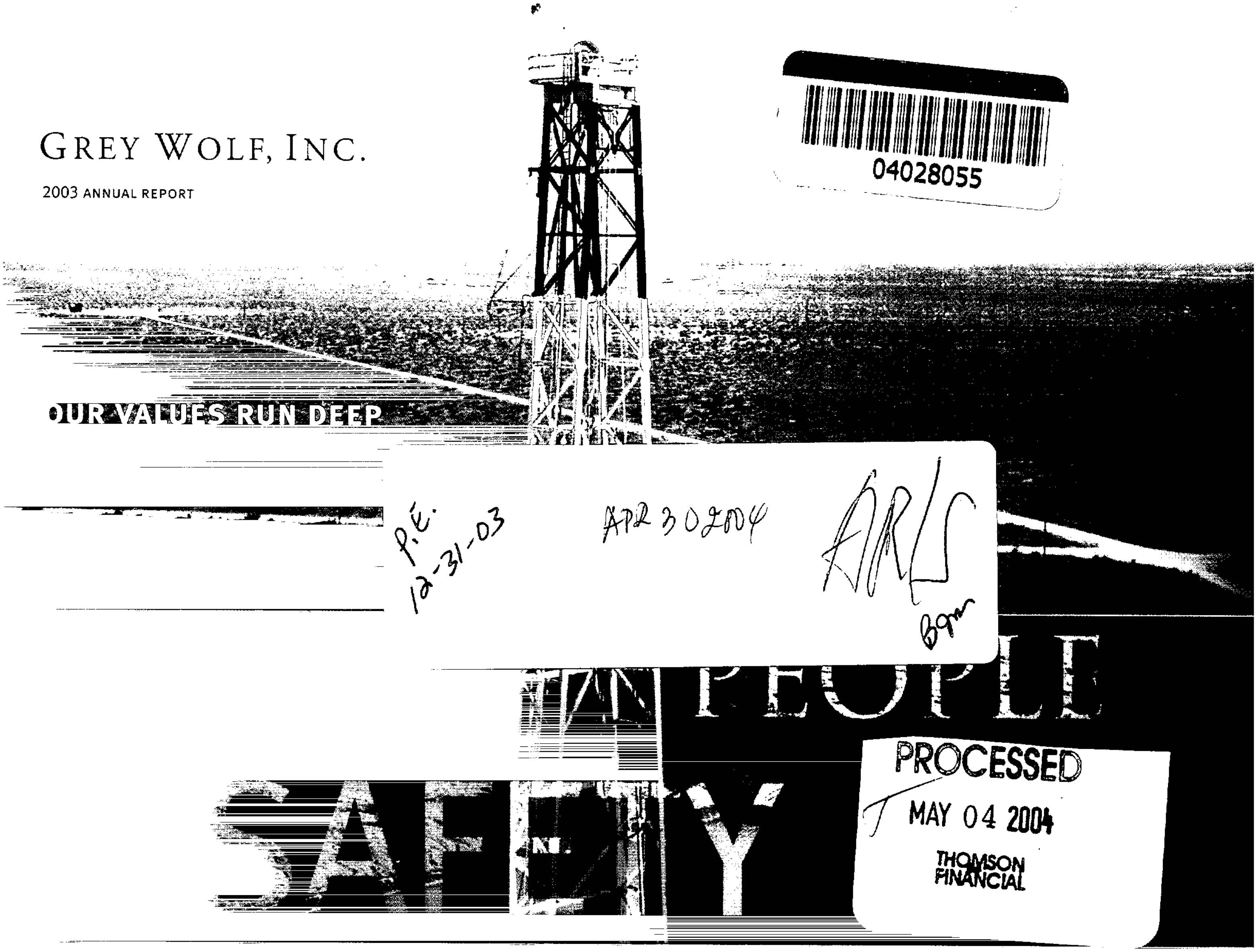
GREY WOLF, INC.

2003 ANNUAL REPORT



OUR VALUES RUN DEEP

PEOPLE

SAFETY

PERFORMANCE

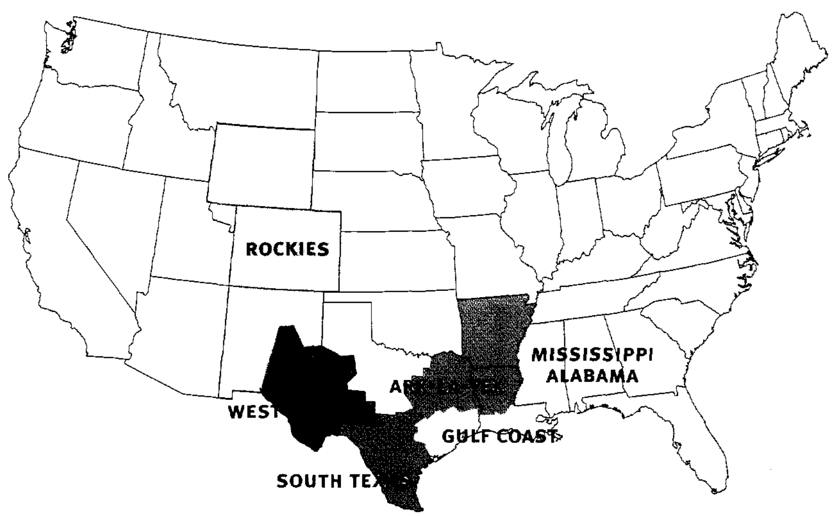
EXCELLENCE

SHAREHOLDER FOCUSED

OUR VALUES RUN DEEP

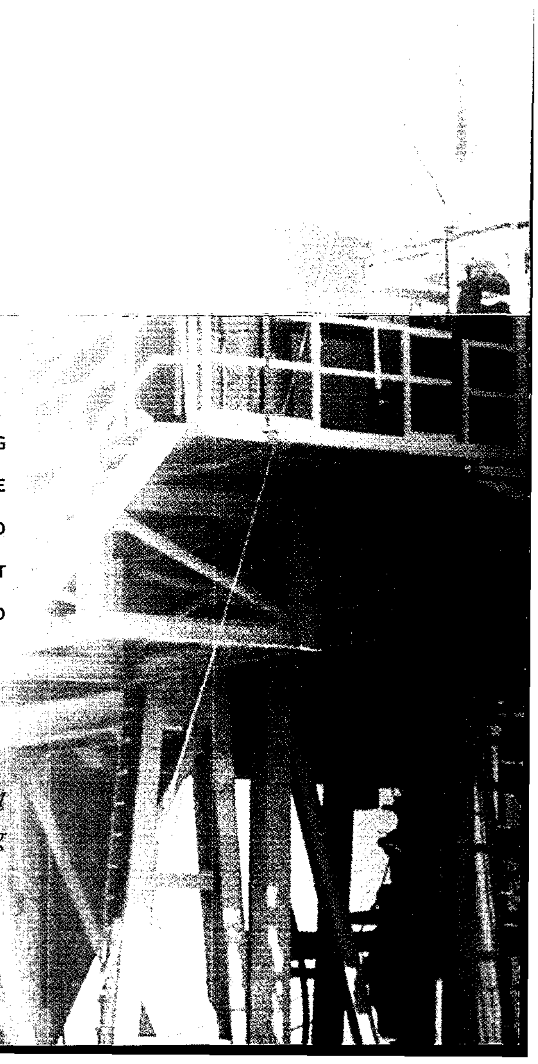
As a leading provider of contract land drilling services, Grey Wolf serves major and independent oil and gas firms with a fleet of 117 drilling rigs. The Company's markets are the South Texas, Gulf Coast, Ark-La-Tex, Mississippi/Alabama, West Texas and Rocky Mountain regions – areas with significant natural gas reserves.

Grey Wolf today represents a combination of drilling firms whose histories dated to the early 1900s. Preserving the best of those successful corporate cultures, our values run deep and define the Company's focus.



MISSION STATEMENT

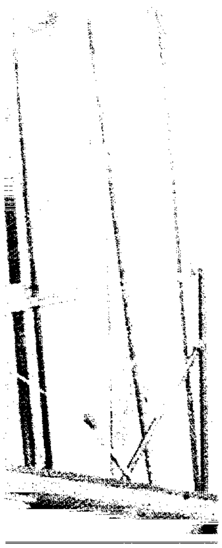
Grey Wolf's mission is to achieve optimum results for our shareholders by providing our customers with the best operational value and service while upholding the other deeply ingrained core values critical to long-term success: hiring and developing the best-qualified people, utilizing a well-maintained equipment fleet and new technologies, emphasizing high expectations for performance and integrity, and upholding the highest safety standards.



ON THE COVER:
Rig 88, shown here on location for Tom Brown, Inc. in West Texas, was the first U.S. land rig to utilize 2,200-horsepower mud pumps that enhance drilling efficiency by providing greater hydraulic power at the drill bit.

FINANCIAL HIGHLIGHTS

(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)



	2003	2002	2001	2000	1999	1998
Revenues	$ 285,974	$ 250,260	$ 433,739	$ 276,758	$ 148,465	$ 244,120
Net income (loss) applicable to common shares	(30,200)	(21,476)	68,453	(8,523)	(41,262)	(83,213)
Earnings (loss) per share: Basic and diluted	(.17)	(.12)	.38	(.05)	(.25)	(.50)
Total assets	529,078	590,623	625,471	512,370	453,852	501,303
Long-term debt	234,898	249,613	250,695	249,851	249,962	250,832
Shareholders' equity	195,637	225,258	245,297	173,416	125,577	166,691
Working capital	68,727	114,353	113,163	60,029	16,353	44,489

OPERATIONAL HIGHLIGHTS

	2003	2002	2001	2000	1999	1998
Operating days	22,147	20,080	30,924	26,107	16,436	26,230
Average revenue per rig day	$ 12,913	$ 12,463	$ 14,026	$ 10,601	$ 9,033	$ 9,307
Average margin per rig day	$ 1,882	$ 2,674	$ 5,963	$ 2,150	$ 382	$ 1,824
Average rigs operating	61	55	85	71	45	72

TO OUR SHAREHOLDERS

WHILE THE YEAR 2003 BROUGHT A SLOWER RECOVERY IN NATURAL GAS DRILLING THAN MOST INDUSTRY EXPERTS HAD PREDICTED, GREY WOLF HAD A RECORD YEAR IN TURNKEY WORK AND SIGNIFICANTLY STRENGTHENED ITS BALANCE SHEET THROUGH A MAJOR DEBT REFINANCING.

The Company reported a net loss of $30.2 million, or $0.17 per share on a diluted basis, for the year compared to a net loss of $21.5 million, or $0.12 per share on a diluted basis, for 2002. Included in the loss for 2003 are expenses of $8.5 million ($5.6 million after tax) related to refinancing 60% of our long-term debt – a transaction that will strengthen the Company's balance sheet by reducing our interest expense approximately $9.5 million per year and extending the debt maturity from 2007 to 2023, subject to call in 2013.

Revenues for 2003 climbed to $286.0 million from $250.3 million a year ago on the strength of our turnkey business. Turnkey generated approximately 50% of our $41.7 million in operating margin on just under 16% of the total days worked. Grey Wolf's turnkey team took advantage of market conditions and performed above expectations to achieve a record year.

Utilization climbed industrywide in 2003, and we averaged a total of 61 rigs working, up from 55 rigs in 2002. Rates did not increase significantly, however, so our daywork results were influenced by the expiration of long-term drilling contracts signed at higher dayrates than available today as well as the lagging recovery in deep-drilling activity. Our premium rig fleet has a deep-drilling bias, so in 2003 many rigs operated at a margin disadvantage on shallower, less technically complex wells.

Grey Wolf remained committed to enhancing margins and exercising discipline in our capital spending programs in 2003. We eliminated expenses that did not add essential value for our customers and reduced overhead costs, while the cost of being a public company and the cost of regulatory compliance increased significantly.

ASSET ACQUISITIONS

In June 2003, Grey Wolf purchased two land drilling rigs for $9.0 million from El Paso Corporation. In conjunction with the rig purchase, we signed a term contract to provide 1,460 days of drilling services for subsidiaries of El Paso. Capital expenditures for 2003 totaled $35.1 million including the rigs purchased from El Paso. We also increased the number of top drives in our fleet by one to a total of 15 and upgraded and winterized two additional rigs to work in the Rocky Mountain market.

DIRECTORS
(STANDING) ROBERT E. ROSE, FRANK M. BROWN, JAMES K.B. NELSON, WILLIAM T. DONOVAN

(SEATED) WILLIAM R. ZIEGLER, THOMAS P. RICHARDS, STEVEN A. WEBSTER

OFFICERS
(STANDING) DONALD J. GUEDRY, JR., MERRIE S. COSTLEY, EDWARD S. JACOB III, DAVID W. WEHLMANN

(SEATED) GARY D. LEE, WILLIAM E. CHILES

MERGER ENHANCES GEOGRAPHIC EXPANSION

To further strengthen our position in the Rocky Mountain market, we have just announced the signing of a merger agreement to acquire New Patriot Drilling Corp. for $16.3 million in cash and 4,610,480 shares of Grey Wolf common stock. In addition, Grey Wolf will retire the outstanding debt of Patriot that is expected to be $13.7 million at closing. With closing scheduled for April 2004, we will expand our fleet operating in the Rocky Mountains from four to 14 rigs, including three diesel-electric and seven mechanical rigs owned by Patriot. Patriot's team, bringing extensive experience in this market area and strong customer relationships, will join Grey Wolf and direct the operations of the Rocky Mountain division. The purchase will bring our rig fleet to 127 rigs, including 92 marketed rigs and 20 cold stacked rigs that can be deployed quickly as market conditions warrant.

Grey Wolf continues to increase its presence in markets with the most prolific natural gas resources, including West Texas, where we were able to maintain 90% utilization in 2003 and recently activated our seventh rig.

POSITIVE MARKET OUTLOOK

Commodity prices, the primary driver for land drilling, remain at very attractive levels. Our customers are building cash and continue to improve their balance sheets. This encourages both exploratory and developmental drilling. As the current cycle lengthens, we expect drilling programs to move to the deeper, more difficult geological plays that provide the best opportunities for our premium rig fleet.

We expect our results in 2004 to reflect the industry's improved fundamentals.

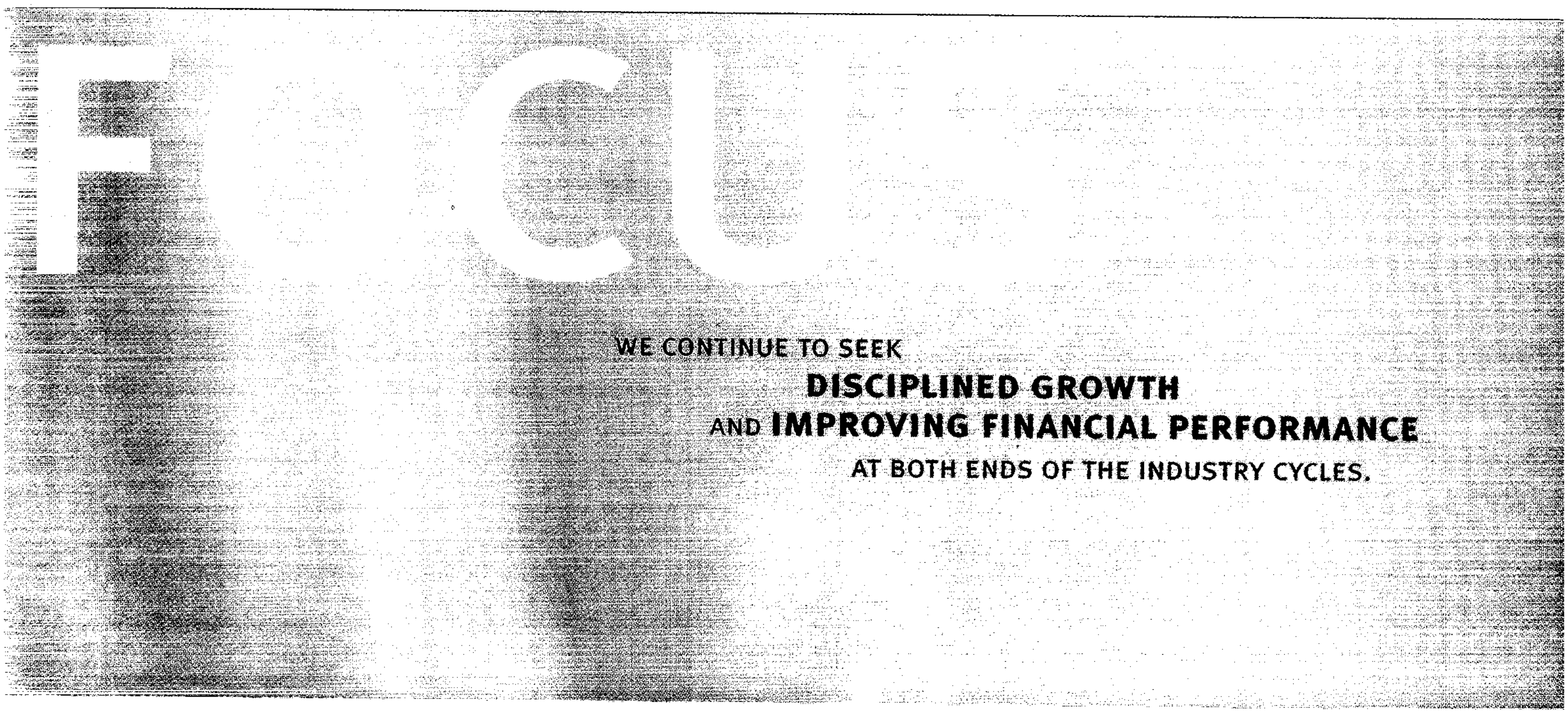
OUR VALUES RUN DEEP

At a time when sound corporate governance is an issue being examined nationwide, we continue to strengthen our management team and develop leaders among our employee ranks. Grey Wolf's core values, highlighted in this report, are deeply ingrained. Two are of special significance: maintaining integrity in all our endeavors and focusing on the interests of our shareholders.

