 2003 and 2002, the interest rate was 2.500% and 2.737%, respectively, for LIBOR based loans under our credit facility and 3.0% and 2.615%, respectively, for the loans outstanding under our money market lines of credit. Borrowings outstanding under our credit facility and money market lines of credit are stated at cost, which approximates fair value.

Our current and previous credit facilities provide or provided for the payment of a commitment fee and a standby fee. We paid fees under these facilities of approximately $885,000, $447,000 and $397,000 for the years ended December 31, 2003, 2002 and 2001, respectively.

Senior Notes

On February 22, 2001, we issued $175 million aggregate principal amount of our 7 5/8% Senior Notes due 2011 priced (at 99.931% of par) with a yield to maturity of 7.635%. Net proceeds from the offering (approximately $173.1 million) were used to repay outstanding indebtedness under our credit facility incurred in connection with our January 2001 acquisition of Lariat Petroleum. Interest is payable on each March 1 and September 1, commencing September 1, 2001.

The estimated fair value of our 7.45% Senior Notes due 2007 at December 31, 2003 and 2002 was $133.4 million and $130.1 million, respectively, based on quoted market prices on those dates. The estimated fair value of our 7 5/8% Senior Notes due 2011 at December 31, 2003 and 2002 was $186.2 million and $183.6 million, respectively, based on quoted market prices on those dates.

Our senior notes are unsecured and unsubordinated obligations and rank equally with all of our other existing and future unsecured and unsubordinated obligations. We may redeem some or all of our senior notes at any time before their maturity at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. The indentures governing our senior notes contain covenants that may limit our ability to, among other things, incur debt secured by certain liens, enter into sale/leaseback transactions and enter into merger or consolidation transactions. The indentures also provide that if any of our subsidiaries guarantee any of our indebtedness at any time in the future, then we will cause our senior notes to be equally and ratably guaranteed by that subsidiary.

Senior Subordinated Notes

On August 13, 2002, we issued $250 million aggregate principal amount of our 8 3/8% Senior Subordinated Notes due 2012 priced (at 99.168% of par) with a yield to maturity of 8.50%. The net proceeds from the offering (approximately $241.8 million) were used to repay EEX debt that became due upon EEX s acquisition and to pay transaction costs associated with the acquisition. Because the proceeds were held in escrow pending the closing of the EEX acquisition, interest accruing prior to the closing of approximately $1.6 million was capitalized as a cost of the transaction. The estimated fair value of the 8 3/8% Senior Subordinated Notes due 2012 at December 31, 2003 and 2002 was $272.9 million and $245.0 million, respectively, based on quoted market prices on those dates.

The notes are unsecured senior subordinated obligations that rank junior in right of payment to all of our present and future senior indebtedness. We may redeem some or all of the notes at any time on or after August 15, 2007 at a redemption price stated in the indenture governing the notes. Prior to August 15, 2007, we may redeem all but not part of the notes at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. In addition, before August 15, 2005, we may redeem up to 35% of the original principal amount of the notes with the net cash proceeds of certain sales of our common

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

stock at 108.375% of the principal amount plus accrued and unpaid interest to the date of redemption. The indenture governing the notes limits our ability under certain circumstances to incur additional debt, make restricted payments, pay dividends on or redeem our capital stock, make certain investments, create liens, make certain dispositions of assets, engage in transactions with affiliates and engage in mergers, consolidations and certain sales of assets.

Secured Notes

In the second quarter of 2001, EEX assumed the obligations under the secured notes in connection with the termination of two leveraged leasing arrangements. The notes accrued interest at a rate of 7.54% per year and were secured by the floating production system and pipelines described in Note 5, Oil and Gas Assets *Floating Production System and Pipelines.* Principal was payable in annual installments on January 2 of each year (except 2006) with the final installment due in 2009.

In addition to the scheduled payment of $11.2 million of principal we made during 2003, we also repurchased $63.1 million outstanding principal amount of notes. In January 2004, we repaid the remaining secured notes in full.

Interest Rate Swaps

During September 2003, we entered into interest rate swap agreements to take advantage of low interest rates and to obtain what we view as a more desirable proportion of variable and fixed rate debt. These swap agreements provide for us to pay variable and receive fixed interest payments, and are designated as fair value hedges of a portion of our outstanding senior notes. At December 31, 2003, we had hedged $50 million principal amount of our 7.45% Senior Notes due 2007 and $50 million principal amount of our 7 5/8% Senior Notes due 2011.

Pursuant to SFAS No. 133, changes in the fair value of derivatives designated as fair value hedges are recognized as offsets to the changes in fair value of the exposure being hedged. As a result, the fair value of our interest rate swap agreements is reflected within our derivative assets on our consolidated balance sheet and changes in their fair value are recorded as an adjustment to the carrying value of the associated long-term debt. Receipts and payments related to our interest rate swaps are reflected in interest expense.

Gas Sales Obligation Settlement

Pursuant to a gas forward sales contract entered into in 1999, EEX committed to deliver approximately 50 Bcf of production to Bob West Treasure L.L.C. (BWT) in exchange for proceeds of $105 million. As of the date of our acquisition of EEX, we recorded a liability of approximately $62 million, which represented the then current market value of approximately 16 Bcf of reserves remaining subject to the gas sales contract. We accounted for this obligation as debt on our consolidated balance sheet.

On March 31, 2003, pursuant to a settlement agreement with BWT and the other parties to related transactions, the gas sales contract, the swaps entered into by BWT in connection with the gas sales contract and all other agreements related to the gas sales contract, including the guarantee and all liens and other security interests on EEX s properties, were terminated in exchange for a payment by us of approximately $73 million. This payment represented:

- the remaining unamortized obligation under the gas sales contract;
- the fair market value of swaps entered into by BWT in conjunction with the gas sales contract;

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

various transaction fees related to the termination; and

an agreed upon value for BWT s membership interest in an EEX subsidiary (see Note 9, Minority Interest).

In connection with the settlement, we recognized a loss of $10 million under the caption Gas sales obligation settlement and redemption of securities on our consolidated statement of income.

9. Minority Interest:

In conjunction with EEX entering into the gas sales obligation, BWT acquired a limited membership interest in an EEX subsidiary that owned a substantial portion of EEX s consolidated reserves, a portion of which were subject to the gas sales obligation. We reported this limited membership interest as a minority interest on our consolidated balance sheet at December 31, 2002 based on our estimated price to re-acquire the interest. BWT s limited membership interest was not allocated any earnings and was not entitled to cash distributions. On March 31, 2003, the gas sales obligation and all related financing structures, including the minority interest, were terminated (see Note 8, Debt *Gas Sales Obligation Settlement*).

10. Redemption of Trust Preferred Securities:

We redeemed all of the outstanding 6 1/2% Cumulative Quarterly Income Convertible Preferred Securities of Newfield Financial Trust I on June 27, 2003 for an aggregate redemption price of approximately $148.4 million or $38.31 on a per share of underlying common stock basis (excluding in each case accrued but unpaid distributions). The holders of only a small number of the securities elected to convert their securities into shares of our common stock prior to the redemption date (a total of 48,076 shares of common stock were issued). Included in the aggregate redemption price is $6.5 million of optional redemption premium. Upon redemption, this premium and $4.0 million of unamortized offering costs (which were being amortized over the 30-year life of the securities) were expensed under the caption Gas sales obligation settlement and redemption of securities on our consolidated statement of income.

We financed the redemption with the net proceeds from the issuance and sale of 3.5 million shares of our common stock on May 27, 2003 (approximately $131.2 million, or $37.49 per share) and borrowings under our revolving credit facility.