Whether it's refinancing debt to enhance the balance sheet, reducing non-essential costs to boost margins, entering new market areas to build revenues, or making innovations to boost productivity, we continue to seek disciplined growth and improving financial performance at both ends of the industry cycles. I appreciate the support of our shareholders and the dedication of our employees in this effort.

Sincerely,

THOMAS P. RICHARDS
Chairman, President and Chief Executive Officer
March 8, 2004



CUSTOMERS VALUE OUR COMMITMENT TO **PERFORMANCE EXCELLENCE**

UNCERTAIN GEOLOGY AND HARSH ENVIRONMENTS CHALLENGE THE MOST EXPERIENCED RIG CREWS, SO DRILLING TO A TARGETED DEPTH ON A PROJECTED SCHEDULE IS A TOUGH TASK. UNSCHEDULED EVENTS CAN DELAY DRILLING AND BOOST COSTS.

That's why customers value Grey Wolf's commitment to performance excellence. That commitment made all the difference to Bill Dannels, a division drilling superintendent for Bass Enterprises Production Company: *"Because of Grey Wolf's reputation and performance on the Gulf Coast, Rig 33 was contracted to drill a 12,300-foot well near Carlsbad, New Mexico. Our results were outstanding – the well was drilled and rig released 14 days ahead of the drilling curve. Our well drilled eight days faster than the previous fastest well in the area. New and improved bits and downhole motors, along with the rig personnel to run this higher technology equipment, made the difference."*

The teamwork of highly trained, experienced and motivated employees coupled with a fleet of well-maintained rigs with the latest technologies reflects Grey Wolf's pursuit of performance excellence.

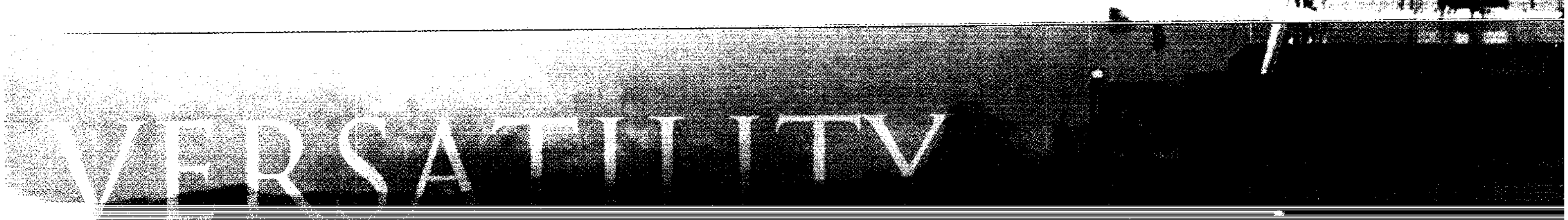
VERSATILE DRILLING FLEET

Grey Wolf maintains a versatile drilling fleet of 117 rigs with ratings of 600- to 4,000-horsepower. A list of our rigs is available at www.gwdrilling.com.

More than 95% of the fleet, including 61 diesel-electric and 18 trailer-mounted rigs, is rated to drill to depths greater than 10,000 feet. Our equipment also adapts efficiently to the challenges of shallow, but complex horizontal and multi-directional wells. To drill these wells, which accounted for more than a third of U.S. land drilling in 2003, customers are taking advantage of advances in drilling and completion technology.

All of Grey Wolf's rigs are equipped with electronic digital drilling systems providing efficient data management, real-time analysis and greater drilling control. Improvements in solids control and fluids handling capabilities in recent years include larger mud pumps to enhance power at the drill bit and move solids quickly.

Grey Wolf invested $17.6 million in 2003 on equipment upgrades, refurbishments and acquisitions, including $9.0 million for the purchase of two SCR rigs from El Paso Corporation and $800,000 for an additional top drive.



With capacities of 250- to 750-tons, Grey Wolf's 15 top drives – acquired over the past four years – enable a rig to drill in 90 foot increments – triple the length possible without a top drive. Productivity improves dramatically, justifying the additional dayrate for this equipment, now a mainstay of advanced drilling technology that is suited for use on most of the Company's rigs.

Grey Wolf offers customers rapid mobilization capabilities with its fleet of trailer-mounted rigs that can be moved to new drilling locations in half the time of conventional rigs. A fleet of trucks and cranes supported by shop facilities located in Texas and Louisiana also assures faster rigups and rigdowns on site.

Efficiency in drilling or rig moves does not happen without personnel dedicated to performance excellence whose talents include the right balance of engineering expertise and operational experience. Grey Wolf's engineering team creates innovative drilling solutions, improving productivity and creating significant cost savings for customers. Experienced crews execute the programs safely and efficiently. The success in our turnkey business wouldn't be possible without the competitive advantage attained through this marriage of engineering discipline and operations know-how.

Turnkey Tests Equipment and Personnel

Grey Wolf is the leading land drilling contractor providing turnkey services to oil and gas companies in its traditional markets. The Company provides all the services associated with drilling to a specified depth and bears the drilling related risks and costs.

Since 1997, Grey Wolf has drilled 728 turnkey wells in our traditional market areas. Turnkey work represented just under 16% of activity in 2003, contributing $21.0 million to total operating margin, a record for Grey Wolf. On a per-day basis, turnkey operating margin was $6,094 versus $1,106 for daywork.

"The average contractor does poorly on turnkey and tackles these projects only when times are bad," notes Joey Hopewell, Vice President of Turnkey Services. *"It's very challenging but we've been successful. We have consistently made money in this business, whether the market is up or down."*

Critical factors for success are accurate risk assessment and bidding, solid engineering work, and efficient field operations. *"We're a leader in this business because we do these things well,"* concludes Hopewell.

The successful combination of expertise and equipment has built Grey Wolf's reputation for performance excellence and facilitated expansion into the West Texas and the Rocky Mountain markets over the past two years.

Four drilling rigs, operated out of Casper, Wyoming, are well-suited to the challenging, harsh-weather projects of the Rocky Mountains. Grey Wolf will add another 10 rigs to this market with the anticipated merger with New Patriot Drilling Corp., scheduled to close in April 2004. Meanwhile, seven of our mid-range rigs are tackling projects in West Texas, where Grey Wolf achieved 90% rig utilization in 2003 by providing premium rigs in a market previously dominated by lower-horsepower, mechanical rigs. Both markets offer exciting growth potential and build on our long tradition of operating in those areas with the richest natural gas resources in North America.

A VERSATILE DRILLING FLEET
OFFERS THE MOST EFFICIENT AND PRODUCTIVE
TOOLS FOR EACH PROJECT.

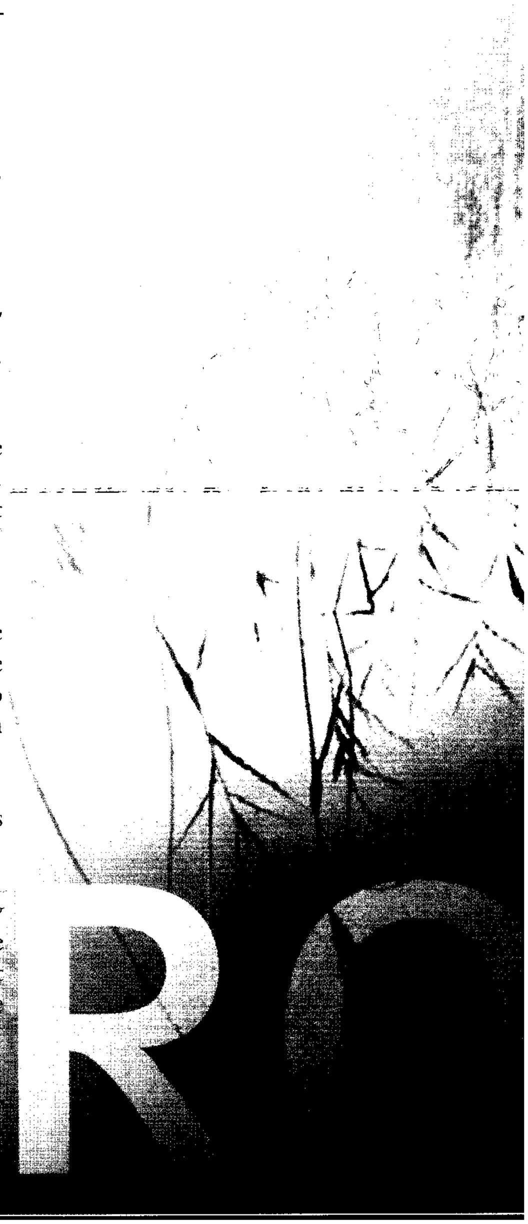
DIGITAL INSTRUMENTATION INCREASES PRODUCTIVITY.

GREY WOLF UPHOLDS A STRONG COMMITMENT TO
SAFETY AND THE ENVIRONMENT

IN THE MARSHES OF THE SABINE WILDLIFE REFUGE IN SOUTHWEST LOUISIANA ON A SLIM STRETCH OF LAND ONLY ACCESSIBLE BY WATER, THE TASK OF BARGING TONS OF DRILLING EQUIPMENT IN, TRUCKING IT ACROSS A BOARD ROAD AND MANEUVERING AROUND THE LANDOWNER'S HERD OF BUFFALO PRESENTED CHALLENGES. BARGING THE DRILLING CUTTINGS AND MUD BACK OUT TO PROTECT THE ENVIRONMENT WAS ALL IN A DAYS WORK ON THIS PROJECT, COMPLETED BY RIG 503 LAST YEAR.

"Our crews distinguish themselves each day by maintaining high standards across the board in safety and operational excellence while protecting the environment," notes Ed Jacob, Senior Vice President of Operations.

Protecting the environment, the health and safety of employees, and the people who are affected by our operations is not just the right thing to do, it's good business. That philosophy begins with Grey Wolf's top managers and is reinforced throughout the organization.



Customers Evaluate Safety Records

Customers recognize the value of a solid safety record. Operators frequently weigh the safety record of a rig in awarding a bid because the impact of an injury is twofold: the cost of unscheduled downtime and the cost of lost productivity when the teamwork so vital to performance excellence is disrupted. The average cost of an injury resulting in even one day of lost time is $28,000, according to the National Safety Council.

The Company invests in a wide range of safety and operations training programs designed to promote constant vigilance to potential hazards and environmental risks.

With the goal of an accident-free workplace, Grey Wolf has reduced its incident rate by two-thirds since 1997 and performed better than the drilling contractors' industry composite for each of the past five years. In 2003, 27 of Grey Wolf's working rigs recorded at least one year without a recordable doctor case. Rig 86, for example, recently surpassed the four-year milestone.

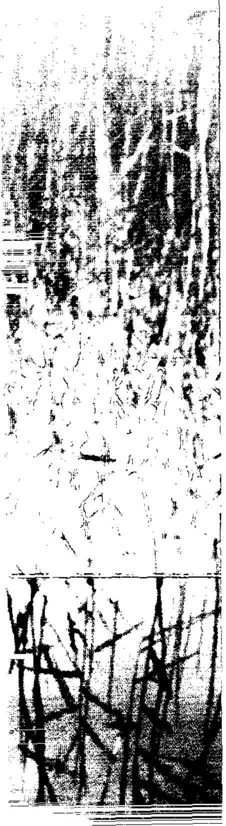
"We have an experienced crew and none of us wants to get hurt," says Pat Kristek, a rig manager who assisted in refurbishing Rig 86 and has worked steadily with its crew since [illegible] Operating out of the South Texas Division, this SCR rig is capable of drilling to 25,0[illegible]

SAFETY

GREY WOLF IS COMMITTED

TO PROTECTING THE ENVIRONMENT, THE HEALTH AND SAFETY OF EMPLOYEES AND PEOPLE AFFECTED BY OUR OPERATIONS.

MORE THAN 1,800 EMPLOYEES AND SPOUSES PARTICIPATED
FAMILY SAFETY MEETINGS IN 2003.



To help crews meet similar safety milestones, Grey Wolf holds daily briefings as well as job safety analysis meetings before each phase of a drilling operation to highlight the safest and most efficient way to perform an upcoming procedure. Safety training regularly includes such topics as well control, fall protection, back safety, chemicals handling, pinch points including hand safety, and hazard identification, particularly in confined spaces.

Behavior-Based Safety Training

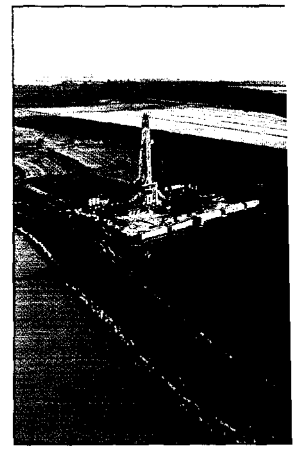
In addition, the Company is investing in a behavior-based, three-day safety leadership training program first implemented in 2003 with the Gulf Coast Division.

Our Safety Observations and Corrections Program encourages every employee at a job site to track unsafe conditions, near misses, and at-risk behaviors as well as a variety of positive safety activities. In turn, employees are rewarded for tracking the behaviors, alerting crew members, and for improvements in the rate of injuries requiring a doctor visit. The training program is proving highly effective in promoting safety consciousness and will be expanded across the divisions in 2004.

Safe Equipment Design

Designing and maintaining equipment with safety in mind lays the foundation for a safe environment. In the last industry upturn, Grey Wolf undertook a refurbishment program as it deployed increasing numbers of rigs under contract. One aim was to incorporate the latest technological advances. The other was standardizing equipment and procedures from rig-to-rig to create maintenance and training economies that would result in safer and more efficient working conditions.

To customers, the outstanding condition and cleanliness of Grey Wolf's equipment – standard across the fleet – is a unique selling point, a tangible demonstration of its commitment to safety and the environment.



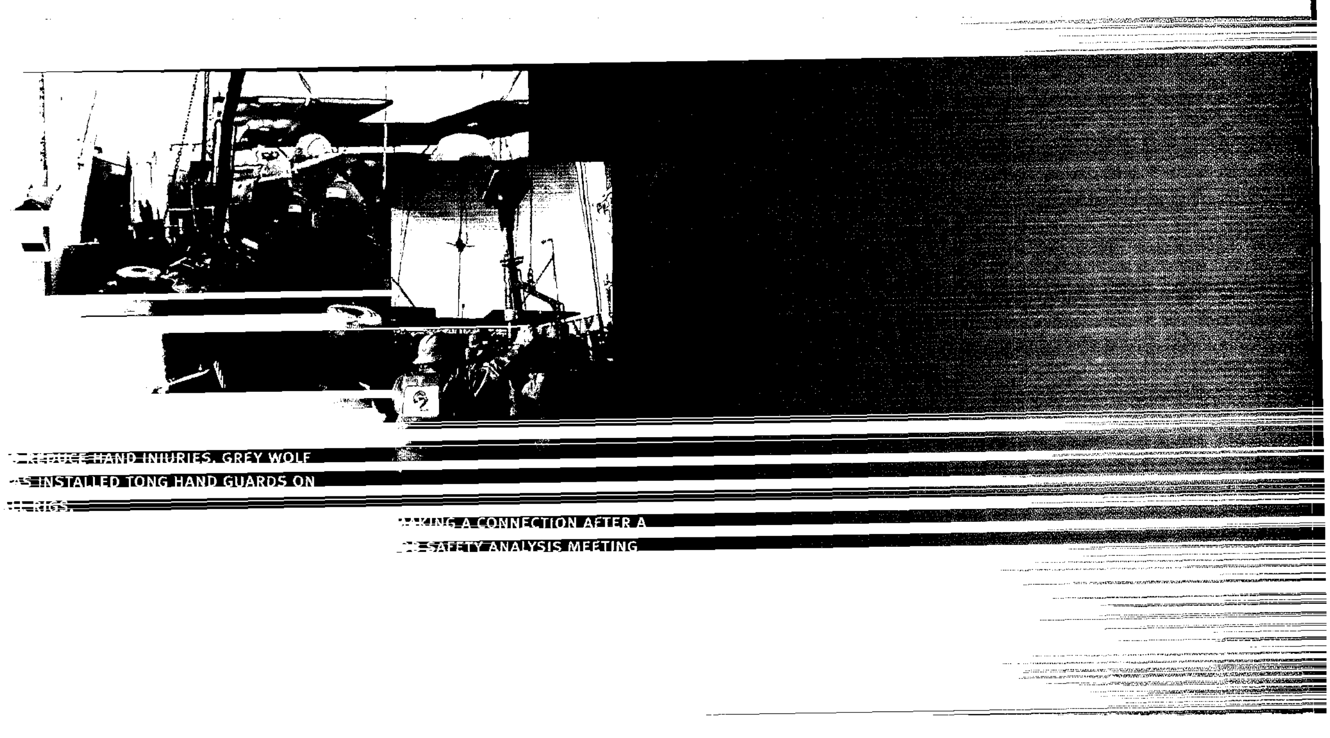
RIG 45
VERMILION PARISH, LOUISIANA

Attention to Detail

"If we are not tripping pipe, we are scrubbing something all the time," notes Johnny Day, a rig manager on Grey Wolf's 1,000-horsepower SCR Rig 17. *"It is a simple safety rule. Keeping the rig clean provides a safe working environment."*

Rig cleanliness also reflects the company's ongoing commitment to leaving each rig location better than it was found. A host of EPA and OSHA regulations are carefully observed, but the Company sets its own high environmental standards as well.

Striving for the highest levels of safety performance and stewardship of the environment are among the core values that define Grey Wolf. These values run deep and define the Company's focus on performance excellence, shareholder value and integrity.



...REDUCE HAND INJURIES, GREY WOLF ...AS INSTALLED TONG HAND GUARDS ON ... RIGS.

...KING A CONNECTION AFTER A ... SAFETY ANALYSIS MEETING

GIVING OUR EMPLOYEES THE OPPORTUNITY **TO GROW AND LEAD**

INVESTING IN THE PEOPLE OF GREY WOLF IS AS CRITICAL TO LONG-TERM SUCCESS AS INVESTING IN THE EQUIPMENT IN OUR PREMIUM DRILLING FLEET.

"Our employees are a top priority and our objective is to bring them the best tools, whether that means drilling equipment or training classes, so they can perform at the highest levels of safety, efficiency and cost effectiveness," notes Grey Wolf Chairman, President and Chief Executive Officer Tom Richards, who in 35 years has risen through the ranks of the drilling industry beginning first as a roughneck, then later as driller and as rig manager on rigs.

Grey Wolf promotes from within and invested $2.8 million in 2003 in safety and training programs that give employees in all areas – from rig operations to finance and administration – the opportunity to grow and lead.

Through its long-time policy of retaining key people in industry downturns, Grey Wolf has created a significant strategic advantage by providing customers with quality crews whose continuous training, outstanding safety records, and cohesive work history add value at the well site. In a cyclical industry that faces ongoing challenges in the recruitment of new talent, Grey Wolf depends on its leadership development programs as well as its "family ties" to strengthen supervisory ranks. In each of the Divisions, careers are built by family members – fathers and sons, brothers and cousins – who recognize the unique opportunities provided by Grey Wolf's commitment to skilled people.

The career of David Weber, Sr., a retiree who came up from the drilling rig floor to superintendent during his 32 years with the Company, is mirrored by that of his son, David Weber, Jr., a 30-year employee. Both joined Flournoy Drilling Company, a predecessor of today's Grey Wolf.

"Like my dad, I started as a roughneck and worked my way up to drilling superintendent in the South Texas Division. When he retired, I moved right into his office. All they had to do was change a letter on the nameplate." Weber attributes his long tenure at Grey Wolf to working with people he trusts. *"If there is honesty, integrity, and you can trust the word of the men you are working with, you will come to work every day with no problems,"* he explains.

Indeed, it is integrity that lays the foundation for Grey Wolf's commitment to people, to performance excellence, to safety and the environment and, ultimately, to its shareholders. Our core values run deep and provide the strategic advantages that forge success.

GENERATIONS OF DEDICATION
DAVID WEBER, SR. AND DAVID WEBER, JR.

WITH MORE THAN 60 YEARS COMBINED SERVICE, THIS FATHER-SON TEAM REFLECTS THE COMPANY'S COMMITMENT TO LEADERSHIP DEVELOPMENT.

ENGINEERING INNOVATOR - ROBERT URBANOWSKI

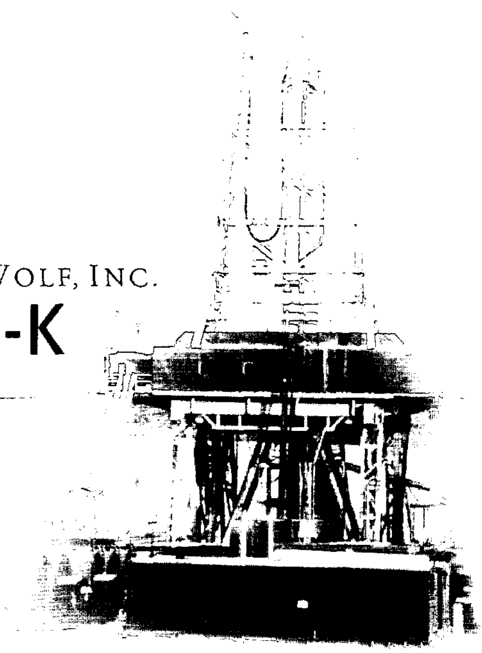
From summer yard hand to manager of engineering, Robert Urbanowski's career with Grey Wolf has fueled his penchant for innovation.

"My second summer I was a roustabout on Rig 505. When I graduated from Texas A&M, I joined the company full-time roughnecking and drilling," he recalls. He began working turnkey assignments as an engineer in 1989 and was appointed Manager of Engineering in 2000, focusing on equipment standardization and technology. He designed Rig 88's new 2,200 horsepower mud pump system – the first use on a U.S. land rig – and engineered the company's two- and three-mud tank systems that enhance solids control.

With a host of impressive industry affiliations that include committees of the International Association of Drilling Contractors and the Society of Petroleum Engineers, Urbanowski stays on the leading edge. He recommended using a new high-tensile, 5 7/8" drill string – its first use in land drilling – to reduce the time it would take Rig 558 to complete a 25,000-foot well in Wyoming. While he credits the on-site crews and customer, he was right. The well was drilled in 256 days, beating the record of 330 days for that depth.

GREY WOLF, INC.

FORM 10-K



UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

[X] Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the Fiscal Year Ended December 31, 2003

[ ] Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Commission file number 1-8226

GREY WOLF, INC.
(Exact name of registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	**74-2144774** (I.R.S. Employer Identification Number)
10370 Richmond Avenue, Suite 600 **Houston, Texas** (Address of principal executive offices)	**77042** (Zip Code)

Registrant's telephone number, including area code: **713-435-6100**

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 $0.10	**American Stock Exchange**
Rights to Purchase Junior Participating Preferred Stock, Par Value $1.00	**American 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 [✓] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (229.405 under the Securities Exchange Act of 1934) is not contained herein, and will not be contained, to the best of 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. [✓]

At February 10, 2004, 181,437,431 shares of the Registrant's common stock were outstanding. The aggregate market value of the Registrant's voting stock held by non-affiliates (based upon the closing price on the American Stock Exchange on February 10, 2004 of $4.25) was approximately $718.6 million.

Indicate by a check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act) Yes [✓] No [ ].

The following documents have been incorporated by reference into the Parts of this Report indicated: Certain sections of the Registrant's definitive proxy statement for the Registrant's 2004 Annual Meeting of shareholders which is to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 within 120 days of the Registrant's fiscal year ended December 31, 2003, are incorporated by reference into Part III hereof.

PART I

ITEM 1. BUSINESS

General

Grey Wolf, Inc., a Texas corporation formed in 1980, is a leading provider of contract land drilling services in the United States. Our customers include independent producers and major oil and gas companies. We conduct all of our operations through our subsidiaries. Our principal office is located at 10370 Richmond Avenue, Suite 600, Houston, Texas 77042, and our telephone number is (713) 435-6100. Our website address is www.gwdrilling.com.

We make available free of charge through our website our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with the Securities and Exchange Commission. Information on our website is not a part of this report. Unless the context otherwise requires, reference in this Report on Form 10-K to "we", "us", "our" or "Grey Wolf" refer to Grey Wolf, Inc. and its subsidiaries.

Business Strategy

Within the framework of a very cyclical industry, our strategy is to maximize shareholder value during each phase of an industry cycle. To achieve that strategy, we seek to enter each phase of our industry's cycles in a stronger position by:

- delivering quality, value-added service to our customers;
- maintaining a leading position in certain markets where we operate;
- responding to market conditions by balancing dayrates we receive on our rigs with the number of rigs we market;
- maintaining a high level of utilization for our marketed rigs;
- enhancing cash flow through our turnkey and trucking operations and use of our top drives;
- controlling costs and exercising capital spending discipline;
- maintaining a premium fleet of equipment with a bias toward deep drilling for natural gas;
- using term contracts to provide sufficient cash flow to cover incremental capital expenditures for refurbishments on rigs under term contracts;
- using term contracts to mitigate the cyclical nature of dayrates;
- searching for new market opportunities where we believe our quality fleet of rigs would be able to generate attractive returns; and
- searching for potential acquisition candidates that we believe would be accretive.

Industry Overview

At the peak of the last up cycle in July 2001, there were 1,136 land rigs working in the United States according to the Baker Hughes rotary rig count. That number fell to 628 in April of 2002, we believe due to lower commodity prices. From April 2002 through December 2002, commodity prices generally improved and we saw a stabilization of the domestic land rig count at an average of 710 rigs. From the end of 2002 through the end of January 2004, the average closing price for natural gas, based upon the NYMEX near month contract was $5.52 per mmbtu, while the average NYMEX near month contract price of West Texas Intermediate Crude was $31.16 per barrel. During this time period, the closing prices did not fall below $4.43 per mmbtu and $25.24 per barrel for natural gas and West Texas Intermediate Crude, respectively. Over this same period of time, the number of land rigs working domestically increased to 988.

Current Conditions and Outlook

The last up cycle in our industry, which began in the second half of 1999 and continued through the third quarter of 2001, was marked by rapidly increasing dayrates, significant backlog and reactivation of rigs from cold-stacked status and inventory. Dayrates began increasing when the U.S. land rig count reached approximately 600 rigs on the Baker Hughes rotary rig count and continued to rise until roughly mid-2001. Backlog, in the form of signed contracts and non-binding oral commitments from customers, generally extended beyond six months and through the use of term contracts extended up to two years.

Although the domestic land rig count has increased from 628 in April 2002 to 988 at the end of January 2004, we believe that the current cycle of increasing rig count differs from the last in that, to date, dayrates have increased only slightly and we believe backlog has yet to build to levels seen in 2001. We believe there are a number of factors that contribute to the overall lack of intensity in the current up cycle.

First, the expansion of the land rig fleet in the last up cycle means there are more rigs available to meet the demand in this cycle with little or no additional capital expenditure. It is estimated that rigs refurbished and reactivated in the last up cycle added between 120 and 150 rigs to the market that are capable of working in this cycle. In addition, new-build rig programs have added between 50 and 60 additional rigs to the market over the last two years.

Second, the customer base that accounts for the largest portion of working land rigs consists of independent producers of oil and gas. We believe that this customer group has, in general, changed its management focus from rapid oil and gas reserve expansion through drilling and acquisition to overall financial health measured by balance sheet strength and adequate returns on capital employed. Under the old focus, we believe that during periods when commodity prices were high, these customers generally applied the greatest portion of available cash to increase reserves. Today, we believe that drilling prospects compete with debt reduction, producing property acquisitions, and stock buybacks for available cash.

Third, we believe the nature of the competitive environment is different. Competition in this up cycle has focused on market share rather than obtaining higher dayrates, which received much stronger emphasis in the last up cycle.

Finally, a general lack of deep drilling has become evident in this up cycle, leaving high horsepower premium rigs idle or under utilized. The number of wells drilled by the top 15 operators to depths greater than 10,000 feet has declined approximately 30% from the peak in 2001 to the present. Also, today there are approximately 50 fewer rigs drilling wells to target depths of 15,000 feet or deeper than were drilling at the peak of the last up cycle. This failure of the deep drilling segment of the market to rebound as quickly as in the past is reflected not only in the number of rigs working but also in lower average operating margins. Rigs drilling deeper wells typically command higher margins.

We believe we are in a solid position to benefit from an increase in drilling activity which we believe could develop in 2004. We continue to maintain our premium fleet of equipment and retain our experienced personnel which are essential to providing quality service to our customers and returning our rigs to work when market conditions improve.

During each quarter in 2003, we averaged between 59 and 62 rigs working and have averaged 63 rigs working thus far in the first quarter of 2004. We have, however, seen an increase in the amount of future work for our rigs currently operating as well as an increase in the dayrates we are currently bidding for our rigs. This future work is in the form of signed contracts and non-binding oral commitments from our customers.

Operations

At February 10, 2004, we had a rig fleet of 117 rigs, 80 of which were marketed, 22 cold-stacked and 15 held for future refurbishment. Cold-stacked rigs are rigs that are stacked without crews, are not currently being marketed and do not require substantial investment to be returned to service. We estimate that our cold-stacked rigs could be returned to service for an aggregate of approximately \$2.5 million to \$3.0 million. We currently conduct our operations in the following domestic drilling markets:

- Ark-La-Tex;
- Gulf Coast;
- Mississippi/Alabama;
- South Texas;
- Rocky Mountain; and
- West Texas.

We conduct our operations primarily in domestic markets which we believe have historically had greater utilization rates and dayrates than the combined total of all other domestic markets. This is in part due to the heavy concentration of natural gas reserves in these markets. During 2003, approximately 98% of the wells we drilled for our customers were drilled in search of natural gas. Larger natural gas reserves are typically found in deeper geological formations and generally require premium equipment and quality crews to drill the wells.

Ark-La-Tex Division. Our Ark-La-Tex division provides drilling services primarily in Northeast Texas, Northern Louisiana and Southern Arkansas, and the Mississippi/Alabama market. We currently have 19 marketed rigs in this division which consist of 11 diesel electric rigs and eight mechanical rigs. Our Ark-La-Tex division also operates a fleet of trucks which is used exclusively to move our rigs. The Ark-La-Tex division also manages the operations of our Rocky Mountain and West Texas districts.

We had an average of 14 rigs working in our Ark-La-Tex division during 2003. Daywork contracts generated approximately 84% of our revenues and 72% of the operating margin in this division during 2003, while turnkey and footage contracts generated the remaining 16% of our revenues and 28% of our operating margin. Operating margin is defined as revenues less drilling operations expenses. The average revenue per rig day worked by the division during 2003 was $10,438.

Gulf Coast Division. Our Gulf Coast division provides drilling services in Southern Louisiana and along the upper Texas Gulf Coast. We currently have 21 marketed rigs in this division which consist of 18 diesel electric rigs and three mechanical rigs.

We had an average of 18 rigs working in our Gulf Coast division during 2003. Daywork contracts generated approximately 40% of our revenues and 34% of our operating margin in this division during 2003, while turnkey and footage contracts generated the remaining 60% of our revenues and 66% of our operating margin. The average revenue per rig day worked by the division during 2003 was $16,002.

South Texas Division. We currently have 30 marketed rigs in this division. The marketed rigs consist of 15 diesel electric rigs, ten trailer-mounted rigs, one of which is diesel electric, and five mechanical rigs. The South Texas division also operates a fleet of trucks which is used exclusively to move our rigs.

We had an average of 22 rigs working in our South Texas division during 2003. Daywork contracts generated approximately 63% of our revenues and 38% of our operating margin in this division during 2003, while turnkey and footage contracts generated the remaining 37% of our revenues and 62% of our operating margin. The average revenue per rig day worked by the division during 2003 was $12,241.

Rocky Mountain District. Our Rocky Mountain district provides drilling services in the market area which consists of Wyoming, Colorado, northwest Utah and northern New Mexico. We began operations in the Rocky Mountain market in June 2001 and currently have four marketed rigs in this district. Two of these rigs are 3,000 horsepower or larger diesel electric rigs while the other two rigs are diesel electric 1,500 horsepower rigs. Daywork contracts generated 100% of the revenue and operating margin in this market area and the average revenue per rig day worked in the district during 2003 was $13,206. Currently, we have three rigs working in this district. We continue to look for opportunities to expand our market presence in this area.

West Texas District. Our West Texas district provides drilling services in West Texas and Southeast New Mexico. We began operations in West Texas in October 2001. Since that time, we have increased the number of marketed rigs in this district to six diesel electric rigs. During 2003, we averaged five rigs working under daywork contracts, with an average revenue per rig day worked of $9,856.

Cold Stacked Rigs and Rigs Held for Refurbishment

We have the ability to return all 22 cold-stacked rigs to work at an estimated aggregate cost of $2.5 million to $3.0 million, which would bring our marketed fleet to 102 rigs. In addition, we have 15 rigs held for future refurbishment that could be returned to service for an average of approximately $5.0 million per rig, excluding drill pipe and drill collars. The actual number of rigs reactivated in 2004, if any, and in the future will depend upon many factors, including our estimation of existing and anticipated demand and dayrates, our success in bidding for domestic contracts, including term contracts, and the timing of the reactivations. The actual cost of reactivating these rigs would also depend upon the specific customer requirements and to the extent that we choose to upgrade these rigs.