11. Income Taxes:

Income from continuing operations before income taxes consists of the following:

	For the Year Ended December 31,		
	2003	2002	2001
		(In thousands)	
U.S.	$333,177	$110,062	$182,080
Foreign	(1,558)	(2,087)	
Total	$331,619	$107,975	$182,080

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The total provision (benefit) for income taxes consists of the following:

	For the Year Ended December 31,		
	2003	2002	2001
	(In thousands)		
Current taxes:			
U.S. federal	$ 21,303	$36,811	$29,469
U.S. state	344	691	506
Foreign			
Deferred taxes:			
U.S. federal	95,676	1,751	38,937
U.S. state	3,719	444	(4,186)
Foreign	(329)	(468)	
Total provision for income taxes	$120,713	$39,229	$64,726

The provision for income taxes for each of the years in the three-year period ended December 31, 2003 was different than the amount computed using the federal statutory rate (35%) for the following reasons:

	For the Year Ended December 31,		
	2003	2002	2001
	(In thousands)		
Amount computed using the statutory rate	$116,067	$37,791	$63,728
Increase (decrease) in taxes resulting from:			
State and local income taxes, net of federal effect	2,160	977	1,118
Federal statutory rate in excess of foreign rate	(24)	(100)	
Tax credits and other	2,510	561	(120)
Total provision for income taxes	$120,713	$39,229	$64,726

The components of the deferred tax asset and the deferred tax liability are as follows:

	December 31, 2003			December 31, 2002		
	U.S.	Foreign	Total	U.S.	Foreign	Total
	(In thousands)					
Deferred tax asset:						
Net operating loss carryforwards	$ 82,109	$796	$ 82,905	$ 86,924	$467	$ 87,391
Commodity derivatives	16,607		16,607	18,697		18,697
Other, net	7,875	110	7,985	9,925	110	10,035

Deferred tax asset	106,591	906	107,497	115,546	577	116,123
Deferred tax liability:						
Oil and gas properties	(337,443)		(337,443)	(227,877)		(227,877)
Commodity derivatives						
Net deferred tax liability	(230,852)	906	(229,946)	(112,331)	577	(111,754)
Less net current deferred tax asset	12,893		12,893	13,023		13,023
Noncurrent deferred tax asset (liability)	$ (243,745)	$ 906	$ (242,839)	$ (125,354)	$ 577	$ (124,777)

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2003, we had net operating loss (NOL) carryforwards for federal income tax purposes of approximately $241.3 million that may be used in future years to offset taxable income. Utilization of the NOL carryforwards is subject to annual limitations due to certain stock ownership changes. To the extent not utilized, the NOL carryforwards will begin to expire during the years 2004 through 2023 with a majority expiring in 2019 through 2022. Realization of net operating loss carryforwards is dependent upon generating sufficient taxable income within the carryforward period. Estimates of future taxable income can be significantly affected by changes in natural gas and oil prices, estimates of the timing and amount of future production and estimates of future operating and capital costs.

U.S. deferred taxes have not been provided on foreign income of $44.2 million that is permanently reinvested internationally. We currently do not have any foreign tax credits available to reduce U.S. taxes on this income if it was repatriated.

12. Treasury Stock:

In May 2001, our Board of Directors authorized the expenditure of up to $50 million to repurchase shares of our common stock. We repurchased 823,000 shares in late 2001 for total consideration of $24.7 million at an average of $29.97 per share. In February 2003, our Board of Directors authorized the expenditure of up to $50 million from that date forward to repurchase shares of our common stock. No shares were repurchased under this program. We also repurchase stock in conjunction with our stock-based compensation plans. Such repurchases have not been significant.

13. Stock-Based Compensation:

We have several stock-based compensation plans, which are described below. We apply the intrinsic value method prescribed by APB Opinion No. 25 and related interpretations in accounting for our stock-based compensation plans.

Stock Options

We have granted stock options under several employee stock option and omnibus stock plans. Options that have been granted and are outstanding generally expire ten years from the date of grant and become exercisable at the rate of 20% per year. If additional options are granted under our existing employee plans, the exercise price will not be less than the fair market value per share of our common stock on the date of grant.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following is a summary of all stock option activity for 2001, 2002 and 2003:

	Number of Shares Underlying Options	Weighted Average Exercise Price
Outstanding at December 31, 2000	2,920,160	$20.67
Granted	1,014,750	36.13
Exercised	(274,010)	9.68
Forfeited	(159,150)	31.43
Outstanding at December 31, 2001	3,501,750	25.52
Granted	1,066,700	34.49
Exercised	(391,290)	15.22
Forfeited	(303,570)	32.57
Outstanding at December 31, 2002	3,873,590	28.48
Granted	632,000	35.58
Exercised	(778,370)	19.28
Forfeited	(416,100)	35.39
Outstanding at December 31, 2003	3,311,120	$31.13
Exercisable at December 31, 2001	1,366,325	$16.89
Exercisable at December 31, 2002	1,569,620	$21.47
Exercisable at December 31, 2003	1,414,150	$26.42

The weighted average fair value of an option to purchase one share of common stock granted during 2003, 2002 and 2001 was $14.81, $14.74 and $16.08, respectively. The fair value of each stock option granted is estimated as of the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions.

	2003	2002	2001
Dividend yield	None	None	None
Expected volatility	40.16%	34.15%	34.20%
Risk-free interest rate	3.48%	4.21%	5.0%
Expected option life	6.5 Years	6.5 Years	6.5 Years

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes information about stock options outstanding and exercisable at December 31, 2003:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Shares Underlying Options	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Shares Underlying Options	Weighted Average Exercise Price
$10.94 to $14.78	93,400	2.1 years	$14.06	93,400	$14.06
15.04 to 20.94	264,600	4.5 years	16.96	262,600	16.95
21.06 to 25.00	371,370	4.0 years	22.95	369,570	22.94
25.01 to 29.81	481,700	6.1 years	29.35	262,000	29.27
29.82 to 35.00	1,060,600	8.4 years	33.12	164,700	32.94
35.01 to 50.00	1,039,450	8.1 years	37.99	261,880	38.27
	3,311,120	7.0 years	$31.13	1,414,150	$26.42

Common stock issued upon the exercise of non-qualified stock options results in a tax deduction for us equivalent to the compensation income recognized by the option holder. For financial reporting purposes, the tax effect of this deduction is accounted for as a credit to additional paid-in capital rather than as a reduction of income tax expense. The exercise of stock options during 2003, 2002 and 2001 resulted in a tax benefit to us of approximately $4.9 million, $2.5 million and $2.1 million, respectively.

At December 31, 2003, we had approximately 1,463,384 additional shares available for issuance pursuant to our existing employee plans. As discussed below, our omnibus stock plans also provide for the issuance of restricted shares. Any such issuance would reduce the number of shares available for stock option grants. Of the additional shares available at December 31, 2003, only 98,589 could be granted as restricted shares.

Restricted Shares

At December 31, 2003, there were 384,400 shares of our common stock outstanding that remain subject to forfeiture. These restricted shares fully vest on the ninth anniversary of the date of grant, but vesting may be accelerated if certain performance criteria are met. For a discussion of the number of shares of common stock available for grant to employees as restricted shares, please see the immediately preceding paragraph.

Under our non-employee director restricted stock plan, immediately after each annual meeting of our stockholders each of our directors then in office who has not been an employee of our company at any time since the beginning of the calendar year preceding the calendar year in which the annual meeting is held receives a number of restricted shares determined by dividing $30,000 by the fair market value of one share of our common stock on the date of the annual meeting. The forfeiture restrictions lapse on the day before the first annual meeting of stockholders following the date of issuance of the shares if the holder remains a director until that time. At December 31, 2003, 24,422 shares remain available for grants under this plan.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In accordance with APB Opinion No. 25, we recognize unearned compensation in connection with the grant of restricted shares equal to the fair value of our common stock on the date of grant. As the restricted shares vest, we reduce unearned compensation and recognize compensation expense. The table below sets forth information about our restricted share grants and compensation expense relating to restricted share grants for each of the years in the three-year period ended December 31, 2003.