Contracts

Our contracts for drilling oil and natural gas wells are obtained either through competitive bidding or as a result of negotiations with customers. Contract terms offered by us are generally dependent on the complexity and risk of operations, on-site drilling conditions, type of equipment used and the anticipated duration of the work to be performed. Generally, drilling contracts are for a single well. The majority of our drilling contracts are typically subject to termination by the customer on short notice with little or no penalty. Our drilling contracts generally provide for compensation on either a daywork, turnkey or footage basis.

Daywork Contracts. Under daywork drilling contracts, we provide a drilling rig with required personnel to our customer who supervises the drilling of the well. We are paid based on a fixed rate per day while the rig is utilized. Daywork drilling contracts specify the equipment to be used, the size of the hole and the depth of the well. Under a daywork drilling contract, the customer bears a large portion of out-of-pocket costs of drilling. The dayrate we receive is not dependent on the usual risks associated with drilling, such as time delays for various reasons, including stuck drill pipe or blowouts.

We sometimes enter into term contracts to provide drilling services on a daywork basis. Typically, the length of our term contracts have ranged from six months to two years. They have usually included a per rig day termination rate approximately equal to our daily operating margin under the contract. We seek term contracts with our customers when we believe that those contracts may mitigate the financial impact to us of a decline in dayrates during the period in which the term contract is in effect. During late 2001 and 2002, the use of term contracts enabled us to maintain margins that proved to be higher than was attainable during 2002 and 2003. We also have used term contracts to contractually assure that we receive sufficient cash flow to recover the costs of improvements we make to the rigs under the term contract, particularly when those improvements are requested by the customer.

Turnkey Contracts. Under a turnkey contract, we contract to drill a well to an agreed upon depth under specified conditions for a fixed price, regardless of the time required or the problems encountered in drilling the well. We provide technical expertise and engineering services, as well as most of the materials required for the well, and are compensated when the contract terms have been satisfied. Turnkey contracts afford an opportunity to earn a higher margin than would normally be available on daywork or footage contracts if the contract can be completed without complications.

The risks to us under a turnkey contract are substantially greater than on a daywork basis because we assume most of the risks associated with drilling operations generally assumed by the operator in a daywork contract, including the risk of blowout, loss of hole, stuck drill pipe, machinery breakdowns, abnormal drilling conditions and risks associated with subcontractors' services, supplies, cost escalation and personnel. We employ or contract for engineering expertise to analyze seismic, geologic and drilling data to identify and reduce many of the drilling risks assumed by us. We use the results of this analysis to evaluate the risks of a proposed contract and seek to account for such risks in our bid preparation. We believe that our operating experience, qualified drilling personnel, risk management program, internal engineering expertise and access to proficient third party engineering contractors have allowed us to reduce the risks inherent in turnkey drilling operations. We also maintain insurance coverage against some but not all drilling hazards.

Footage Contracts. Under footage contracts, we are paid a fixed amount for each foot drilled, regardless of the time required or certain problems encountered in drilling the well. We typically pay more of the out-of-pocket costs associated with footage contracts than under daywork contracts. Similar to a turnkey contract, the risks to us on a footage contract are greater than under a daywork contract because we assume some of the risks associated with drilling operations generally assumed by the operator in a daywork contract, including the risk of blowout, loss of hole, stuck drill pipe, machinery breakdowns, and risks associated with subcontractors' services, supplies, cost escalation and personnel. Generally, the overall risk we assume is not as great as under turnkey contracts. As with turnkey contracts, we manage additional risk through the use of engineering expertise and bid the footage contracts accordingly. We also maintain insurance coverage against certain drilling hazards.

Customers and Marketing

Our contract drilling customers include independent producers and major oil and gas companies. In 2003, 35% of our revenue came from major oil and gas companies and large independent producers, while the remaining 65% came from other independents. For the year ended December 31, 2003, no individual customer accounted for more than 10% of our revenues. We primarily market our drilling rigs on a regional basis through employee sales representatives. These sales representatives utilize personal contacts and industry periodicals and publications to determine which operators are planning to drill oil and natural gas wells in the immediate future. Once we have been placed on the "bid list" for an operator, we will typically be given the opportunity to bid on all future wells for that operator in the area.

From time to time we also enter into informal, nonbinding commitments with our customers to provide drilling rigs for future periods at agreed upon rates plus fuel and mobilization charges, if applicable, and escalation provisions. This practice is customary in the land drilling business during times of increasing rig demand. Although neither we nor the customer are legally required to honor these commitments, we generally satisfy such commitments in order to maintain good customer relations.

Insurance

Our operations are subject to the many hazards inherent in the drilling business, including, for example, blowouts, cratering, fires, explosions and adverse weather. These hazards could cause personal injury, death, suspend drilling operations or seriously damage or destroy the equipment involved and could cause substantial damage to producing formations and surrounding areas. Damage to the environment could also result from our operations, particularly through oil spillage and extensive, uncontrolled fires. As a protection against operating hazards, we maintain insurance coverage, including comprehensive general liability, workers' compensation insurance, property casualty insurance on our rigs and drilling equipment, and "control of well" insurance. In addition, we have commercial excess liability insurance, to cover general liability, auto liability and workers' compensation claims which are higher than the maximum coverage provided under those policies. The table below and the discussion that follows highlights these coverages.

Coverage	Limit per Occurrence	Aggregate Limit	Deductible/ Self-Insured Retention per Occurrence
Workers' compensation/ Employer liability	Statutory[1]/$1.0 million	None	$350,000
Automobile liability	$1.0 million	None	$350,000
Commercial general liability	$1.0 million	$2.0 million	$250,000
Commercial excess liability	$10.0 million	$10.0 million	Underlying insurance
Commercial excess liability	$65.0 million	$65.0 million	Underlying insurance

(1) Workers' compensation policy limits vary depending on the laws of the particular states in which we operate.

Our property casualty insurance coverage for damage to our rigs and drilling equipment is based on our estimate of the cost of comparable used equipment to replace the insured property. There is a $125,000 maintenance deductible per occurrence for losses on our rigs. In addition, there is a deductible of $850,000 in the aggregate over the policy period, exclusive of the maintenance deductible. There is a $25,000 deductible per occurrence on other equipment. We do not have insurance coverage against loss of earnings resulting from damage to our rigs.

We also maintain insurance coverage to protect against certain hazards inherent in our turnkey and footage contract drilling operations. This insurance covers "control of well" (including blowouts above and below the surface), cratering, seepage and pollution and care, custody and control. Our current insurance provides $3.0 million coverage per occurrence for care, custody and control, and coverage per occurrence for control of well, cratering, seepage and pollution associated with drilling operations of either $10.0 million or $20.0 million, depending upon the area in which the well is drilled and its target depth. Each form of coverage provides for a deductible that we must meet, as well as a maximum limit of liability. Each casualty is an occurrence, and there may be more than one such occurrence on a well, each of which would be subject to a separate deductible.

No assurances can be given that we will be able to maintain the above-mentioned insurance types and/or the amounts of coverage that we believe to be adequate. Also, there are no assurances that these types of coverages will be available in the future. Our insurance may not be sufficient to protect us against liability for all consequences of well disasters, extensive fire damage, damage to the environment, damage to producing formations or other hazards. The rising cost and/or availability of certain types of insurance could have an adverse effect on our financial condition and results of operations.

Certain Risks

A material or extended decline in expenditures by the oil and gas industry, due to a decline or volatility in oil and gas prices, a decrease in demand for oil and gas or other factors, would reduce our revenue and income.

As a supplier of land drilling services, our business depends on the level of drilling activity by oil and gas exploration and production companies operating in the geographic markets where we operate. The number of wells they choose to drill is strongly influenced by past trends in oil and natural gas prices, current prices and their outlook for future prices. Low oil and natural gas prices, or the perception among oil and gas companies that prices are likely to decline, can materially and adversely affect us in many ways, including:

- our revenues, cash flows and earnings;
- the fair market value of our rig fleet, which in turn could trigger a writedown of the carrying value of these assets for accounting purposes;
- our ability to maintain or increase our borrowing capacity;
- our ability to obtain additional capital to finance our business and make acquisitions, and the cost of that capital; and
- our ability to retain skilled rig personnel who we would need in the event of an increase in the demand for our services.

Depending on the market prices of oil and natural gas, oil and gas exploration and production companies may cancel or curtail their drilling programs, thereby reducing demand for our services. Even during periods when prices for oil and natural gas are high, companies exploring for oil and natural gas may cancel or curtail their drilling programs for a variety of other reasons beyond our control. Any reduction in the demand for drilling services may materially erode dayrates, the prices we receive for our turnkey drilling services and the utilization rates for our rigs, any of which could adversely affect our financial results. Oil and natural gas prices have been volatile historically and, we believe, will continue to be so in the future. Many factors beyond our control affect oil and natural gas prices, including:

- weather conditions in the United States and elsewhere;
- economic conditions in the United States and elsewhere;
- actions by OPEC, the Organization of Petroleum Exporting Countries;
- political instability in the Middle East, Venezuela and other major producing regions;
- governmental regulations, both domestic and foreign;
- the pace adopted by foreign governments for exploration of their national reserves; and
- the overall supply and demand for oil and natural gas.

An economic downturn may adversely affect our business.

An economic downturn may cause reduced demand for petroleum-based products and natural gas. In addition, many oil and natural gas production companies often reduce or delay expenditures to reduce costs, which in turn may cause a reduction in the demand for our services during these periods. The number of active land drilling rigs may be indicative of demand for services that we provide. If the economic environment worsens, our business, financial condition and results of operations may be further adversely impacted.

The intense price competition and cyclical nature of our industry could have an adverse effect on our revenues and profitability.

The contract drilling business is highly competitive with numerous industry participants. The drilling contracts we compete for are usually awarded on the basis of competitive bids. We believe pricing and rig availability are the primary factors considered by our potential customers in determining which drilling contractor to select. We believe other factors are also important. Among those factors are:

- the type and condition of drilling rigs;
- the quality of service and experience of rig crews;
- the safety record of the company and the particular drilling rig;
- the offering of ancillary services; and
- the ability to provide drilling equipment adaptable to, and personnel familiar with, new technologies and drilling techniques.

While we must generally be competitive in our pricing, our competitive strategy emphasizes the quality of our equipment, the safety record of our rigs and the experience of our rig crews to differentiate us from our competitors. This strategy is less effective during an industry downturn as lower demand for drilling services intensifies price competition and makes it more difficult for us to compete on the basis of factors other than price.

The contract drilling industry historically has been cyclical and has experienced periods of low demand, excess rig supply, and low dayrates, followed by periods of high demand, short rig supply and increasing dayrates. Periods of excess rig supply intensify the competition in our industry and often result in rigs being idle.

There are numerous competitors in each of the markets in which we compete. In all of those markets, an oversupply of rigs can cause greater price competition. Contract drilling companies compete primarily on a regional basis, and the intensity of competition may vary significantly from region to region at any particular time. If demand for drilling services improves in a region where we operate, our competitors might respond by moving in suitable rigs from other regions. An influx of rigs from other regions could rapidly intensify competition and make any improvement in demand for drilling rigs short-lived.

We face competition from competitors with greater resources.

Some of our competitors have greater financial and human resources than do we. Their greater capabilities in these areas may enable them to:

- better withstand industry downturns;
- compete more effectively on the basis of price and technology;
- retain skilled rig personnel; and
- build new rigs or acquire and refurbish existing rigs to be able to place rigs into service more quickly than we can.

Our drilling operations involve operating hazards which if not adequately insured or indemnified against could adversely affect our results of operations and financial condition.

Our operations are subject to the usual hazards inherent in the land drilling business including the risks of:

- blowouts;
- reservoir damage;
- cratering;
- fires, pollution and explosions;
- collapse of the borehole;
- lost or stuck drill strings; and
- damage or loss from natural disasters.

If these drilling hazards occur they can produce substantial liabilities to us which include:

- suspension of drilling operations;
- damage to the environment;
- damage to, or destruction of, our property and equipment and that of others;
- personal injury and loss of life; and
- damage to producing or potentially productive oil and natural gas formations through which we drill.

We attempt to obtain indemnification from our customers by contract for certain of these risks under daywork contracts but are not always able to do so. We also seek to protect ourselves from some but not all operating hazards through insurance coverage. The indemnification we receive from our customers and our own insurance coverage may not, however, be sufficient to protect us against liability for all consequences of disasters, personal injury and property damage. Additionally, our insurance coverage generally provides that we bear a portion of the claim through substantial insurance coverage deductibles. Our insurance or indemnification arrangements may not adequately protect us against liability from all of the hazards of our business. If we were to incur a significant liability for which we were not fully insured or indemnified, it could adversely affect on our financial position and results of operations.

Our cost of insurance increased significantly in 2003 compared to prior years, which we believe is consistent with the experience of most companies in our industry. When we renew our current insurance policies, the premiums we pay may again increase, which will increase our operating costs. Additionally, we may be unable to obtain or renew insurance coverage of the type and amount we desire at reasonable rates.

Business acquisitions entail numerous risks and may disrupt our business, dilute shareholder value or distract management attention.

As part of our business strategy, we plan to consider acquisitions of, or significant investments in, businesses and assets that are complementary to ours. Any acquisition that we complete could have a material adverse affect on our operating results and/or the price of our securities. Acquisitions involve numerous risks, including:

- unanticipated costs and liabilities;
- difficulty of integrating the operations and assets of the acquired business;
- our ability to properly access and maintain an effective internal control environment over an acquired company, in order to comply with the recently adopted and pending public reporting requirements;
- potential loss of key employees and customers of the acquired companies; and
- an increase in our expenses and working capital requirements.

We may incur substantial indebtedness to finance future acquisitions and also may issue equity securities or convertible securities in connection with any such acquisitions. Debt service requirements could represent a significant burden on our results of operations and financial condition and the issuance of additional equity could be dilutive to our existing stockholders. Also, continued growth could divert the attention of our management and other employees from our day-to-day operations and the development of new business opportunities.

Our operations are subject to environmental laws that may expose us to liabilities for noncompliance, which may adversely affect us.

Many aspects of our operations are subject to domestic laws and regulations. For example, our drilling operations are typically subject to extensive and evolving laws and regulations governing:

- environmental quality;
- pollution control; and
- remediation of environmental contamination.

Our operations are often conducted in or near ecologically sensitive areas, such as wetlands, which are subject to special protective measures and which may expose us to additional operating costs and liabilities for noncompliance with applicable laws. The handling of waste materials, some of which are classified as hazardous substances, is a necessary part of our operations. Consequently, our operations are subject to stringent regulations relating to protection of the environment and waste handling which may impose liability on us for our own noncompliance and, in addition, that of other parties without regard to whether we were negligent or otherwise at fault. Compliance with applicable laws and regulations may require us to incur significant expenses and capital expenditures which could have a material and adverse effect on our operations by increasing our expenses and limiting our future contract drilling opportunities.

We have had only two profitable years since 1991.

We have a history of losses with only two profitable years since 1991. In 1997, we had net income of $10.2 million and in 2001 we had net income of $68.5 million. Our ability to achieve profitability in the future will depend on many factors, but primarily on the utilization rates for our rigs and the rates we charge for them.

Unexpected cost overruns on our turnkey and footage drilling jobs could adversely affect us.

We have historically derived a significant portion of our revenues and operating margin from turnkey and footage drilling contracts and we expect that they will continue to represent a significant component of our revenues. The occurrence of operating cost overruns on our turnkey and footage jobs could have a material adverse effect on our financial position and results of operations. Under a typical turnkey or footage drilling contract, we agree to drill a well for our customer to a specified depth and under specified conditions for a fixed price. We typically provide technical expertise and engineering services, as well as most of the equipment required for the drilling of turnkey and footage wells. We often subcontract for related services. Under typical turnkey drilling arrangements, we do not receive progress payments and are entitled to be paid by our customer only after we have performed the terms of the drilling contract in full. For these reasons, the risk to us under turnkey and footage drilling contracts is substantially greater than for wells drilled on a daywork basis because we must assume most of the risks associated with drilling operations that are generally assumed by our customer under a daywork contract.

We could be adversely affected if shortages of equipment, supplies or personnel occur.

While we are not currently experiencing any shortages, from time to time there have been shortages of drilling equipment and supplies which we believe could reoccur. During periods of shortages, the cost and delivery times of equipment and supplies are substantially greater. In the past, in response to such shortages, we have entered into agreements with various suppliers and manufacturers that enabled us to reduce our exposure to price increases and supply shortages. Although we have formed many informal supply arrangements with equipment manufacturers and suppliers, we cannot assure you that we will be able to maintain existing arrangements. Shortages of drilling equipment or supplies could delay and adversely affect our ability to return to service our rigs held for future refurbishment and obtain contracts for our marketed rigs, which could have a material adverse effect on our financial condition and results of operations.

Although we have not encountered material difficulty in hiring and retaining qualified rig crews, such shortages have occurred in the past in our industry. We may experience shortages of qualified personnel to operate our rigs, which could have a material adverse effect on our financial condition and results of operations.

Our indentures and our credit agreement may prohibit us from participation in certain transactions that we may consider advantageous.

The indentures under which we issued our 8⅞% Senior Notes due 2007 and 8⅞% Senior Notes due 2007, Series B (together, the "8⅞% Notes") contain restrictions on our ability and the ability of certain of our subsidiaries to engage in certain types of transactions. These restrictive covenants may adversely affect our ability to pursue business acquisitions. These include covenants which may prohibit or limit our ability to:

- incur additional indebtedness;
- pay dividends or make other restricted payments;
- repurchase our equity securities;
- sell material assets;
- grant or permit liens to exist on our assets;

- enter into sale and lease-back transactions;
- make certain investments;
- enter into transactions with related persons; and
- engage in lines of business unrelated to our core land drilling business.

Our subsidiary, Grey Wolf Drilling Company L.P., has entered into a credit facility that also contains covenants restricting our ability to undertake many of the same types of transactions and contains financial ratio covenants when certain conditions are met. They may also limit our ability to respond to changes in market conditions. Our ability to meet the financial ratio covenants of our credit agreement and indentures can be affected by events and conditions beyond our control and we may be unable to meet those tests (see Note 4 to the consolidated financial statements).

Our credit facility contains default terms that effectively cross default with any of our other debt agreements, including the indentures for our 8⅞% Notes and our 3.75% Contingent Convertible Notes due May 2023 (the "3.75% Notes"). Thus, if we breach the covenants in the indentures for our 8⅞% Notes, it could cause our default under our 8⅞% Notes, our credit facility and, possibly, other then outstanding debt obligations owed by us. If the indebtedness under our credit facility or other indebtedness owed by us is more than $10.0 million and is not paid when due, or is accelerated by the holders of the debt, then an event of default under the indentures covering our 8⅞% Notes would occur. If circumstances arise in which we are in default under our various credit agreements, our cash and other assets may be insufficient to repay our indebtedness. We may in the future incur additional indebtedness that may contain additional covenants that may be more restrictive than our current covenants.

We have a significant amount of indebtedness and could incur additional indebtedness, which could materially and adversely affect our financial condition and results of operations.

We have now and will continue to have a significant amount of indebtedness. On December 31, 2003, our total long-term indebtedness was approximately $235.0 million in principal amount, (primarily consisting of $150.0 million in principal amount of our 3.75% Notes and $85.0 million in principal amount of 8⅞% Notes).

Our substantial indebtedness could:

- increase our vulnerability to general adverse economic and industry conditions;
- require us to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness thereby reducing the availability of our cash flow to fund working capital, capital expenditures and other general corporate purposes;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- place us at a competitive disadvantage compared to our competitors that have less debt; and
- limit our ability to borrow additional funds.

Neither the indenture governing our 3.75% Notes nor the terms of our 3.75% Notes limit our ability to incur additional indebtedness, including senior indebtedness, or to grant liens on our assets. We and our subsidiaries may incur substantial additional indebtedness and liens on our assets in the future.

Our existing senior indebtedness is, and any senior indebtedness we incur will be, effectively subordinated to any present or future obligations to secured creditors and liabilities of our subsidiaries.

Substantially all of our assets and the assets of our subsidiaries, including our drilling equipment and the equity interest in our subsidiaries, are pledged as collateral under our credit facility. Our credit facility is also secured by our guarantee and the guarantees of our subsidiaries. The 3.75% Notes and the 8⅞% Notes are, and any senior indebtedness we incur will be, effectively subordinated to all of our and our subsidiaries' existing and future secured indebtedness, including any future indebtedness incurred under our credit facility. As of February 10, 2004, we had the ability to borrow approximately $58.6 million under our credit facility (after reductions for undrawn outstanding standby letters of credit of $16.4 million). In addition, the 3.75% Notes and the 8⅞% Notes are effectively subordinated to the claims of all of the creditors, including trade creditors and tort claimants, of our subsidiaries.

To service our indebtedness, we will require a significant amount of cash. Our ability to generate cash depends on many factors beyond our control.

Our operating activities did not provide net cash sufficient to pay our debt service obligations for the year ended December 31, 2003 and we cannot assure you that we will be able to generate sufficient cash flow in the future. Our ability to make payments on and to refinance our indebtedness and to fund planned capital expenditures will depend on our ability to generate cash in the future. This, to a large extent, is subject to general economic, financial, competitive, regulatory and other factors that are beyond our control.

Our reported earnings per share may be more volatile because of the conversion contingency provision of the 3.75% Notes.

Holders of the 3.75% Notes may convert such notes prior to the maturity date into shares of our common stock in the following circumstances:

- during any calendar quarter, if the closing sale price per share of our common stock for at least 20 trading days in the period of 30 consecutive trading days ending on the last trading day of the calendar quarter preceding the quarter in which the conversion occurs, is more than 110% of the conversion price per share ($7.10 per share) on that 30th trading day;
- if we have called the 3.75% Notes for redemption;
- during any period that the credit ratings assigned to the 3.75% Notes by both Moody's Investors Service ("Moody's") and Standard & Poors Ratings Group ("S&P") are reduced below B1 and B+, respectively;
- if neither Moody's nor S&P is rating the 3.75% Notes;
- during the five trading day period immediately following any nine consecutive trading day period in which the average trading price per $1,000 principal amount of the 3.75% Notes for each day of such period was less than 95% of the product of the closing sale price per share of our common stock on that day multiplied by the number of shares of our common stock issuable upon conversion of $1,000 principal amount of the 3.75% Notes; or
- upon the occurrence of specified corporate transactions, including a change in control.

Until one of these contingencies is met, the shares underlying the 3.75% Notes are not included in the calculation of basic or diluted earnings per share. Should one of these contingencies be met, earnings per share could decrease, depending on the level of net income, as a result of the inclusion of the underlying shares in the earnings per share calculation. Volatility in our stock price could cause this condition to be met in one quarter and not in a subsequent quarter, increasing the volatility of diluted earnings per share.

Our indentures for the 8⅞% Notes and our credit agreement restrict our ability to pay dividends.

We have never declared a cash dividend on our common stock and do not expect to pay cash dividends on our common stock for the foreseeable future. We expect that all cash flow generated from our operations in the foreseeable future will be retained and used to develop or expand our business, pay debt service and reduce outstanding indebtedness. Furthermore, the terms of our credit facility prohibit the payment of dividends without the prior written consent of the lenders and the terms of the indentures under which our 8⅞% Notes are issued also restrict our ability to pay dividends under certain conditions.

Certain provisions of our organizational documents, securities and credit agreement have anti-takeover effects which may prevent our shareholders from receiving the maximum value for their shares.

Our articles of incorporation, bylaws, securities and credit agreement contain certain provisions that may delay or prevent entirely a change of control transaction not supported by our board of directors, or any transaction which may have that general effect. These provisions include:

- classification of our board of directors into three classes, with each class serving a staggered three year term;
- giving our board of directors the exclusive authority to adopt, amend or repeal our bylaws and thus prohibiting shareholders from doing so;
- requiring our shareholders to give advance notice of their intent to submit a proposal at the annual meeting; and
- limiting the ability of our shareholders to call a special meeting and act by written consent.

Additionally, the indentures under which our 3.75% Notes and 8⅞% Notes are issued require us to offer to repurchase the 3.75% Notes and 8⅞% Notes then outstanding at a purchase price equal to 100% and 101%, respectively, of the principal amount plus accrued and unpaid interest to the date of purchase in the event that we become subject to a change of control, as defined in the indentures. This feature of the indentures could also have the effect of discouraging potentially attractive change of control offers.

Furthermore, we have adopted a shareholder rights plan which may have the effect of impeding a hostile attempt to acquire control of us.

Large amounts of our common stock may be resold into the market in the future which could cause the market price of our common stock to drop significantly, even if our business is doing well.

As of February 10, 2004, 181.4 million shares of our common stock were issued and outstanding. An additional 10.2 million shares of our common stock were issuable upon exercise of outstanding stock options (of which 5.4 million shares are currently exercisable) and 23.3 million shares were issuable upon conversion of the 3.75% Notes, once a contingency is met (see Note 4 to the consolidated financial statements). The market price of our common stock could drop significantly if future sales of substantial amounts of our common stock occur, or if the perception exists that substantial sales may occur.

Employees

At February 10, 2004, we had approximately 1,750 employees. None of our employees are subject to collective bargaining agreements, and we believe our employee relations are satisfactory.

Forward-Looking Statements

This annual report on Form 10-K contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included in this report are forward-looking statements, including statements regarding the following:

- business strategy;
- demand for our services;
- 2004 rig activity and financial results;
- reactivation and cost of reactivation of non-marketed rigs;
- projected dayrates and operating margins per rig day;
- rigs expected to be engaged in turnkey and footage operations;
- projected tax benefit rate;
- wage rates and retention of employees;
- sufficiency of our capital resources and liquidity; and
- depreciation and capital expenditures in 2004.

Although we believe the forward-looking statements are reasonable, we cannot assure you that these statements will prove to be correct. We have based these statements on assumptions and analyses in light of our experience and perception of historical trends, current conditions, expected future developments and other factors we believe were appropriate when the statements were made. In addition to those risks described above under "Certain Risks" other factors that could cause actual results to differ materially from our expectations include:

- fluctuations in prices and demand for oil and natural gas;
- fluctuations in levels of oil and natural gas exploration and development activities;
- fluctuations in the demand for contract land drilling services;
- the existence and competitive responses of our competitors;
- uninsured or underinsured casualty losses;
- technological changes and developments in the industry;
- the existence of operating risks inherent in the contract land drilling industry;
- U.S. and global economic conditions;
- the availability and terms of insurance coverage;
- the ability to attract and retain qualified personnel;
- unforeseen operating costs such as cost for environmental remediation and turnkey and footage cost overruns; and
- weather conditions.

Our forward-looking statements speak only as of the date specified in such statements or, if no date is stated, as of the date of this report. Grey Wolf expressly disclaims any obligation or undertaking to release publicly any updates or revisions to any forward-looking statement contained in this report to reflect any change in our expectations or with regard to any change in events, conditions or circumstances on which our forward-looking statements are based.

ITEM 2. PROPERTIES

Drilling Equipment

An operating land drilling rig consists of engines, drawworks, mast, substructure, pumps to circulate drilling fluid, blowout preventers, drill pipe and related equipment. Domestically, land rigs generally operate with crews of four to six people.

Our rig fleet consists of several rig types to meet the demands of our customers in each of the markets we serve. Our rig fleet consists of two basic types of drilling rigs, mechanical and diesel electric. Mechanical rigs transmit power generated by a diesel engine directly to an operation (for example the drawworks or mud pumps on a rig) through a compound consisting of chains, gears and hydraulic clutches. Diesel electric rigs are further broken down into two subcategories, direct current rigs and Silicon Controlled Rectifier ("SCR") rigs. Direct current rigs transmit the power generated by a diesel engine to a direct current generator. This direct current electrical system then distributes the electricity generated to direct current motors on the drawworks and mud pumps. An SCR rig's diesel engines drive alternating current generators and this alternating current can be transmitted to use for rig lighting and rig quarters or converted to direct current to drive the direct current motors on the rig. We own nine direct current diesel electric rigs and 52 SCR diesel electric rigs.

We also own 17 mechanical rigs and one diesel electric rig that are trailer-mounted for greater mobility. We believe that trailer-mounted rigs and 1,500 to 2,000 horsepower diesel electric rigs are in highest demand in the South Texas market. Trailer-mounted rigs are more mobile than conventional rigs, thus decreasing the time and expense to the customer of moving the rig to and from the drill site. Under ordinary conditions, trailer-mounted rigs are capable of drilling an average of two 10,000 foot wells per month.

We also utilize top drives in our drilling operations. A top drive allows drilling with 90-foot lengths of drill pipe rather than 30-foot lengths, thus reducing the number of required connections in the drill string. A top drive also permits rotation of the drill string while moving in or out of the hole. These characteristics increase drilling speed, personnel safety and drilling efficiency, and reduce the risk of the drill string sticking during operations. At February 10, 2004, we owned 15 top drives.

We generally deploy our rig fleet among our divisions and districts based on the types of rigs preferred by our customers for drilling in the geographic markets served by our divisions and districts. The following table summarizes the rigs we own as of February 10, 2004:

	Maximum Rated Depth Capacity (1)				
	Under 10,000'	10,000' to 14,999'	15,000' to 19,999'	20,000' and Deeper	Total
Marketed					
Ark-La-Tex					
Diesel Electric	–	1	5	5	11
Trailer-Mounted	–	1	–	–	1
Mechanical	–	2	3	2	7
Gulf Coast					
Diesel Electric	–	–	1	17	18
Mechanical	–	1	2	–	3
South Texas					
Diesel Electric	–	1	6	8	15
Trailer-Mounted	–	9	–	1	10(2)
Mechanical	–	4	–	1	5
Rocky Mountain					
Diesel Electric	–	–	–	4	4
West Texas					
Diesel Electric	–	–	2	4	6
Total Marketed	–	19	19	42	80
Non-marketed					
Diesel Electric	–	–	–	7	7
Trailer-Mounted	1	6	–	–	7
Mechanical	1	11	8	3	23
Total Non-Marketed	2	17	8	10	37
Total Rig Fleet	2	36	27	52	117

(1) The actual drilling capacity of a rig may be less than its rated capacity due to numerous factors, such as the length of the drill string and casing size. The intended well depth and the drill site conditions determine the length of the drill string and other equipment needed to drill a well.

(2) Includes one diesel electric rig.

Facilities

The following table summarizes our significant real estate:

Location	Interest	Uses
Houston, Texas	Leased	Corporate Office
Alice, Texas	Owned	Division Office, Rig Yard, Truck Yard
Eunice, Louisiana	Owned	Division Office, Rig Yard
Haughton, Louisiana	Owned	Rig Yard
Shreveport, Louisiana	Leased	Division Office
Shreveport, Louisiana	Owned	Rig Yard, Truck Yard
Casper, Wyoming	Leased	District Office
Midland, Texas	Leased	District Office

We lease approximately 22,700 square feet of office space in Houston, Texas for our principal corporate offices at a cost of approximately $41,500 per month. We believe that all our facilities are in good operating condition and that they are adequate for their present uses.

ITEM 3. LEGAL PROCEEDINGS

We are involved in litigation incidental to the conduct of our business, none of which we believe is, individually or in the aggregate, material to our consolidated financial condition or results of operations.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED SHAREHOLDER MATTERS

Market Data

Our common stock is listed and traded on the American Stock Exchange ("AMEX") under the symbol "GW." As of February 13, 2004, we had 976 shareholders of record. The following table sets forth the high and low closing prices of our common stock on the AMEX for the periods indicated:

	High	Low
Period from January 1, 2004 to February 10, 2004	$ 4.31	$ 3.74
Year Ended December 31, 2003		
Quarter ended March 31, 2003	4.50	3.50
Quarter ended June 30, 2003	4.96	3.88
Quarter ended September 30, 2003	4.19	3.22
Quarter ended December 31, 2003	3.89	3.16
Year Ended December 31, 2002		
Quarter ended March 31, 2002	4.07	2.69
Quarter ended June 30, 2002	5.01	3.72
Quarter ended September 30, 2002	4.08	2.78
Quarter ended December 31, 2002	4.42	3.15

We have never declared or paid cash dividends on our common stock and do not expect to pay cash dividends in 2004 or for the foreseeable future. We anticipate that all cash flow generated from operations in the foreseeable future will be retained and used to develop or expand our business, pay debt service and reduce outstanding indebtedness. Any future payment of cash dividends will depend upon our results of operations, financial condition, cash requirements and other factors deemed relevant by our board of directors.

The terms of our credit facility prohibit the payment of dividends without the prior written consent of the lender and the terms of the Indentures under which our 8⅞% Notes are issued also restrict our ability to pay dividends under certain conditions.

On February 10, 2004, the last reported sales price of our common stock on the AMEX was $4.25 per share.

ITEM 6. SELECTED FINANCIAL DATA

	Years Ended December 31,				
	2003	2002	2001	2000	1999
	(Amounts in thousands, except per share amounts)				
Revenues (1)	$ 285,974	$ 250,260	$ 433,739	$ 276,758	$ 148,465
Net income (loss)	(30,200)	(21,476)	68,453	(8,523)	(41,262)
Net income (loss) per common share - basic and diluted	(0.17)	(0.12)	0.38	(0.05)	(0.25)
Total assets (1)	529,078	590,623	625,471	512,370	453,852
Senior and contingent convertible notes & other long-term debt	234,898	249,613	250,695	249,851	249,962

(1) Presentation revised to give effect to reclassification of certain items to conform to the presentation in 2002 and 2003 (see Note 1 to consolidated financial statements).

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion should be read in conjunction with our consolidated financial statements included elsewhere herein. All significant intercompany transactions have been eliminated.

Overview

We are a leading provider of contract land drilling services in the United States with a fleet of 117 rigs, of which 80 rigs are currently marketed. Our customers include independent producers and major oil and gas companies. We conduct all of our operations through our subsidiaries in the Ark-La-Tex, Gulf Coast, Mississippi/Alabama, South Texas, West Texas and Rocky Mountain drilling markets. Our drilling contracts generally provide compensation on a daywork, turnkey or footage basis (see Item 1. Business).