	Year Ended December 31,		
	2003	2002	2001
Restricted shares granted:			
Employee omnibus plans	265,700	61,500	113,600
Non-employee director plan[1]	6,664	6,296	7,368
Total	272,364	67,796	120,968
Weighted average fair value per restricted share granted	$ 33.32	$ 34.28	$ 36.33
Unearned compensation (in millions)	$ 9.1	$ 2.3	$ 4.4
Restricted shares cancelled:			
Employee omnibus plans	(49,300)	(25,000)	
Non-employee director plan			
Total	(49,300)	(25,000)	
Weighted average fair value per restricted share cancelled	$ 32.09	$ 35.59	
Unearned compensation (in millions)	$ (1.6)	$ (0.9)	
Net unearned compensation (in millions)	$ 7.5	$ 1.4	$ 4.4
Compensation expense (in millions)[2]	$ 3.1	$ 2.8	$ 2.8

(1) Eight directors received grants in each of the years 2003, 2002 and 2001.

(2) As restricted shares vest, the unearned compensation associated with those restricted shares (based on the fair value of our common stock on the date of grant of such restricted shares) is recorded as compensation expense.

Employee Stock Purchase Plan

Pursuant to our employee stock purchase plan, for each six month period beginning on January 1 or July 1 during the term of the plan, each eligible employee has the opportunity to purchase our common stock for a purchase price equal to 85% of the lesser of the fair market value of our common stock on the first day of the period or the last day of the period. No employee may purchase common stock under the plan valued at more than $25,000 in any calendar year. Employees of our foreign subsidiaries are not eligible to participate.

At December 31, 2003, 110,824 shares of common stock were available for issuance pursuant to our stock purchase plan. Under the plan, we sold 30,825 shares in 2003 at a weighted average price of $31.03; 29,410 shares in 2002 at a weighted average price of $30.27; and 28,941 shares in 2001 at a weighted average price of $27.16. In accordance with APB Opinion No. 25 and related interpretations, we have not recognized any compensation expense with respect to the plan.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The weighted average fair value of the option to purchase stock during 2003 was $10.89, during 2002 was $9.85 and during 2001 was $9.86. The fair value of each option granted under the stock purchase plan is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions for grants in 2003, 2002 and 2001:

	2003	2002	2001
Dividend yield	None	None	None
Expected volatility	20.83%	25.24%	25.02%
Risk-free interest rate	1.10%	1.71%	4.36%
Expected option life	6 Months	6 Months	6 Months

14. Pension Plan Obligation:

As part of the EEX acquisition in November 2002, we assumed responsibility for a defined pension benefit plan for current and former employees of EEX and its subsidiaries. This plan has been amended to cease all future retirement benefit accruals, effective March 31, 2003. After March 31, 2003, no participant has earned any further benefit accruals under the plan. The result of this change is that the participant benefits will be frozen at their levels determined as of March 31, 2003 and the benefits will not increase based upon future service completed or compensation received after that date. Accrued pension costs are funded based upon applicable requirements of federal law and deductibility for federal income tax purposes. The components of the pension plan obligation and its funded status are as follows:

	2003	2002
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$(26,423)	$(26,340)
Service cost	(67)	(17)
Interest cost	(1,617)	(139)
Assumption loss due to discount rate change	(2,064)	
Benefits paid	1,066	73
Actuarial gain	868	
Benefit obligation at end of year	$(28,237)	$(26,423)
Change in plan assets:		
Fair value of plan assets at beginning of year	$ 19,867	$ 20,047
Actual return on plan assets	1,552	(112)
Employer contributions	474	5
Benefits paid	(1,066)	(73)
Fair value of plan assets at end of year	$ 20,827	$ 19,867
Obligation and funded status:		
Fair value of plan assets	$ 20,827	$ 19,867
Benefit obligation	(28,237)	(26,423)
Funded status	(7,410)	(6,556)
Unrecognized net loss	1,252	226

Net amount recognized	$ (6,158)	$ (6,330)

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	2003	2002
	(In thousands)	
Amounts recognized on our consolidated balance sheet consist of:		
Prepaid benefit cost	$	$
Accrued benefit cost	(7,715)	(6,330)
Intangible assets	276	
Accumulated other comprehensive loss	1,281	
Net amount recognized	$ (6,158)	$ (6,330)
Components of net periodic benefit cost:		
Service cost	$ 67	$ 17
Interest cost	1,617	139
Expected return on plan assets	(1,383)	(114)
Net periodic benefit cost	$ 301	$ 42
Additional Information:		
Accumulated benefit obligation	$ (28,237)	$ (26,423)
Minimum pension liability	(1,281)	

	2003	2002
The weighted average assumptions used to determine the benefit obligation of the pension plan at December 31 were:		
Discount rate	6.00%	6.50%
Rate of compensation increase	4.00%	4.00%
Cost of living	3.00%	3.00%
The weighted average assumptions used to determine the net periodic pension benefit cost for the years ended December 31 were:		
Discount rate	6.50%	6.50%
Expected long-term rate of return on plan assets	7.00%	7.00%
Rate of compensation increase	4.00%	4.00%
Cost of living	3.00%	3.00%

In developing the assumed overall expected long-term rate of return on assets, we used a building block approach in which rates of return in excess of inflation were considered separately for equity securities, debt securities, real estate and all other assets. The excess returns were weighted by the representative target allocation and added along with an approximate rate of inflation to develop the overall expected long-term rate of return.

We have developed an investment policy to invest in a broad range of securities. The diversified portfolio aims to maximize investment return without exposing it to risk levels above those determined by us. The investment policy takes into consideration the retirement plan s benefit obligations including the expected

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

timing of benefit payments. The following is the allocation of the plan s assets by category at December 31, 2003 and 2002 as well as the target allocation of assets for 2004.

	Target Allocation	Percentage of Plan Assets at December 31	
	2004	2003	2002
Plan Asset Categories:			
Equity securities	40-60%	53.27%	39.32%
Debt securities	40-60%	46.73%	60.01%
Other	0-10%	N/A	0.67%
Total	100%	100.00%	100.00%

During 2004, we anticipate making contributions to the plan of $140,000.

15. Employee Benefit Plans:

Post-Retirement Medical Plan

We sponsor a post-retirement medical plan that covers retired employees until they attain the age of 65. The components of the accrued post-retirement benefit obligation, all of which is unfunded, are as follows:

	2003	2002
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$(2,228)	$ (969)
Service cost	(267)	
Interest cost	(122)	(2)
Participant contributions	(18)	
Assumption loss due to discount rate change	(94)	
Benefits paid	255	68
Actuarial gain or (loss)	244	(1,325)
Benefit obligation at end of year	$(2,230)	$(2,228)
Change in plan assets:		
Fair value of plan assets at beginning of year	$	$
Employer contributions	237	68
Participant contributions	18	
Benefits paid	(255)	(68)
Fair value of plan assets at end of year	$	$

Obligation and funded status:

Fair value of plan assets	$	$
Benefit obligation	(2,230)	(2,228)
Funded status	(2,230)	(2,228)
Unrecognized net loss	1,109	1,325
Net amount recognized	$(1,121)	$ (903)

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	2003	2002
	(In thousands)	
Amounts recognized on our consolidated balance sheet consist of:		
Accrued benefit cost	$(1,121)	$ (903)
Components of net periodic benefit cost:		
Service cost	$ 267	$
Interest cost	122	2
Amortization of net loss	66	
Net periodic benefit cost	$ 455	$ 2
The weighted average assumptions used to determine the benefit obligations at December 31 were:		
Discount rate	6.00%	6.50%
Health care cost trend rate assumed for next year	9.00%	10.00%
Ultimate health care cost trend rate	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2008	2008
The weighted average assumptions used to determine the net periodic benefit cost for the years ended December 31 were:		
Discount rate	6.50%	7.25%
Health care cost trend rate assumed for next year	10.00%	10.00%
Ultimate health care cost trend rate	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2008	2008

Assumed health care cost trend rates effect the amounts reported. A one-percentage-point change in assumed health care cost trend rates would have the following effects (in thousands):

	2003	2002
1-Percentage Point Increase:		
Effect on total of service and interest cost	$ 55	$ 3
Effect on postretirement benefit obligation	$ 201	$ 209
1-Percentage Point Decrease:		
Effect on total of service and interest cost	$ (39)	$ (2)
Effect on postretirement benefit obligation	$ (178)	$ (183)

During 2004, we anticipate making contributions to the plan of $197,000 and the participants are expected to contribute approximately $13,000.