Our business is cyclical and our financial results depend upon several factors. These factors include the overall demand for land drilling services, the level of demand for turnkey and footage services, the demand for deep versus shallow drilling services, the dayrates we receive for our services and our success drilling turnkey and footage wells.

Rig Activity

After a modest increase in our number of rigs working in the first quarter of 2003, our rig count has remained relatively stable. Our premium rig fleet is biased towards deep gas drilling and we believe that our activity and market share have been adversely affected by the general lack of deep drilling in this current industry cycle.

The table below shows the average number of land rigs working in the United States according to the Baker Hughes rotary rig count and the average number of our rigs working.

	2002					2003					2004
Domestic Land Rig Count	Q-1	Q-2	Q-3	Q-4	Full Year	Q-1	Q-2	Q-3	Q-4	Full Year	Q-1 to Date
Baker Hughes	679	683	722	723	695	773	903	964	988	880	995
Grey Wolf	56	54	55	54	55	59	60	62	62	61	63

Drilling Contract Bid Rates

Daywork dayrates are generally driven by utilization. Our daywork bid rates ranged between $7,000 and $8,500 per rig day during the fourth quarter of 2002. However, as the land rig count has increased, our leading edge bid rates have risen to between $8,000 and $9,500 per rig day. All leading edge bid rates exclude fuel and top drives. We believe that the drilling contract dayrates have been affected by an increase in the number of rigs available, as well as by the focus by our competitors on market share rather than higher dayrates.

In addition to our fleet of drilling rigs, we currently own 15 top drives for which our current bid rates range from $1,500 to $2,000 per day. Bid rates for our top drives are in addition to the above stated bid rates for our rigs.

Turnkey and Footage Contract Activity

Turnkey and footage work continues to be an important part of our business and operating strategy. Our engineering and operating expertise allow us to provide this service to our customers and has historically provided higher revenues and operating margins per rig day worked than under daywork contracts. However, we are typically required to bear additional operating costs (such as drill bits) that would otherwise be paid by the customer under daywork contracts. In 2003, our turnkey and footage operating margin (revenues less drilling operations expenses) was $6,094 per rig day compared to a daywork operating margin of $1,106 per rig day, and our turnkey and footage revenue was $31,087 per rig day compared to $9,562 per rig day for daywork. For the year ended December 31, 2003, turnkey and footage work represented 50% of our operating margin and 16% of total days worked compared to 20% of our operating margin and 9% of total days worked in 2002.

The operating margins generated on turnkey and footage contracts vary widely based upon a number of factors, including the location of the contracted work as well as the depth and level of complexity of the wells drilled. The demand for drilling services under turnkey and footage contracts has historically been greater during periods of overall lower demand. While demand has been somewhat higher as evidenced by the increase in rig count, the demand for turnkey services has not declined. We believe this is due in large part to current daywork rates which have increased only slightly despite the increase in rig count.

Fourth Quarter Financial Results

The fourth quarter of 2003 exceeded our previous guidance for the quarter. Our previous guidance for the fourth quarter was a loss per share of $0.03 on a diluted basis and an operating margin of $10.5 million or approximately $1,700 per rig day. Our earnings per share on a diluted basis was actually $0.00 for the fourth quarter and our total operating margin (revenues less drilling operations expenses) was $19.3 million, or $3,366 per rig day. The fourth quarter operating margin consists of $9.5 million from turnkey contracts, $6.7 million from daywork contracts, and $3.1 million from the sale of a claim in bankruptcy, against a bankrupt customer, for revenues related to the early termination of a long-term contract.

We exceeded our previous guidance primarily due to a record quarter from our turnkey business and the sale of the claim noted above. We averaged 12 rigs working on turnkey contracts during the fourth quarter, representing 20% of the total rig days and 49% of our operating margin. The operating margin per rig day for turnkey work was $8,448 in the fourth quarter of 2003 compared to $6,123 in the fourth quarter of 2002. This increase is due mainly to the complexity and depth of the turnkey wells drilled in the fourth quarter of 2003. We believe that turnkey work will remain strong in the first quarter of 2004, however, we are not expecting a repeat of the margin earned in the fourth quarter.

First Quarter 2004 Outlook

Based on currently anticipated levels of activity and dayrates, we expect to generate an operating margin of approximately $12.9 million, or $2,100 per rig day for the first quarter of 2004. Net loss per share is expected to be approximately $0.02 on a diluted basis, projecting an annual tax benefit rate of approximately 37%. We expect depreciation expense of approximately $12.9 million and interest expense of approximately $3.7 million in the first quarter of 2004. Capital expenditures for 2004 are currently projected to be $27.0 million to $30.0 million subject to the actual level of rig activity. These projections are forward-looking statements and while we believe our estimates are reasonable, we can give no assurance that such expectations or the assumptions that underlie such assumptions will prove to be correct. We expect to average between eight and 11 rigs working under turnkey and footage contracts during the first quarter of 2004; however, there can be no assurance that we will be able to maintain the current level of activity or operating margins derived from turnkey and footage contracts. See Item 1. Business-Forward-Looking Statements for important factors that could cause actual results to be differ materially from our expectations.

Critical Accounting Policies

Our consolidated financial statements and accompanying notes have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these financial statements require our management to make subjective estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. However, these estimates, judgments and assumptions concern matters that are inherently uncertain. Accordingly, actual amounts and results could differ from these estimates made by management, sometimes materially. Critical accounting policies and estimates are defined as those that are both most important to the portrayal of our financial condition and operating results and require management's most subjective judgments. The accounting policies that we believe are critical are property and equipment, impairment of long-lived assets, revenue recognition, insurance accruals, and income taxes.

Property and Equipment. Property and equipment are stated at cost with depreciation calculated using the straight-line method over the estimated useful lives of the assets. We expense our maintenance and repair costs as incurred. We estimate the useful lives of our assets are between three and fifteen years.

Impairment of Long-Lived Assets. We assess the impairment of our long-lived assets under Statement of Financial Accounting Standards Board ("SFAS") No. 144 "Accounting for the Impairment or Disposal of Long-Lived Assets", whenever events or changes in circumstances indicate that the carrying value may not be recoverable. Such indicators include changes in our business plans, a change in the physical condition of a long-lived asset or the extent or manner in which it is being used, or a severe or sustained downturn in the oil and gas industry. If we determine that a triggering event, such as those described previously, has occurred we perform a review of our rig and rig equipment. Our review is performed by comparing the carrying value of each rig to the estimated undiscounted future net cash flows for that rig. If the carrying value of any rig is more than the estimated undiscounted future net cash flows expected to result from the use of the rig, a write-down of the rig to estimated fair market value must be made. The estimated fair market value is the amount at which an asset could be bought or sold in a current transaction between willing parties. Quoted market prices in active markets are the best estimate of fair market value, however, quoted market prices are generally not available. As a result, fair value must be determined based upon other valuation techniques. This could include appraisals or present value calculations. The calculation of undiscounted future net cash flows and fair market value is based on our estimates and projections.

The demand for land drilling services is cyclical and has historically resulted in fluctuations in rig utilization. The severity and duration of the downturn during 1998 triggered an asset impairment charge of $93.2 million. We believe the contract drilling industry will continue to be cyclical and rig utilization will fluctuate. The likelihood of an asset impairment increases during extended periods of rig inactivity. Each year we evaluate our cold stacked and inventory rigs and determine our intentions for their future use. This evaluation takes into consideration, among other things, the physical condition and marketability of the rig, and projected reactivation or refurbishment cost. If we were to change our intended use of some or all of the rigs, we could be required under SFAS No. 144 to record an impairment charge. During the fourth quarter of 2002, we recorded a pre-tax, non-cash asset impairment charge of $3.5 million after performing such a review. As we no longer intended to return five of those rigs to service, but use their component parts as spare equipment inventory, we recorded the charge to write the rigs down to their fair market value and reduced the number of drilling rigs in our fleet by five. In 2003, no impairment of our long-lived assets was recorded as no change in circumstances or in our intentions indicated that the carrying value of the assets was not recoverable. We currently have 22 cold stacked and 15 inventory rigs.

Revenue Recognition. Revenue from daywork and footage contracts is recognized when earned as services are performed under the provisions of the contracts. Revenue from turnkey drilling contracts is recognized using the percentage-of-completion method based upon costs incurred to date compared to our estimate of the total contract costs. Under the percentage-of-completion, we make estimates of the total contract costs to be incurred, and to the extent these estimates change, the amount of revenue recognized could be affected. The significance of the accrued turnkey revenue varies from period to period depending on the overall level of demand for our services and the portion of that demand that is for turnkey services. At December 31, 2003, there were eight turnkey wells in progress versus four wells at December 31, 2002, with accrued revenue of $5.0 million and $3.6 million, respectively at such dates. Anticipated losses, if any, on uncompleted contracts are recorded at the time our estimated costs exceed the contract revenue.

Insurance Accruals. We maintain insurance coverage related to workers' compensation and general liability claims up to $1.0 million per occurrence with an aggregate of $2.0 million for general liability claims. These policies include deductibles of $350,000 per occurrence for workers' compensation coverage and $250,000 per occurrence for general liability coverage. If losses should exceed the workers' compensation and general liability policy amounts, we have excess liability coverage up to a maximum of $75.0 million. At December 31, 2003 and 2002, we had $9.4 million and $9.7 million, respectively, accrued for losses incurred within the deductible amounts for workers' compensation and general liability claims. The amount accrued for the provision for losses incurred varies depending on the number and nature of the claims outstanding at the balance sheet date. In addition, the accrual includes management's estimate of the future cost to settle each claim such as future changes in the severity of the claim and increases in medical costs. In addition, we are self-insured for our employee health plan but purchase stop-loss coverage in order to limit our exposure to a maximum of $175,000 per occurrence under the plan.

Income Taxes. Our deferred tax assets consist primarily of net operating loss carryforwards ("NOL's"). The estimated amount of our NOL's at December 31, 2003 are $133.5 million, which expires from 2010 to 2023. Approximately $7.2 million of these NOL's expire in 2010 and 2011, while the remaining $126.3 million expire between 2019 and 2023. Deferred tax assets must be assessed based upon the likelihood of recoverability from future taxable income and to the extent that recovery is not likely, a valuation allowance is established. At December 31, 2003, we do not have a valuation allowance as we believe that it is more likely than not that our future taxable income and reversal of deferred tax liabilities will be sufficient to recover our deferred tax assets. Our business, however, is extremely cyclical and is highly sensitive to changes in oil and natural gas prices and demand for our services and there can be no assurances that future economic or financial developments will not impact our ability to recover our deferred tax assets.

In addition, we have $26.5 million in permanent differences which relate to differences between the financial accounting and tax basis of acquired assets. The permanent difference will be reduced as the assets are depreciated for financial accounting purposes on a straight-line basis over the next nine years. As the amortization of these permanent differences is a fixed amount, our effective tax rate varies widely based upon the current level of income or loss. See Note 3 to our consolidated financial statements for a reconciliation of our statutory to effective tax rate.

Financial Condition and Liquidity

The following table summarizes our financial position as of December 31, 2003 and December 31, 2002.

	December 31, 2003		December 31, 2002	
	(In thousands)			
	Amount	%	Amount	%
Working capital	$ 68,727	14	$ 114,353	21
Property and equipment, net	404,278	85	420,791	78
Other noncurrent assets	5,141	1	4,668	1
Total	$ 478,146	100	$ 539,812	100
Long-term debt	$ 234,898	49	$ 249,613	46
Other long-term liabilities	47,611	10	64,941	12
Shareholders' equity	195,637	41	225,258	42
Total	$ 478,146	100	$ 539,812	100

Significant Changes in Financial Condition.

The significant changes in our financial position from December 31, 2002 to December 31, 2003 are a decrease in working capital of $45.6 million, a decrease in other long-term liabilities of $17.3 million and a decrease in shareholders' equity of $29.6 million. The decrease in working capital is a result of the issuance of the 3.75% Contingent Convertible Senior Notes due 2023 (the "3.75% Notes") and partial redemption of the 8⅞% Senior Notes due 2007 (the "8⅞% Notes"), the net loss for the period and capital expenditures. The decrease in shareholders' equity liabilities is due almost entirely to the net loss for the period of $30.2 million. The decrease in other long-term liabilities is due to the change in our net deferred tax liabilities resulting from a deferred tax benefit of $16.4 million.

On May 7, 2003, we issued $150.0 million aggregate principal amount of 3.75% Notes. The net proceeds of $146.6 million from the sale of the 3.75% Notes and $30.6 million of our available cash, a total of $177.2 million, were used to redeem $165.0 million aggregate principal amount of the 8⅞% Notes, plus accrued but unpaid interest. The partial redemption of the 8⅞% Notes was made on July 1, 2003 at a redemption premium of 102.9580%. This redemption premium of $4.9 million was included in interest expense in the second quarter of 2003. Amortization of the previously deferred financing costs associated with the notes was accelerated and approximately $2.5 million of additional interest expense was recognized in the quarter ended June 30, 2003.

After the partial redemption of the 8⅞% Notes, we continue to owe $85.0 million in aggregate principal amount of the 8⅞% Notes and $150.0 million in aggregate principal amount of the 3.75% Notes, for a total aggregate principal amount of $235.0 million for both classes of senior notes. Our annual interest expense will be reduced by approximately $9.5 million as a result of the refinancing, including approximately $9.0 million of cash savings.

The net effect on working capital of this refinancing was a reduction of $23.8 million consisting of a $15.0 million net reduction in debt outstanding, $4.9 million in a redemption premium paid on the 8⅞% Notes and $3.9 million in financing costs related to the issuance of the 3.75% Notes. Capital expenditures of $35.1 million during the year also contributed to the decrease in working capital. Capital expenditures included the cash purchase of two diesel electric SCR rigs for $9.0 million.

3.75% Notes

The 3.75% Notes bear interest at 3.75% per annum and mature on May 7, 2023. The 3.75% Notes are convertible into shares of our common stock, upon the occurrence of certain events, at a conversion price of $6.45 per share, which is equal to a conversion rate of approximately 155.0388 shares per $1,000 principal amount of 3.75% Notes, subject to adjustment. We will pay contingent interest at a rate equal to 0.5% per annum during any six-month period, with the initial six-month period commencing May 7, 2008, if the average trading price of the 3.75% Notes per $1,000 principal amount for the five day trading period ending on the third day immediately preceding the first day of the applicable six-month period equals $1,200 or more. The 3.75% Notes are our general unsecured senior obligations and are fully and unconditionally guaranteed, on a joint and several basis, by all of our domestic wholly-owned subsidiaries. Non-guarantor subsidiaries are immaterial. The 3.75% Notes and the guarantees rank equally with our 8⅞% Notes. Fees and expenses of approximately $3.9 million incurred at the time of issuance are being amortized through May 2013, the first date the holders may require us to repurchase the 3.75% Notes. We may redeem some or all of the 3.75% Notes at any time on or after May 14, 2008, payable in cash, plus accrued but unpaid interest, including contingent interest, if any, to the date of redemption at various redemption prices shown in Note 4 to our consolidated financial statements.

Holders may require us to repurchase all or a portion of their 3.75% Notes on May 7, 2013 or May 7, 2018, and upon a change of control, as defined in the indenture governing the 3.75% Notes, at 100% of the principal amount of the 3.75% Notes, plus accrued but unpaid interest, including contingent interest, if any, to the date of repurchase, payable in cash.

The 3.75% Notes are convertible, at the holders' option, prior to the maturity date into shares of our common stock in the following circumstances:

- during any calendar quarter, if the closing sale price per share of our common stock for at least 20 trading days in the period of 30 consecutive trading days ending on the last trading day of the calendar quarter preceding the quarter in which the conversion occurs, is more than 110% of the conversion price per share ($7.10 per share) on that 30th trading day;
- if we have called the 3.75% Notes for redemption;
- during any period that the credit ratings assigned to the 3.75% Notes by both Moody's Investors Service ("Moody's") and Standard & Poors ("S&P") Ratings Group are reduced below B1 and B+, respectively, or if neither rating agency is rating the 3.75% Notes;
- during the five trading day period immediately following any nine consecutive trading day period in which the average trading price per $1,000 principal amount of the 3.75% Notes for each day of such period was less than 95% of the product of the closing sale price per share of our common stock on that day multiplied by the number of shares of common stock issuable upon conversion of $1,000 principal amount of the 3.75% Notes; or
- upon the occurrence of specified corporate transactions, including a change of control.

The 3.75% Notes did not meet the criteria for conversion into common stock at any time during the year ended December 31, 2003 or during 2004 to the date of this Report. At February 10, 2004, the credit ratings assigned to the 3.75% Notes by Moody's and S&P were B1 and BB-, respectively.

The indenture governing the 3.75% Notes does not contain any restriction on the payment of dividends, the incurrence of indebtedness or the repurchase of our securities, and does not contain any financial covenants.

8⅞% Notes

At December 31, 2003, we had $85.0 million in aggregate principal amount of 8⅞% Notes outstanding. The 8⅞% Notes, issued in June 1997 and May 1998, bear interest at 8⅞% per annum with original maturities on July 1, 2007. The 8⅞% Notes are our general unsecured senior obligations and are fully and unconditionally guaranteed, on a joint and several basis, by all of our domestic wholly-owned subsidiaries. Non-guarantor subsidiaries are immaterial. The unamortized fees and expenses incurred at the time of issuance related to the principal amount outstanding are being amortized and discounts are being accreted over the life of the 8⅞% Notes.