Incentive Compensation Plan

Effective January 1, 2003, our Board of Directors adopted our 2003 Incentive Compensation Plan and terminated the ability to grant any further awards pursuant to our 1993 Incentive Compensation Plan. Our new incentive plan provides for the creation each calendar year of an award pool that is generally equal to 5% of our adjusted net income (as defined in the plan) plus the revenues attributable to an overriding royalty interest bearing on the interests of investors that participate in certain of our activities. Both of the incentive plans are administered by the Compensation & Management Development Committee of our Board of Directors and award amounts are (or, in the case of the 1993 plan, were) recommended by our chief executive officer. All employees are (or were) eligible for awards if employed on both October 1 and December 31 of the performance period. Awards under both of our incentive plans may (or could), and generally do (or did), have both a current and a deferred component. Deferred awards are paid in four annual installments, each

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

installment consisting of 25% of the deferred award, plus interest on awards paid in cash (all deferred awards under the 2003 plan are paid in cash). Total expense under our 2003 incentive plan for the year ended December 31, 2003 was $20.2 million.

The 1993 plan is very similar to the new plan. Under the 1993 plan, the incentive pool generally equaled the revenues that would be attributable to a 1% overriding royalty interest on acquired producing properties and a 2% overriding royalty interest on exploration properties, bearing on both our interest and the interests of certain investors that participated in our activities on such properties. If, for a particular year, the portion of the pool that related to our interests was in excess of 5% of our adjusted net income (as defined in the plan) for that year, such excess could not be awarded to employees. In addition, under the 1993 plan a participant could elect for all or a portion of his or her deferred award to be paid in our common stock instead of cash. In such case, the number of shares of common stock to be awarded was determined by using the fair market value of our common stock on the date of the award. Total expense under the 1993 incentive plan for the years ended December 31, 2002 and 2001 was $10.1 million and $11.6 million, respectively.

401(k) Plan

We sponsor a 401(k) profit sharing plan under Section 401(k) of the Internal Revenue Code. This plan covers all of our employees other than employees of our foreign subsidiaries. We match $1.00 for each $1.00 of employee deferral, with our contribution not to exceed 8% of an employee s salary, subject to limitations imposed by the Internal Revenue Service. Our contributions to the 401(k) plan totaled $1.7 million, $1.5 million and $1.3 million for the years ended December 31, 2003, 2002 and 2001, respectively.

Deferred Compensation Plan

During 1997, we implemented a highly compensated employee deferred compensation plan. This non-qualified plan allows an eligible employee to defer a portion of his or her salary or bonus on an annual basis. We match $1.00 for each $1.00 of employee deferral, with our contribution not to exceed 8% of an employee s salary, subject to limitations imposed by the plan. Our contribution with respect to each participant in the deferred compensation plan is reduced by the amount of contribution made by us to our 401(k) plan for that participant. Our contributions to the deferred compensation plan totaled $32,500, $32,000 and $32,000 for the years ended December 31, 2003, 2002 and 2001, respectively.

16. Commitments and Contingencies:

Lease Commitments

Rent expense with respect to our lease commitments for the years ended December 31, 2003, 2002 and 2001 was $4.0 million, $4.8 million and $4.1 million, respectively. We are obligated under non-cancellable operating leases for our office space in Houston, Texas and Tulsa, Oklahoma. Future minimum payments required under our office leases as of December 31, 2003 are as follows (in thousands):

Year Ending December 31,	
2004	$ 3,756
2005	3,842
2006	3,447
2007	3,471
2008	2,836
Total minimum lease payments	$ 17,352

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Litigation

We have been named as a defendant in a number of lawsuits arising in the ordinary course of our business. While the outcome of these lawsuits cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations.

17. Stockholder Rights Plan:

In 1999, we adopted a stockholder rights plan. The plan is designed to ensure that all of our stockholders receive fair and equal treatment if a takeover of our company is proposed. It includes safeguards against partial or two-tiered tender offers, squeeze-out mergers and other abusive takeover tactics.

The plan provides for the issuance of one right for each outstanding share of our common stock. The rights will become exercisable only if a person or group acquires 20% or more of our outstanding voting stock or announces a tender or exchange offer that would result in ownership of 20% or more of our voting stock.

Each right will entitle the holder to buy one one-thousandth (1/1000) of a share of a new series of junior participating preferred stock at an exercise price of $85 per right, subject to antidilution adjustments. Each one one-thousandth of a share of this new preferred stock has the dividend and voting rights of, and is designed to be substantially equivalent to, one share of our common stock. Our Board of Directors may, at its option, redeem all rights for $0.01 per right at any time prior to the acquisition of 20% or more of our outstanding voting stock by a person or group.

If a person or group acquires 20% or more of our outstanding voting stock, each right will entitle holders, other than the acquiring party, to purchase shares of our common stock having a market value of $170 for a purchase price of $85, subject to antidilution adjustments.

The plan also includes an exchange option. If a person or group acquires 20% or more, but less than 50%, of our outstanding voting stock, our Board of Directors may, at its option, exchange the rights in whole or part for shares of our common stock. Under this option, we would issue one share of our common stock, or one one-thousandth of a share of new preferred stock, for each two shares of our common stock for which a right is then exercisable. This exchange would not apply to rights held by the person or group holding 20% or more of our voting stock.

If, after the rights have become exercisable, we merge or otherwise combine with another entity, or sell assets constituting more than 50% of our assets or producing more than 50% of our earning power or cash flow, each right then outstanding will entitle its holder to purchase for $85, subject to antidilution adjustments, a number of the acquiring party s common shares having a market value of twice that amount.

The plan will not prevent, nor is it intended to prevent, a takeover of our company. Since the rights may be redeemed by our Board of Directors under certain circumstances, they should not interfere with any merger or other business combination approved by our Board. The issuance of the rights does not in any way diminish our financial strength or interfere with our business plans. The issuance of the rights has no dilutive effect, does not affect reported earnings per share or change the way our common stock is currently traded.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

18. Geographic Information:

	United States	International	Total
		(In thousands)	
Year Ended December 31, 2003:			
Oil and gas revenues	$1,016,814	$ 172	$1,016,986
Operating expenses:			
Lease operating	119,225	65	119,290
Production and other taxes	31,737		31,737
Transportation	6,359		6,359
Depreciation, depletion and amortization	394,450	251	394,701
Allocated income taxes	162,765	(58)	
Net income (loss) from oil and gas operations	$ 302,278	$ (86)	
Gas sales obligation settlement and redemption of securities			20,475
General and administrative (inclusive of stock compensation)(1)			61,636
Total operating expenses			634,198
Income from operations			382,788
Interest expense and dividends, net of interest income, capitalized interest and other			(45,067)
Commodity derivative expense			(6,102)
Income from continuing operations before income taxes			$ 331,619
Total long-lived assets	$2,365,158	$53,342	$2,418,500
Additions to long-lived assets(2)	$ 762,016	$17,077	$ 779,093

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	United States	International	Total
		(In thousands)	
Year Ended December 31, 2002:			
Oil and gas revenues	$ 626,835	$	$ 626,835
Operating expenses:			
Lease operating	90,768		90,768
Production and other taxes	13,285		13,285
Transportation	5,708		5,708
Depreciation, depletion and amortization	295,054		295,054
Allocated income taxes	77,707		
Net income from oil and gas operations	$ 144,313	$	
General and administrative (inclusive of stock compensation)[1]			54,363
Total operating expenses			459,178
Income from operations			167,657
Interest expense and dividends, net of interest income, capitalized interest and other			(30,535)
Commodity derivative expense			(29,147)
Income from continuing operations before income taxes			$ 107,975
Total long-lived assets	$ 1,950,568	$ 36,344	$ 1,986,912
Additions to long-lived assets	$ 880,326	$ 8,156	$ 888,482

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	United States	International	Total
		(In thousands)	
Year Ended December 31, 2001:			
Oil and gas revenues	$ 714,052	$	$ 714,052
Operating expenses:			
Lease operating	85,683		85,683
Production and other taxes	14,424		14,424
Transportation	5,569		5,569
Depreciation, depletion and amortization	274,893		274,893
Ceiling test writedown	106,011		106,011
Allocated income taxes	79,616		
Net income from oil and gas operations	$ 147,856	$	
General and administrative (inclusive of stock compensation)[1]			42,621
Total operating expenses			529,201
Income from operations			184,851
Interest expense and dividends, net of interest income, capitalized interest and other			(27,592)
Commodity derivative income			24,821
Income from continuing operations before income taxes			$ 182,080
Total long-lived assets	$1,367,132	$28,188	$1,395,320
Additions to long-lived assets	$ 939,588	$11,944	$ 951,532

(1) General and administrative expense includes stock compensation charges of $3,059, $2,801 and $2,751 for the years ended December 31, 2003, 2002 and 2001, respectively.

(2) Includes $131.2 million (domestic) and $1.1 million (international) for asset retirement obligations associated with our adoption of SFAS No. 143.

19. Supplemental Cash Flow Information:

	Year Ended December 31,		
	2003	2002	2001
		(In thousands)	
Cash payments:			
Interest and dividend payments, net of interest capitalized of $15,943, $8,839 and $8,891 during 2003, 2002 and 2001, respectively	$ 41,732	$ 35,502	$ 33,427
Income tax payments	39,993	21,520	41,384

Non-cash items excluded from the statement of cash flows:			
Accrued capital expenditures	$ (22,913)	$ (17,132)	$ (26,198)
Asset retirement costs	(132,345)		
Stock issued for acquisitions		(258,216)	(67,853)
Other	(68)	(121)	(484)

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

20. Related Party Transactions:

Three private equity funds (the WP funds) managed by Warburg Pincus LLC (WP LLC) held all of the outstanding preferred stock of EEX prior to our acquisition of EEX in November 2002 and received an aggregate of 4,700,000 shares of our common stock in exchange for their EEX preferred stock in the acquisition. Concurrently with the execution of the merger agreement to acquire EEX, we entered into a registration rights agreement and a voting agreement with the WP funds. Pursuant to the registration rights agreement, we filed a shelf registration statement under the Securities Act to register the reoffer and resale of the shares of our common stock received by the WP funds in the acquisition. We are required to maintain the effectiveness of the registration statement until all of the shares of our common stock received by the WP funds in the acquisition have been sold or until such time as such shares are eligible for resale under Rule 144(k) under the Securities Act. In addition, if we propose to file a registration statement or a prospectus supplement to an already effective shelf registration statement with respect to an underwritten public offering of our common stock, the WP funds have the right to include their shares of our commons stock in the registration, subject to certain limitations.

The sole general partner of each of the WP funds is Warburg, Pincus & Co. (WP & Co.). WP LLC manages WPV. Howard H. Newman, one of our directors, is a general partner of WP & Co and a Vice Chairman, Managing Director and member of WP LLC. Mr. Newman also was a director of EEX prior to its acquisition.

Terry Huffington, a former director of our company, is a principal owner of Huffco International L.L.C. and David A. Trice, our President and Chief Executive Officer, is a minority owner of Huffco. In May 1997, prior to Ms. Huffington and Mr. Trice becoming affiliated with us, we acquired from Huffco an entity now known as Newfield China, LDC, the owner of a 35% interest (subject to a 51% reversionary interest held by the Chinese government) in a production sharing contract area, referred to as Block 05/36, in the Bohai Bay, offshore China. Huffco retained preferred shares of Newfield China that provide for an aggregate dividend equal to 10% of the excess of proceeds received by Newfield China from the sale of oil, gas and other minerals over all costs incurred with respect to exploration and production in Block 05/36, plus the cash purchase price we paid Huffco for Newfield China ($6.2 million). At December 31, 2003, Newfield China had approximately $42 million in unrecovered costs, no proved reserves and no revenue and, as a result, no dividends have been paid to date on its preferred shares.

NEWFIELD EXPLORATION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

21. Quarterly Results of Operations (Unaudited):

The results of operations by quarter for the years ended December 31, 2003 and 2002 are as follows:

	2003 Quarter Ended			
	March 31	June 30	September 30	December 31
	(In thousands, except per share data)			
Oil and gas revenues	$267,891	$255,552	$248,664	$244,879
Income from operations	107,992	94,455	93,757	86,583
Income from continuing operations	59,346	53,055	58,351	40,154
Loss from discontinued operations, net of tax	(780)	(7,240)	(8,972)	
Cumulative effect of change in accounting principle, net of tax	5,575			
Net income	64,141	45,815	49,379	40,154
Basic earnings per common share(1):				
Income from continuing operations	$ 1.14	$ 0.99	$ 1.04	$ 0.72
Loss from discontinued operations	(0.01)	(0.13)	(0.16)	
Cumulative effect of change in accounting principle, net of tax	0.11			
Basic earnings per common share	$ 1.24	$ 0.86	$ 0.88	$ 0.72
Diluted earnings per common share(1):				
Income from continuing operations	$ 1.08	$ 0.95	$ 1.04	$ 0.71
Loss from discontinued operations	(0.01)	(0.13)	(0.16)	
Cumulative effect of change in accounting principle, net of tax	0.10			
Diluted earnings per common share	$ 1.17	$ 0.82	$ 0.88	$ 0.71

	2002 Quarter Ended			
	March 31	June 30	September 30	December 31
	(In thousands, except per share data)			
Oil and gas revenues	$141,473	$154,475	$141,978	$188,909
Income from operations	35,131	37,504	32,903	62,119
Income from continuing operations	16,839	15,471	7,639	28,797
Income (loss) from discontinued operations, net of tax	(513)	799	1,732	3,083
Net income	16,326	16,270	9,371	31,880
Basic earnings per common share(1):				
Income from continuing operations	$ 0.38	$ 0.35	$ 0.17	$ 0.61
Income (loss) from discontinued operations	(0.01)	0.02	0.04	0.07
Basic earnings per common share	$ 0.37	$ 0.37	$ 0.21	$ 0.68

Diluted earnings per common share[1]:				
Income from continuing operations	$ 0.38	$ 0.34	$ 0.17	$ 0.59
Income (loss) from discontinued operations	(0.01)	0.02	0.04	0.06
Diluted earnings per common share	$ 0.37	$ 0.36	$ 0.21	$ 0.65

(1) The sum of the individual quarterly earnings (loss) per share may not agree with year-to-date earnings (loss) per share as each quarterly computation is based on the income or loss for that quarter and the weighted average number of shares outstanding during that quarter.