We have the option to redeem the 8⅞% Notes in whole or in part during the twelve months beginning July 1, 2003 at 102.9580%, beginning July 1, 2004 at 101.4792% and beginning July 1, 2005 and thereafter at 100.0000% together with any accrued but unpaid interest to the redemption date. Upon a change of control as defined in the indentures governing the 8⅞% Notes, each holder of the 8⅞% Notes will have the right to require us to repurchase all or any part of such holder's 8⅞% Notes at a purchase price equal to 101% of the aggregate principal amount thereof, plus accrued but unpaid interest to the date of purchase. We may also, from time-to-time, seek to retire the 8⅞% Notes through redemptions, open market purchases and privately-negotiated transactions. Upon any such transaction, any difference between the redemption price and the face value of the 8⅞% Notes will be recorded as interest expense.

The indentures for the 8⅞% Notes permit us and our subsidiaries to incur additional indebtedness, including senior indebtedness of up to $100.0 million aggregate principal amount which may be secured by liens on all of our assets and the assets of our subsidiaries, subject to certain limitations. The indentures contain other covenants limiting our ability and our subsidiaries' ability to, among other things, pay dividends or make certain other restricted payments, make certain investments, incur additional indebtedness, permit liens, incur dividend and other payment restrictions affecting subsidiaries, enter into consolidation, merger, conveyance, lease or transfer transactions, make asset sales, enter into transactions with affiliates or engage in unrelated lines of business. These covenants are subject to certain exceptions and qualifications. The indentures consider non-compliance with the limitations events of default. In addition to non-payment of interest and principal amounts on the 8⅞% Notes, the indentures also consider default with respect to other indebtedness in excess of $10.0 million an event of default. In the event of a default, the principal and interest could be accelerated upon written notice by 25% or more of the holders of our 8⅞% Notes. We are in compliance with these covenants.

CIT Facility

Our subsidiary Grey Wolf Drilling Company L.P. has entered into a $75.0 million credit facility with the CIT Group/Business Credit, Inc. (the "CIT Facility") which expires during January 2006. The CIT Facility provides us with the ability to borrow up to the lesser of $75.0 million or 50% of the orderly liquidation value (as defined in the agreement) of certain drilling rig equipment located in the 48 contiguous states of the United States of America. The CIT Facility is a revolving facility with automatic renewals after expiration unless terminated by the lender on any subsequent anniversary date and then only upon 60 days prior notice. Periodic interest payments are due at a floating rate based upon our debt service coverage ratio within a range of either LIBOR plus 1.75% to 3.50% or prime plus 0.25% to 1.50%. The CIT Facility provides up to $20.0 million available for letters of credit. We are required to pay a commitment fee of 0.375% per annum on the unused portion of the CIT Facility and letters of credit accrue a fee of 1.25% per annum.

The CIT Facility contains affirmative and negative covenants and we are in compliance with these covenants. Substantially all of our assets, including our drilling equipment, are pledged as collateral under the CIT Facility which is also secured by a guarantee of Grey Wolf, Inc. and certain of our wholly-owned subsidiaries' guarantees. However, we retain the option, subject to a minimum appraisal value, under the CIT Facility to extract $75.0 million of the equipment out of the collateral pool in connection with the sale or exchange of such collateral or relocation of equipment outside the contiguous 48 states of the United States of America. We currently have no outstanding balance under the CIT Facility but had $16.4 million of undrawn letters of credit at February 10, 2004. These standby letters of credit are for the benefit of various insurance companies as collateral for premiums and retained losses which may become payable under the terms of the underlying insurance contracts and for other purposes. Outstanding letters of credit reduce the amount available for borrowing under the CIT facility.

Among the various covenants that we must satisfy under the CIT Facility are the following two covenants which apply whenever our liquidity, defined as the sum of cash, cash equivalents and availability under the CIT Facility, falls below $25.0 million:

- 1 to 1 EBITDA coverage of debt service, tested monthly on a trailing 12 month basis; and
- minimum tangible net worth (as defined in the CIT Facility) at the end of each quarter will be at least the prior year tangible net worth less $30.0 million adjusted for quarterly tests.

Additionally, if the total amount outstanding under the CIT Facility (including outstanding letters of credit) exceeds 50% of the orderly liquidation value of our domestic rigs, we are required to make a prepayment in the amount of the excess. Also, if the average rig utilization rate falls below 45% for two consecutive months, the lender will have the option to request one additional appraisal per year to aid in determining the current orderly liquidation value of the drilling equipment. Average rig utilization is defined as the total number of rigs owned which are operating under drilling contracts in the 48 contiguous states of the United States of America divided by the total number of rigs owned, excluding rigs not capable of working without substantial capital investment. Events of default under the CIT Facility include, in addition to non-payment of amounts due, misrepresentations and breach of loan covenants and certain other events including:

- default with respect to other indebtedness in excess of $350,000;
- judgments in excess of $350,000; or
- a change in control which means that we cease to own 100% of our two principal subsidiaries, some person or group has either acquired beneficial ownership of 30% or more of the outstanding common stock of Grey Wolf, Inc. or obtained the power to elect a majority of our board of directors, or our board of directors ceases to consist of a majority of "continuing directors" (as defined by the CIT Facility).

Certain Contractual Commitments

The following table summarizes certain of our contractual cash obligations and related payments due by period at December 31, 2003 (amounts in thousands):

	Payments Due by Period [1]				
Contractual Obligation	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
3.75% Notes [2]					
Principal	$ 150,000	$ –	$ –	$ –	$ 150,000
Interest	109,688	5,625	11,250	11,250	81,563
8⅞% Notes [2]					
Principal	85,000	–	–	85,000	–
Interest	30,176	7,544	15,088	7,544	–
Operating leases	944	674	257	13	–
Total contractual cash obligations	$ 375,808	$ 13,843	$ 26,595	$ 103,807	$ 231,563

(1) This assumes no conversion under, or acceleration of maturity dates due to redemption, breach of, or default under, the terms of the applicable contractual obligation.

(2) See "8⅞% Notes" and "3.75% Notes", above, for information relating to covenants, the breach of which could cause a default under, and acceleration of, the maturity date. Also see "3.75% Notes" for information related to the holders' conversion rights.

Our CIT Facility provides up to $20.0 million for the issuance of letters of credit. If letters of credit which we cause to be issued are drawn upon by the holders of those letters of credit, then we will become obligated to repay those amounts along with any accrued interest and fees. Letters of credit issued reduce the amount available for borrowing under the CIT Facility and, as a result, we had borrowing capacity of $58.6 million at December 31, 2003. The following table illustrates the undrawn outstanding standby letters of credit at December 31, 2003 and the potential maturities if drawn upon by the holders (amounts in thousands):

	Payments Due by Period [1]				
Potential Contractual Obligation	Total Committed	Less than 1 year	1-3 years	4-5 years	Over 5 years
Standby letters of credit	$ 16,445	$ –	$ 16,445	$ –	$ –
Total	$ 16,445	$ –	$ 16,445	$ –	$ –

(1) Assumes no acceleration of maturity date due to breach of, or default under, the potential contractual obligation.

Cash Flow

The net cash provided by or used in our operating, investing and financing activities is summarized below (amounts in thousands):

	Years Ended December 31,		
	2003	2002	2001
Net cash provided by (used in):			
Operating activities	$ (7,040)	$ 36,403	$ 148,312
Investing activities	(33,927)	(21,947)	(101,209)
Financing activities	(18,582)	(1,224)	491
Net increase (decrease) in cash:	$ (59,549)	$ 13,232	$ 47,594

Our cash flows from operating activities are affected by a number of factors including the number of rigs working under contract, whether the contracts are daywork, footage or turnkey, and the rate received for these services. Our cash flow generated from operating activities during the year ended December 31, 2003 was $4.1 million (before changes in operating assets and liabilities) compared to cash generated from operating activities during the year ended December 31, 2002 of $23.4 million (before changes in operating assets and liabilities). While the number of operating days increased by 10% from 2002 to 2003, our operating margin declined by $12.0 million. This decline was due in large part to the replacement of expiring term contracts with spot market contracts at lower rates and margins. The lower operating margin contributed to the reduction in cash flow from operating activities as did the $4.9 million in redemption premium paid upon partial redemption of the 8⅞% Notes. Our cash flows from operating activities were also impacted by changes in operating assets and liabilities which used $11.1 million and provided $13.0 million in cash flow for the years ended December 31, 2003 and 2002, respectively.

Generally, during times of increasing demand, our changes in working capital will result in the use of cash due primarily to the build-up of accounts receivable. While there was a small increase in overall demand in 2003 as compared to 2002, the $13.1 million increase in accounts receivable year over year was primarily due to the increase in demand for turnkey services. At the end of 2003, there were eight turnkey wells in progress while at the end of 2002 there where only four turnkey wells in progress. This is significant to our cash flow from operations in that we are generally responsible for significantly more costs while drilling under turnkey contracts (as opposed to daywork contracts) but we are not compensated until the contract terms have been completely satisfied. Under daywork contracts, we bill and are paid as work is performed.

Another significant change in working capital was the decrease in accrued interest of $6.5 million. This reduction in accrued interest is due to the partial redemption of the 8⅞% Notes and the sale of the 3.75% Notes which lowered our overall interest expense and changed the timing of our interest payments.

Our cash flow generated from operating activities during the year ended December 31, 2002 was $23.4 million (before changes in operating assets and liabilities) compared to cash generated in operating activities during the year ended December 31, 2001 of $150.6 million (before changes in operating assets and liabilities). This change is principally due to a 35% decrease in operating days and a 55% decrease in our per rig day operating margins between the two periods. Our cash flows from operating activities were also impacted by changes in operating assets and liabilities which provided $13.0 million and used $2.3 million in cash flow for the years ended December 31, 2002 and 2001, respectively. The cash provided by changes in operating assets and liabilities during 2002 was due to the decline in accounts receivable as a direct result of the decline in operating days and operating margins.

Cash flow used in investing activities for the years ended December 31, 2003, 2002, and 2001 primarily consisted of $35.1 million, 22.3 million, and $103.0 million of capital expenditures, respectively. These capital expenditures included the costs of sustaining our rigs, the acquisition of drill pipe and drill collars, the purchase of top drives, and other capital items. Also included in capital expenditures in 2003 was the cash purchase of two diesel electric SCR rigs for $9.0 million. In 2001, capital expenditures included approximately $55.5 million for the reactivation of cold-stacked and inventory rigs.

Cash flow used in financing activities for the year ended December 31, 2003 consisted of the partial redemption of the 8⅞% Notes and the sale of the 3.75% Notes, the net effect of which was a reduction in debt outstanding of $15.0 million.

Projected Cash Sources

We expect to use cash generated from operations to cover cash requirements, including debt service on the 3.75% Notes and 8⅞% Notes and capital expenditures in 2004. Capital expenditures for 2004 are projected to be between $27.0 million and $30.0 million, subject to the actual level of rig activity. We make semi-annual interest payments of $3.8 million on the 8⅞% Notes on January 1 and July 1 of each year and semi-annual interest payments of $2.8 million on the 3.75% Notes on May 7 and November 7 of each year through the dates of maturity. To the extent that we are unable to generate sufficient cash from operations we would be required to use cash on hand or draw on our CIT Facility. At February 10, 2004, our cash and cash equivalent balance was approximately $57.0 million.

From time to time we also review possible acquisition opportunities. While we currently have no agreements to acquire additional businesses or equipment, we may enter into such agreements in the future. Our ability to consummate any such transaction will be dependent in large part on our ability to fund, primarily through the capital markets, such a transaction. We cannot give assurance that adequate funding will be available on satisfactory terms.

Results of Operations

In accordance with Emerging Issues Task Force Issue No. 01-14 "Income Statement Characterization of Reimbursements Received for Out-of-Pocket Expenses Incurred," we have revised the presentation of reimbursements received for certain expenses in the periods presented. These reimbursements are now included in contract drilling revenues on our consolidated statement of operations rather than being recorded net of the incurred expenses in drilling operations expenses. This reclassification had no effect on net income or cash flows.

The following tables highlight rig days worked, contract drilling revenues and drilling operating expenses for our daywork and turnkey operations for the years ended December 31, 2003, 2002 and 2001.

	For the Year Ended December 31, 2003		
	Daywork Operations	Turnkey Operations (2)	Total
	(Dollars in thousands, except averages per rig day worked)		
Rig days worked	18,700	3,447	22,147
Contract drilling revenue	$ 178,818	$ 107,156	$ 285,974
Drilling operating expenses(1)	158,141	86,146	244,287
Operating margin	$ 20,677	$ 21,010	$ 41,687
Averages per rig day worked:			
Contract drilling revenue	$ 9,562	$ 31,087	$ 12,913
Drilling operating expenses	8,456	24,993	11,031
Operating margin	$ 1,106	$ 6,094	$ 1,882

	For the Year Ended December 31, 2002		
	Daywork Operations	Turnkey Operations (2)	Total
	(Dollars in thousands, except averages per rig day worked)		
Rig days worked	18,248	1,832	20,080
Contract drilling revenue	$ 197,594	$ 52,666	$ 250,260
Drilling operating expenses(1)	154,458	42,112	196,570
Operating margin	$ 43,136	$ 10,554	$ 53,690
Averages per rig day worked:			
Contract drilling revenue	$ 10,828	$ 28,748	$ 12,463
Drilling operating expenses	8,464	22,988	9,789
Operating margin	$ 2,364	$ 5,760	$ 2,674

	For the Year Ended December 31, 2001		
	Daywork Operations	Turnkey Operations (2)	Total
	(Dollars in thousands, except averages per rig day worked)		
Rig days worked	28,766	2,158	30,924
Contract drilling revenue	$ 376,222	$ 57,517	$ 433,739
Drilling operating expenses(1)	208,966	40,362	249,328
Operating margin	$ 167,256	$ 17,155	$ 184,411
Averages per rig day worked:			
Contract drilling revenue	$ 13,079	$ 26,657	$ 14,026
Drilling operating expenses	7,265	18,707	8,063
Operating margin	$ 5,814	$ 7,950	$ 5,963

(1) Drilling operating expenses exclude depreciation, and general and administrative expenses.
(2) Turnkey operations include the results from turnkey and footage contracts.

Comparison of Fiscal Years ended December 31, 2003 and 2002

Our operating margin decreased by $12.0 million, or 22%, to $41.7 million for the year ended December 31, 2003, from $53.7 million for the year ended December 31, 2002. Operating margin is defined as contract drilling revenues less drilling operating expenses. This decrease resulted from a $22.5 million decrease in operating margin from daywork operations, which was partially offset by a $10.5 million increase in operating margin from turnkey operations. On a per rig day basis, our total operating margin decreased by $792 per rig day, or 30%, to $1,882 in 2003 from $2,674 in 2002. This decrease included a $1,258 per rig day decrease from daywork operations and a $334 per rig day increase from turnkey operations.

Daywork Operations

The decrease in operating margin and operating margin per day discussed above was due primarily to the expiration at the end of 2002 and in 2003 of term contracts that were replaced with spot market contracts at lower rates. This decrease was partially offset by an increase of 452 rig days worked in 2003 compared to 2002. Contract drilling revenue and contract drilling revenue per rig day decreased as a result of these expiring term contracts. Total drilling operating expenses increased slightly due to the increase in the number of rig days worked; however, remained relatively constant on a per rig day basis.

Turnkey Operations

The increase in total turnkey operating margin was partially due to an increase of 1,615 days, or 88% in the number of rig days worked in 2003 compared to 2002. Total turnkey operating margin and operating margin per day also increased due to differences in the complexity of the wells drilled in 2003 compared to 2002. The increase in the number of turnkey operating days along with the difference in the complexity of the wells drilled, increased contract drilling revenue and drilling operating expenses by $54.5 million and $44.0 million, respectively. Contract drilling revenue and drilling operating expenses on a per rig day basis also increased because of the complexity differences.

Other

Depreciation expense increased by $3.9 million, or 8%, to $50.5 million for the year ended December 31, 2003 compared to $46.6 million for the year ended December 31, 2002. During the fourth quarter of 2002, we made the decision not to return five rigs to service and reclassified the component parts of these rigs to spare equipment, shortening the depreciable lives of this equipment. In addition, depreciation expense is higher due to capital expenditures during 2003.

General and administrative expenses increased by $666,000, or 6%, to $12.0 million for the year ended December 31, 2003 compared to $11.3 million for the year ended December 31, 2002. Items affecting general and administrative expenses include compensation expense in 2003 related to the hiring of our Executive Vice President and Chief Operating Officer as well as higher professional fees related to compliance with the Sarbanes-Oxley Act of 2002 and increases in insurance costs. These items increased expenses by approximately $1.2 million in 2003. In 2002, severance costs of $330,000 and non-cash compensation expense of $515,000 related to stock options were recorded as a result of the termination of employment of an executive officer.