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED

Costs incurred for oil and gas property acquisition, exploration and development activities for each of the years in the three-year period ended December 31, 2003 are as follows (in thousands):

	United States	China	United Kingdom	Other Foreign	Total
2003:					
Property acquisition:					
Unproved	$ 38,526	$ 840	$ 3,878	$ 1,087	$ 44,331
Proved	137,198		2,885		140,083
Exploration	145,832	4,195	2,302	741	153,070
Development	293,338				293,338
Asset retirement cost(1)	30,618		1,149		31,767
Capitalized interest	15,926				15,926
Total costs incurred	$ 661,438	$ 5,035	$ 10,214	$ 1,828	$ 678,515
2002:					
Property acquisition:					
Unproved	$ 112,231	$	$	$	$ 112,231
Proved	511,340				511,340
Exploration	100,941	4,877	1,388	1,891	109,097
Development	146,975				146,975
Capitalized interest	8,839				8,839
Total costs incurred	$ 880,326	$ 4,877	$ 1,388	$ 1,891	$ 888,482
2001:					
Property acquisition:					
Unproved	$ 57,872	$	$	$	$ 57,872
Proved	482,613				482,613
Exploration	91,991	10,901		1,043	103,935
Development	298,221				298,221
Capitalized interest	8,891				8,891
Total costs incurred	$ 939,588	$ 10,901	$	$ 1,043	$ 951,532

(1) Excludes $100.6 million of cumulative asset retirement cost recorded upon the adoption of the provisions of SFAS No. 143 on January 1, 2003.

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

Capitalized costs for our oil and gas producing activities consist of the following at the end of each of the years in the three-year period ended December 31, 2003 (in thousands):

	United States	China	United Kingdom	Other Foreign	Total
2003:					
Proved properties	$ 3,782,293	$	$ 4,034	$	$ 3,786,327
Unproved properties	242,401	35,049	7,568	6,770	291,788
	4,024,694	35,049	11,602	6,770	4,078,115
Accumulated depreciation, depletion and amortization	(1,659,536)		(79)		(1,659,615)
Net capitalized cost	$ 2,365,158	$ 35,049	$ 11,523	$ 6,770	$ 2,418,500
2002:					
Proved properties	$ 3,052,408	$	$	$	$ 3,052,408
Unproved properties	210,270	30,014	1,388	4,942	246,614
	3,262,678	30,014	1,388	4,942	3,299,022
Accumulated depreciation, depletion and amortization	(1,312,110)				(1,312,110)
Net capitalized cost	$ 1,950,568	$ 30,014	$ 1,388	$ 4,942	$ 1,986,912
2001:					
Proved properties	$ 2,268,372	$	$	$	$ 2,268,372
Unproved properties	116,807	25,137		3,051	144,995
	2,385,179	25,137		3,051	2,413,367
Accumulated depreciation, depletion and amortization	(1,018,047)				(1,018,047)
Net capitalized cost	$ 1,367,132	$ 25,137	$	$ 3,051	$ 1,395,320

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

Users of this information should be aware that the process of estimating quantities of proved and proved developed natural gas and crude oil reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time.

Estimated Net Quantities of Proved Oil and Gas Reserves

The following table sets forth our total net proved reserves and our total net proved developed reserves as of December 31, 2000, 2001, 2002 and 2003 and the changes in our total net proved reserves during the three-year period ended December 31, 2003, as estimated by our petroleum engineering staff:

	Oil, condensate and Natural Gas Liquids (MBbls)			Natural Gas (MMcf)			Total (MMcfe)		
	U.S.	U.K.	Total	U.S.	U.K.	Total	U.S.	U.K.	Total
Proved developed and undeveloped reserves as of:									
December 31, 2000	22,551		22,551	519,723		519,723	655,029		655,029
Revisions of previous estimates	(714)		(714)	(18,725)		(18,725)	(23,009)		(23,009)
Extensions, discoveries and other additions	4,365		4,365	115,433		115,433	141,623		141,623
Purchases of properties	10,279		10,279	235,048		235,048	296,722		296,722
Sales of properties									
Production	(5,522)		(5,522)	(133,167)		(133,167)	(166,299)		(166,299)
December 31, 2001	30,959		30,959	718,312		718,312	904,066		904,066
Revisions of previous estimates	1,367		1,367	528		528	8,730		8,730
Extensions, discoveries and other additions	4,218		4,218	108,201		108,201	133,509		133,509
Purchases of properties	4,191		4,191	301,614		301,614	326,760		326,760
Sales of properties	(1,463)		(1,463)	(6,880)		(6,880)	(15,658)		(15,658)
Production	(5,235)		(5,235)	(144,660)		(144,660)	(176,070)		(176,070)
December 31, 2002	34,037		34,037	977,115		977,115	1,181,337		1,181,337
Revisions of previous estimates	663		663	(4,223)		(4,223)	(239)		(239)
Extensions, discoveries and other additions	6,267		6,267	200,382		200,382	237,970		237,970
Purchases of properties	2,835	26	2,861	101,344	2,517	103,861	118,365	2,673	121,038
Sales of properties				(2,762)		(2,762)	(2,762)		(2,762)
Production	(6,054)		(6,054)	(184,188)	(45)	(184,233)	(220,513)	(45)	(220,558)
December 31, 2003	37,748	26	37,774	1,087,668	2,472	1,090,140	1,314,158	2,628	1,316,786

Proved developed reserves as of:									
December 31, 2000	18,657		18,657	416,368		416,368	528,310		528,310
December 31, 2001	29,151		29,151	662,879		662,879	837,785		837,785
December 31, 2002	32,425		32,425	905,062		905,062	1,099,612		1,099,612
December 31, 2003	30,688	26	30,714	955,760	2,472	958,232	1,139,893	2,628	1,142,521

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following information was developed utilizing procedures prescribed by SFAS No. 69, Disclosures about Oil and Gas Producing Activities. The information is based on estimates prepared by our petroleum engineering staff. The standardized measure of discounted future net cash flows should not be viewed as representative of our current value. It and the other information contained in the following tables may be useful for certain comparative purposes, but should not be solely relied upon in evaluating us or our performance.

We believe that in reviewing the information that follows the following factors should be taken into account:

future costs and selling prices will probably differ from those required to be used in these calculations;

actual rates of production achieved in future years may vary significantly from the rates of production assumed in the calculations;

a 10% discount rate may not be reasonable as a measure of the relative risk inherent in realizing future net oil and gas revenues; and

future net revenues may be subject to different rates of income taxation.

Under the standardized measure, future cash inflows were estimated by applying year-end oil and gas prices, adjusted for location and quality differences, to the estimated future production of year-end proved reserves. Future cash inflows do not reflect the impact of future production that is subject to open hedge positions (see Note 6, Commodity Derivative Instruments and Hedging Activities).Future cash inflows were reduced by estimated future development, abandonment and production costs based on year-end costs in order to arrive at net cash flows before tax. Future income tax expense has been computed by applying year-end statutory tax rates to aggregate future pre-tax net cash flows reduced by the tax basis of the properties involved and tax carryforwards. Use of a 10% discount rate and year-end prices and costs are required by SFAS No. 69.

In general, management does not rely on the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

The standardized measure of discounted future net cash flows from our estimated proved oil and gas reserves is as follows:

	U.S.	U.K.	Total
		(In thousands)	
2003:			
Future cash inflows	$ 7,617,635	$ 11,839	$ 7,629,474
Less related future:			
Production costs	(1,374,244)	(5,625)	(1,379,869)
Development and abandonment costs	(449,624)	(1,511)	(451,135)
Future net cash flows before income taxes	5,793,767	4,703	5,798,470
Future income tax expense	(1,461,000)	(1,881)	(1,462,881)
Future net cash flows before 10% discount	4,332,767	2,822	4,335,589
10% annual discount for estimating timing of cash flows	(1,399,999)	(151)	(1,400,150)
Standardized measure of discounted future net cash flows	$ 2,932,768	$ 2,671	$ 2,935,439
2002:			
Future cash inflows	$ 5,633,523	$	$ 5,633,523
Less related future:			
Production costs	(1,066,354)		(1066,354)
Development and abandonment costs	(299,560)		(299,560)
Future net cash flows before income taxes	4,267,609		4,267,609
Future income tax expense	(1,042,310)		(1,042,310)
Future net cash flows before 10% discount	3,225,299		3,225,299
10% annual discount for estimating timing of cash flows	(978,339)		(978,339)
Standardized measure of discounted future net cash flows	$ 2,246,960	$	$ 2,246,960
2001:			
Future cash inflows	$ 2,446,106	$	$ 2,446,106
Less related future:			
Production costs	(616,863)		(616,863)
Development and abandonment costs	(244,685)		(244,685)
Future net cash flows before income taxes	1,584,558		1,584,558
Future income tax expense	(272,936)		(272,936)
Future net cash flows before 10% discount	1,311,622		1,311,622
	(352,759)		(352,759)

10% annual discount for estimating timing of cash flows			
Standardized measure of discounted future net cash flows	$ 958,863	$	$ 958,863

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

Set forth in the table below is a summary of the changes in the standardized measure of discounted future net cash flows for our proved oil and gas reserves during each of the years in the three-year period ended December 31, 2003:

	U.S.	U.K.	Total
		(In thousands)	
2003:			
Beginning of the period	$2,246,960	$	$2,246,960
Revisions of previous estimates:			
Changes in prices and costs	575,791		575,791
Changes in quantities	(143)		(143)
Development costs incurred during the period	63,409		63,409
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	710,644		710,644
Purchases and sales of reserves in place, net	295,775	3,846	299,621
Accretion of discount	224,696		224,696
Sales of oil and gas, net of production costs	(852,375)	(107)	(852,482)
Net change in income taxes	(246,239)	(1,068)	(247,307)
Production timing and other	(85,750)		(85,750)
Net increase	685,808	2,671	688,479
End of the period	$2,932,768	$ 2,671	$2,935,439
2002:			
Beginning of the period	$ 958,863	$	$ 958,863
Revisions of previous estimates:			
Changes in prices and costs	1,046,860		1,046,860
Changes in quantities	12,341		12,341
Development costs incurred during the period	31,889		31,889
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	420,846		420,846
Purchases and sales of reserves in place, net	663,612		663,612
Accretion of discount	95,886		95,886
Sales of oil and gas, net of production costs	(347,810)		(347,810)
Net change in income taxes	(769,374)		(769,374)
Production timing and other	133,847		133,847
Net increase	1,288,097		1,288,097
End of the period	$2,246,960	$	$2,246,960

NEWFIELD EXPLORATION COMPANY

SUPPLEMENTARY FINANCIAL INFORMATION

SUPPLEMENTARY OIL AND GAS DISCLOSURES UNAUDITED (Continued)

	U.S.	U.K.	Total
		(In thousands)	
2001:			
Beginning of the period	$ 2,653,353	$	$ 2,653,353
Revisions of previous estimates:			
Changes in prices and costs	(2,372,021)		(2,372,021)
Changes in quantities	(9,536)		(9,536)
Development costs incurred during the period	72,016		72,016
Additions to proved reserves resulting from extensions, discoveries and improved recovery, less related costs	187,793		187,793
Purchases of reserves in place	267,925		267,925
Accretion of discount	265,335		265,335
Sales of oil and gas, net of production costs	(1,206,548)		(1,206,548)
Net change in income taxes	922,071		922,071
Production timing and other	178,475		178,475
Net decrease	(1,694,490)		(1,694,490)
End of the period	$ 958,863	$	$ 958,863

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

On January 28, 2004, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended), which have been designed to permit us to effectively identify and timely disclose important information. Based on this evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of the end of the period covered by this report such that the information relating to Newfield, including our consolidated subsidiaries, required to be disclosed in our SEC reports (i) is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and (ii) is accumulated and communicated to Newfield s management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

During the three months ended December 31, 2003, we made no changes in our internal control over financial reporting or in other factors that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Pursuant to Section 906 of The Sarbanes-Oxley Act of 2002, our chief executive officer and chief financial officer have provided certain certifications to the SEC. These certifications accompanied this report when filed with the SEC, but are not set forth herein.

PART III

Item 10. ***Directors and Executive Officers of the Registrant***

The information required by Item 10 is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2004 Annual Meeting of Stockholders to be held on May 6, 2004 and to the information set forth in Item 4A, Executive Officers, in this report.

Corporate Code of Business Conduct and Ethics

We have adopted a corporate code of business conduct and ethics for directors, officers (including our principal executive officer, principal financial officer and controller or principal accounting officer) and employees. Our corporate code includes a financial code of ethics applicable to our chief executive officer, chief financial officer and controller or chief accounting officer. Both of these codes are available on our website at http://www.newfld.com/ Corporate Governance/ Overview. Stockholders may request a free copy of these codes from:

Newfield Exploration Company
Attention: Investor Relations
363 North Sam Houston Parkway East, Suite 2020
Houston, Texas 77060
(281) 405-4284
http://www.newfld.com/ Investor Relations/ Information Request.

Corporate Governance Guidelines

We have adopted corporate governance guidelines, which are available on our website at http://www.newfld.com/ Corporate Governance/ Overview/ Guidelines for Corporate Governance. Stockholders may request a free copy of our corporate governance guidelines from the address and phone number set forth above under Corporate Code of Business Conduct and Ethics.

Committee Charters

The charters of the Audit Committee, the Compensation & Management Development Committee and the Nominating & Corporate Governance Committee of our Board of Directors are available on our website at http://www.newfld.com/CorporateGovernance/Overview. Stockholders may request a free copy of any of these charters from the address and phone number set forth above under Corporate Code of Business Conduct and Ethics.

Section 16(a) Beneficial Ownership Reporting Compliance

Information regarding Section 16(a) beneficial ownership reporting compliance is set forth under Common Stock Ownership of Certain Beneficial Owners and Management Section 16(a) Beneficial Ownership Reporting Compliance in our definitive Proxy Statement, which information is incorporated herein by reference.

Item 11. ***Executive Compensation***

The information required by Item 11 is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2004 Annual Meeting of Stockholders to be held on May 6, 2004.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

The information required by Item 12 is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2004 Annual Meeting of Stockholders to be held on May 6, 2004.

Item 13. ***Certain Relationships and Related Transactions***

The information required by Item 13 is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2004 Annual Meeting of Stockholders to be held on May 6, 2004.

Item 14. ***Principal Auditor Fees and Services***

The information required by Item 14 is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2004 Annual Meeting of Stockholders to be held on May 6, 2004.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules and Reports on Form 8-K***

(a) *Financial Statements, Financial Statement Schedules and Exhibits*

(1) *Financial Statements:* Reference is made to the index set forth on page 47 of this report.

(2) *Financial Statement Schedules:* Financial statement schedules listed under SEC rules but not included in this report are omitted because they are not applicable or the required information is provided in the notes to our consolidated financial statements.

(3) *Index of Exhibits:* See Index of Exhibits below for a list of those exhibits filed herewith or incorporated herein by reference.

(b) *Reports on Form 8-K*

On October 15, 2003, we filed a Current Report on Form 8-K reporting the issuance of our @NFX publication, which included a summary of our natural gas and crude oil hedge positions as of October 14, 2003.

On October 30, 2003, we filed a Current Report on Form 8-K announcing the 2004 production estimate disclosed in our third quarter 2003 financial and operating results conference call.

On October 30, 2003, we filed a Current Report on Form 8-K in connection with the announcement of our third quarter and year-to-date 2003 financial results and fourth quarter 2003 guidance regarding production and significant operating and financial data.

On December 15, 2003, we filed a Current Report on Form 8-K announcing the temporary suspension of trading under our 401(k) plan.

(c) *Index of Exhibits*

3. Exhibits

Exhibit Number	Title
3.1	Second Restated Certificate of Incorporation of Newfield (incorporated by reference to Exhibit 3.1 to Newfield s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 1-12534))
3.1.1	Certificate of Amendment to Second Restated Certificate of Incorporation of Newfield dated May 15, 1997 (incorporated by reference to Exhibit 3.1.1 to Newfield s Registration Statement on Form S-3 (Registration No. 333-32582))
3.2	Restated Bylaws of Newfield as amended by Amendment No. 1 thereto adopted January 31, 2000 (incorporated by reference to Exhibit 3.3 to Newfield s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 1-12534))
3.4	Certificate of Designation of Series A Junior Participating Preferred Stock, par value $0.01 per share, setting forth the terms of the Series A Junior Participating Preferred Stock, par value $0.01 per share (incorporated by reference to Exhibit 3.5 to Newfield s Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 1-12534))
4.1	Rights Agreement, dated as of February 12, 1999, between Newfield and ChaseMellon Shareholder Services L.L.C., as Rights Agent, specifying the terms of the Rights to Purchase Series A Junior Participating Preferred Stock, par value $0.01 per share, of Newfield (incorporated by reference to Exhibit 1 to Newfield s Registration Statement on Form 8-A filed with the SEC on February 18, 1999 (File No. 1-12534))
4.2	Indenture dated as of October 15, 1997 among Newfield, as issuer, and Wachovia Bank, National Association (formerly First Union National Bank), as trustee (incorporated by reference to Exhibit 4.3 to Newfield s Registration Statement on Form S-4 (Registration No. 333-39563))
4.3	Senior Indenture dated as of February 28, 2001 between Newfield and Wachovia Bank, National Association (formerly First Union National Bank), as Trustee (incorporated by reference to Exhibit 4.1 to Newfield s Current Report on Form 8-K filed with the SEC on February 28, 2001 (File No. 1-12534))
4.4.1	Subordinated Indenture dated as of December 10, 2001 between Newfield and Wachovia Bank, National Association (formerly First Union National Bank), as Trustee (incorporated by reference to Exhibit 4.5 of Newfield s Registration Statement on Form S-3 (Registration No. 333-71348)
4.4.2	First Supplemental Indenture to Subordinated Indenture dated as of August 13, 2002 between Newfield and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 of Newfield s Current Report on Form 8-K filed with the SEC on August 13, 2002 (File No. 1-12534))
10.1	Newfield Exploration Company 1989 Stock Option Plan (incorporated by reference to Exhibit 10.1 to Newfield s Registration Statement on Form S-1 (Registration No. 33-69540))
10.2	Newfield Exploration Company 1990 Stock Option Plan (incorporated by reference to Exhibit 10.2 to Newfield s Registration Statement on Form S-1 (Registration No. 33-69540))
10.3	Newfield Exploration Company 1991 Stock Option Plan (incorporated by reference to Exhibit 10.3 to Newfield s Registration Statement on Form S-1 (Registration No. 33-69540))
10.4	Newfield Exploration Company 1993 Stock Option Plan (incorporated by reference to Exhibit 10.4 to Newfield s Registration Statement on Form S-1 (Registration No. 33-69540))
10.5.1	Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 4.1 to Newfield s Registration Statement on Form S-8 (Registration No. 33-92182))

Exhibit Number	Title
10.5.2	First Amendment to Newfield Exploration Company 1995 Omnibus Stock Plan (incorporated by reference to Exhibit 10.1 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))
10.6.1	Newfield Exploration Company 1998 Omnibus Stock Plan (incorporated by reference to Exhibit 4.1.1 to Newfield s Registration Statement on Form S-8 (Registration No. 333-59383))
10.6.2	Amendment of 1998 Omnibus Stock Plan, dated May 7, 1998 (incorporated by reference to Exhibit 4.1.2 to Newfield s Registration Statement on Form S-8 (Registration No. 333-59383))
10.6.3	Second Amendment to Newfield Exploration Company 1998 Omnibus Stock Plan (as amended on May 7, 1998) (incorporated by reference to Exhibit 10.2 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 (File No. 1-12534))
10.7.1	Newfield Exploration Company 2000 Omnibus Stock Plan (as amended and restated effective February 14, 2002) (incorporated by reference to Exhibit 10.7.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2001 (File No. 1-12534))
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10.8	Newfield Exploration Company 2000 Non-Employee Director Restricted Stock Plan (incorporated by reference to Exhibit 10.18 to Newfield s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 1-12534))
10.9.1	Newfield Employee 1993 Incentive Compensation Plan (incorporated by reference to Exhibit 10.5 to Newfield s Registration Statement on Form S-1 (Registration No. 33-69540))
10.9.2	Amendment to Newfield Employee 1993 Incentive Compensation Plan (effective as of February 14, 2002) (incorporated by reference to Exhibit 10.9.2 to Newfield s Annual Report on Form 10-K for the year ended December 31, 2001 (File No. 1-12534))
10.10	Newfield Exploration Company Deferred Compensation Plan (incorporated by reference to Exhibit 10.11 to Newfield s Registration Statement on Form S-3 (Registration No. 333-32587))
10.11	Employment Agreement between Newfield and Joe B. Foster dated January 31, 2000 (incorporated by reference to Exhibit 10 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2000 (File No. 1-12534))
10.12	Resolution of Members Establishing the Preferences, Limitations and Relative Rights of Series A Preferred Shares of Huffco China, LDC dated May 14, 1997 (incorporated by reference to Exhibit 10.15 to Newfield s Registration Statement on Form S-3 (Registration No. 333-32587))
10.13	Newfield Exploration Company 2003 Incentive Compensation Plan
10.14.1	Credit Agreement, dated as of January 23, 2001, among Newfield, The Chase Manhattan Bank, as Agent, and the banks signatory thereto (the Credit Agreement) (incorporated by reference to Exhibit 10.2.1 to Newfield s Current Report on Form 8-K filed with the SEC on February 7, 2001 (File No. 1-12534))
10.14.2	First Amendment Agreement, dated as of January 31, 2001, amending the Credit Agreement (incorporated by reference to Exhibit 10.2.2 to Newfield s Current Report on Form 8-K filed with the SEC on February 7, 2001 (File No. 1-12534))
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10.14.5	Fourth Amendment Agreement, dated as of November 1, 2002, amending the Credit Agreement (incorporated by reference to Exhibit 10.1 to Newfield s Current Report on Form 8-K filed with the SEC on December 5, 2002 (File No. 1-12534))
10.14.6	Fifth Amendment, dated as of March 24, 2003, amending the Credit Agreement (incorporated by reference to Exhibit 10.1 to Newfield s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2003 (File No. 1-12534))

Exhibit Number	Title
10.15	Registration Rights Agreement, dated as of May 29, 2002, by and among Newfield, Warburg, Pincus Equity Partners, L.P., Warburg, Pincus Netherlands Equity Partners I, C.V., Warburg, Pincus Netherlands Equity Partners II, C.V. and Warburg, Pincus Netherlands Equity Partners III, C.V. (incorporated by reference to Exhibit 10.3 to Newfield s Current Report on Form 8-K filed with the SEC on May 30, 2002 (File No. 1-12534))
*21.1	List of Significant Subsidiaries
**23.1	Consent of PricewaterhouseCoopers LLP
*31.1	Certification of Chief Executive Officer of Newfield Exploration Company pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31.2	Certification of Chief Financial Officer of Newfield Exploration Company pursuant to 15 U.S.C. Section 7241, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*32.1	Certification of Chief Executive Officer of Newfield Exploration Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*32.2	Certification of Chief Financial Officer of Newfield Exploration Company pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* Filed or furnished with our Annual Report on Form 10-K for the year ended December 31, 2003 as originally filed on March 15, 2004.

** Filed or furnished herewith.

Identifies management contracts and compensatory plans or arrangements.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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, on the 9th day of August, 2004.

NEWFIELD EXPLORATION COMPANY

By: /s/ TERRY W. RATHERT

Terry W. Rathert
Vice President and Chief Financial Officer

INDEX TO EXHIBITS

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