Interest expense increased by $3.9 million, or 16%, to $27.8 million for 2003 from $23.9 million for 2002. Interest expense in 2003 includes approximately $8.5 million of costs associated with the partial redemption of our 8⅞% Notes on July 1, 2003 and interest on the $150.0 million aggregate principal amount of 3.75% Notes issued on May 7, 2003. These costs include a $4.9 million redemption premium for the 8⅞% Notes, $2.5 million in accelerated amortization of a pro-rata portion of the previously deferred financing costs on the 8⅞% Notes, and interest on the 3.75% Notes from May 7, 2003 to June 30, 2003. This additional interest expense was partially offset by $4.5 million lower interest for the last six months of 2003 due to the lower interest rate on the 3.75% Notes and $15.0 million reduction in principal amount of total debt outstanding.

Our income tax benefit increased by $9.2 million to $17.4 million in 2003 from $8.2 million in 2002. The increase is due to the level of losses and a change in our estimate of available state tax net operating losses in the fourth quarter of 2003. This change in estimate increased our income tax benefit by $938,000. Our income tax benefit is also affected by the annual amortization of $2.8 million in permanent differences related to differences between the financial accounting and tax basis of acquired assets. The permanent differences are amortized as these assets are depreciated for financial accounting purposes on a straight-line basis over their remaining useful lives of approximately nine years at December 31, 2003. As the annual amortization of these permanent differences is a fixed amount, our book effective tax rate can vary widely based upon the current level of income or loss.

Comparison of Fiscal Years ended December 31, 2002 and 2001

Our operating margin decreased by $130.7 million, or 71%, to $53.7 million for the year ended December 31, 2002, from $184.4 million for the year ended December 31, 2001. This decrease resulted from a $124.1 million decrease in operating margin from daywork operations and a $6.6 million decrease in operating margin from turnkey operations. On a per rig day basis, our total operating margin decreased by $3,289 per rig day, or 55%, to $2,674 in 2002 from $5,963 in 2001. This decrease included a $3,450 per rig day decrease from daywork operations and a $2,190 per rig day decrease from turnkey operations.

Daywork Operations

The decrease in operating margin and operating margin per rig day discussed above is due to numerous factors affecting contract drilling revenue and drilling operating expenses. First, there were 10,518 fewer rig days worked in 2002 compared to 2001, which resulted in lower revenues and expenses. Second, revenue and revenue per rig day decreased due to the expiration of term contracts that were replaced with spot market contracts at lower rates. Finally, drilling operating expenses per rig day increased due to a wage increase of 12% effective June 1, 2001, the retention of our experienced toolpushers and drillers during the downturn, the cost of cold-stacking rigs, and overhead and other fixed costs being spread over less rig days.

Turnkey Operations

The decrease in operating margin and operating margin per day discussed above was also due to several factors. The number of rig days worked decreased by 326 days, or 15%, in 2002 compared to 2001. This resulted in a decrease in contract drilling revenue, which was partially offset by an increase in the revenue per rig day. The increase in revenue per rig day and the increase in drilling operating expenses and drilling operating expenses per rig day resulted from differences in the complexity of the wells drilled between 2002 and 2001. Revenue and revenue per day were also affected by generally lower daywork dayrates in 2002 than in 2001. Lower daywork dayrates can affect the overall turnkey price charged to customers.

Other

Depreciation expense increased by $5.2 million, or 12%, to $46.6 million for the year ended December 31, 2002 compared to $41.4 million for the year ended December 31, 2001. The increase is primarily due to additional depreciation attributable to equipment purchased and placed into service during 2001 and 2002.

General and administrative expenses increased by $1.4 million, or 14%, to $11.3 million for the year ended December 31, 2002 compared to $9.9 million for the year ended December 31, 2001. This increase is due primarily to $330,000 for severance costs and $515,000 of non-cash compensation expense related to stock options as a result of the termination of employment of an officer in the first quarter of 2002. Also contributing to the increase are higher insurance costs and higher professional fees.

The difference in interest expense for the years ended December 31, 2002 and 2001 is negligible as the average outstanding debt balance was virtually the same and the largest component of our debt structure was our 8⅞% Notes that carry interest at a fixed rate.

Interest income decreased by $709,000, or 29%, to $1.7 million for the year ended December 31, 2002, from $2.4 million for the year ended December 31, 2001 due to lower interest rates in 2002 partially offset by higher cash balances. Cash balances were higher in 2002 as a result of an overall build in cash due to higher drilling activity and dayrates throughout 2001.

Net other income (expense) increased by $574,000 to income of $128,000 for the year ended December 31, 2002 from expense of $446,000 for the same period of 2001. The expense in 2001 related to the realization of $454,000 in previously unrealized foreign currency translation losses as a result of moving our Venezuela rigs to the United States.

We recorded an income tax benefit of $8.2 million in 2002 compared to income tax expense of $42.9 million in 2001. The change was due to losses incurred in 2002 and is also affected by the annual amortization of $2.8 million in permanent differences related to differences between the financial accounting and tax basis of acquired assets. The permanent difference are amortized as these assets are depreciated for financial accounting purposes on a straight-line basis over their remaining useful lives of approximately 10 years at December 31, 2002. As the annual amortization of these permanent differences is a fixed amount, our book effective tax rate varies widely based upon the current levels of income or loss.

Inflation and Changing Prices

Contract drilling revenues do not necessarily track the changes in general inflation as they tend to respond to the level of activity of the oil and gas industry in combination with the supply of equipment and the number of competing companies. Capital and operating costs are influenced to a larger extent by specific price changes in the oil and gas industry and to a lesser extent by changes in general inflation.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

Interest Rate Risk. We are subject to market risk exposure related to changes in interest rates on our CIT Facility. Interest on borrowings under the CIT facility accrues at a variable rate, using (at our election) either the prime rate plus 0.25% to 1.50% or LIBOR plus 1.75% to 3.5%, depending upon our debt service coverage ratio for the trailing 12 month period. We currently have no outstanding balance under the CIT facility and as such have no exposure at this time to a change in interest rates.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to
Consolidated Financial Statements
and Financial Statement Schedule

Schedules other than those listed above are omitted because they are either not applicable or not required or the information required is included in the consolidated financial statements or notes thereto.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of Directors
of Grey Wolf, Inc.:

We have audited the accompanying consolidated balance sheets of Grey Wolf, Inc. and Subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of operations, shareholders' equity and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2003. In connection with our audits of the consolidated financial statements, we have also audited the financial statement schedule for the years ended December 31, 2003, 2002 and 2001. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Grey Wolf, Inc. and Subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects the information set forth therein.

KPMG LLP

Houston, Texas
January 30, 2004

GREY WOLF, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(Amounts in thousands, except share data)

	December 31, 2003	December 31, 2002
ASSETS		
Current assets:		
Cash and cash equivalents	$ 54,350	$ 113,899
Restricted cash - insurance deposits	749	784
Accounts receivable, net of allowance of $2,443 and $2,500, respectively	60,181	47,034
Prepaids and other current assets	4,379	3,447
Total current assets	119,659	165,164
Property and equipment:		
Land, buildings and improvements	5,043	5,424
Drilling equipment	738,097	704,734
Furniture and fixtures	3,332	3,185
Total property and equipment	746,472	713,343
Less: accumulated depreciation	(342,194)	(292,552)
Net property and equipment	404,278	420,791
Other noncurrent assets	5,141	4,668
	$ 529,078	$ 590,623
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable - trade	$ 27,893	$ 19,460
Accrued workers' compensation	5,295	4,947
Payroll and related employee costs	6,660	6,685
Accrued interest payable	4,664	11,160
Other accrued liabilities	6,420	8,559
Total current liabilities	50,932	50,811
Senior notes	84,898	249,613
Contingent convertible notes	150,000	–
Other long-term liabilities	4,115	4,789
Deferred income taxes	43,496	60,152
Commitments and contingent liabilities	–	–
Shareholders' equity:		
Series B Junior Participating Preferred stock, $1 par value; 250,000 shares authorized, none outstanding	–	–
Common stock, $.10 par value; 300,000,000 shares authorized; 181,283,431 and 181,037,811 issued and outstanding, respectively	18,129	18,104
Additional paid-in capital	330,266	329,712
Accumulated deficit	(152,758)	(122,558)
Total shareholders' equity	195,637	225,258
	$ 529,078	$ 590,623

See accompanying notes to consolidated financial statements

GREY WOLF, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(Amounts in thousands, except per share data)

	Years Ended December 31,		
	2003	2002	2001
Revenues:			
Contract drilling	$ 285,974	$ 250,260	$ 433,739
Costs and expenses:			
Drilling operations	244,287	196,570	249,328
Depreciation	50,521	46,601	41,425
Provision for asset impairment	–	3,540	–
General and administrative	11,966	11,300	9,932
Total costs and expenses	306,774	258,011	300,685
Operating income (loss)	(20,800)	(7,751)	133,054
Other income (expense):			
Interest expense	(27,832)	(23,928)	(24,091)
Interest income	954	1,732	2,441
Gain on sale of assets	81	126	348
Other, net	14	128	(446)
Other expense, net	(26,783)	(21,942)	(21,748)
Income (loss) before income taxes	(47,583)	(29,693)	111,306
Income tax expense (benefit)			
Current	(938)	(1,871)	2,977
Deferred	(16,445)	(6,346)	39,876
Total income tax expense (benefit)	(17,383)	(8,217)	42,853
Net income (loss)	$ (30,200)	$ (21,476)	$ 68,453
Basic and diluted net income (loss) per common share	$ (0.17)	$ (0.12)	$ 0.38
Basic weighted average common shares outstanding	181,210	180,936	180,502
Diluted weighted average common shares outstanding	181,210	180,936	182,447

See accompanying notes to consolidated financial statements

GREY WOLF, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME
(Amounts in thousands)

	Series B Junior Participating Preferred Stock $1 par Value	Common Shares	Common Stock $.10 par Value	Additional Paid-in Capital	Deficit	Cumulative Comprehensive Income Adjustments	Total
Balance, December 31, 2000	–	179,881	$ 17,988	$ 325,417	$(169,535)	$ (454)	$ 173,416
Exercise of stock options	–	845	85	1,597	–	–	1,682
Tax benefit of stock option exercises	–	–	–	1,292	–	–	1,292
Cumulative foreign translation losses	–	–	–	–	–	454	454
Net income	–	–	–	–	68,453	–	68,453
Comprehensive net income	–	–	–	–	68,453	454	68,907
Balance, December 31, 2001	–	180,726	18,073	328,306	(101,082)	–	245,297
Exercise of stock options	–	312	31	655	–	–	686
Non-cash compensation expense	–	–	–	542	–	–	542
Tax benefit of stock option exercises	–	–	–	209	–	–	209
Comprehensive net loss	–	–	–	–	(21,476)	–	(21,476)
Balance, December 31, 2002	–	181,038	18,104	329,712	(122,558)	–	225,258
Exercise of stock options	–	245	25	343	–	–	368
Tax benefit of stock option exercises	–	–	–	211	–	–	211
Comprehensive net loss	–	–	–	–	(30,200)	–	(30,200)
Balance, December 31, 2003	–	181,283	$ 18,129	$ 330,266	$(152,758)	$ –	$ 195,637

See accompanying notes to consolidated financial statements

GREY WOLF, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in thousands)

	Years Ended December 31,		
	2003	2002	2001
Cash flows from operating activities:			
Net income (loss)	$ (30,200)	$ (21,476)	$ 68,453
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation	50,521	46,601	41,425
Provision for asset impairment	–	3,540	–
Non-cash compensation expense	–	542	–
Provision for doubtful accounts	–	700	695
Gain on sale of assets	(81)	(126)	(348)
Foreign exchange (gain) loss	(14)	(128)	446
Deferred income taxes	(16,656)	(6,555)	38,584
Accretion of debt discount	285	86	86
Tax benefit of stock options exercises	211	209	1,292
(Increase) decrease in restricted cash	35	100	(25)
(Increase) decrease in accounts receivable	(13,147)	19,840	(6,540)
(Increase) decrease in other current assets	(961)	(1,691)	1,248
Increase (decrease) in accounts payable trade	8,476	(1,590)	(4,586)
Increase (decrease) in accrued workers' compensation	348	352	(210)
Increase (decrease) in other current liabilities	(8,660)	(4,997)	3,888
Increase in other	2,803	996	3,904
Cash provided by (used in) operating activities	(7,040)	36,403	148,312
Cash flows from investing activities:			
Property and equipment additions	(35,102)	(22,335)	(103,036)
Proceeds from sales of equipment	1,175	388	1,827
Cash used in investing activities	(33,927)	(21,947)	(101,209)
Cash flows from financing activities:			
Proceeds from long-term debt	146,625	–	–
Repayments of long-term debt	(165,000)	(1,910)	(911)
Financing costs	(575)	–	(280)
Proceeds from exercise of stock options	368	686	1,682
Cash provided by (used in) financing activities	(18,582)	(1,224)	491
Net increase (decrease) in cash and cash equivalents	(59,549)	13,232	47,594
Cash and cash equivalents, beginning of year	113,899	100,667	53,073
Cash and cash equivalents, end of year	$ 54,350	$ 113,899	$ 100,667
Supplemental Cash Flow Disclosure			
Cash paid for interest:	$ 30,510	$ 22,817	$ 22,750
Cash paid for (refund of) taxes:	$ (879)	$ (1,822)	$ 3,019

See accompanying notes to consolidated financial statements

(1) Summary of Significant Accounting Policies

Nature of Operations. Grey Wolf, Inc. is a Texas corporation formed in 1980. Grey Wolf, Inc. is a holding company with no independent assets or operations but through its subsidiaries is engaged in the business of providing onshore contract drilling services to the oil and gas industry. Grey Wolf, Inc., through its subsidiaries, currently conducts operations in Alabama, Arkansas, Louisiana, Mississippi, New Mexico, Texas and Wyoming. The consolidated financial statements include the accounts of Grey Wolf, Inc. and its majority-owned subsidiaries (the "Company" or "Grey Wolf"). All significant intercompany accounts and transactions are eliminated in consolidation.

Property and Equipment. Property and equipment are stated at cost. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets, between three and fifteen years.

Impairment of Long-Lived Assets and Long-Lived Assets to Be Disposed Of. The Company reviews its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Impairment of assets to be held and used is determined by a comparison of the carrying amount of an asset to undiscounted future net cash flows expected to be generated by an asset. If such assets are considered to be impaired, the impairment to be recognized is measured by an amount by which the carrying amount of the assets exceeds the fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or fair value less costs to sell. During the fourth quarter of 2002, we recorded a pretax non-cash asset impairment charge of $3.5 million (see Note 12).

Revenue Recognition. Revenue from daywork and footage contracts is recognized when earned as services are performed under the provisions of the contract. Revenue from turnkey drilling contracts is recognized as earned using the percentage-of-completion method based upon costs incurred to date and estimated total contract costs. Provision is made currently for anticipated losses, if any, on uncompleted contracts.

Earnings per Share. Basic earnings per share is based on the weighted average shares outstanding, during the applicable period, without any dilutive effects considered. Diluted earnings per share reflects dilution from all outstanding options and shares issuable upon the conversion of the 3.75% Contingent Convertible Senior Notes once a contingency has been met. The following is a reconciliation of basic and diluted weighted average common shares outstanding (in thousands):

	2003	2002	2001
Weighted average common shares outstanding - basic	181,210	180,936	180,502
Effect of dilutive securities: Options - Treasury Stock Method	–	–	1,945
Weighted average common shares outstanding - diluted	181,210	180,936	182,447

In 2003, the Company has excluded approximately 23.3 million shares issuable upon conversion of the 3.75% Contingent Convertible Senior Notes as none of the contingencies have been met (see Note 4). The Company incurred net losses for the years ended December 31, 2003 and 2002 and has, therefore, excluded certain securities from the computation of diluted earnings per share as the effect would be anti-dilutive. Securities excluded from the computation of diluted earnings per share for the years ended December 31, 2003 and 2002 were options to purchase 10.2 million shares and 8.7 million shares, respectively. Options to purchase 4.1 million shares for the three months ended December 31, 2001 and September 30, 2001 and 998,500 shares for the three months ended June 30, 2001 and March 31, 2001 were not included in the computation of diluted EPS because the options' exercise price was greater than the average market price of the common shares.

Income Taxes. The Company records deferred tax liabilities utilizing an asset and liability approach. This method gives consideration to the future tax consequences associated with differences between the financial accounting and tax basis of assets and liabilities. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. The Company and its domestic subsidiaries file a consolidated federal income tax return.

Stock-Based Compensation. In December 2002, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standard ("SFAS") No. 148, "Accounting for Stock-Based Compensation-Transition and Disclosure," which amends SFAS No. 123, "Accounting for Stock-Based Compensation," by providing alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the provisions of SFAS No. 123 to require more prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results of operations. The Company has adopted the more prominent disclosures required by SFAS No. 148 as of March 31, 2003; however, as permitted under SFAS No. 123, the Company continues to apply Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations in accounting for its stock option plans. These plans are more fully described in Note 5.

Accordingly, no compensation expense has been recognized for stock option grants as all options granted had an exercise price equal to the market value of the underlying common stock on the date of grant. Had compensation expense for the stock option grants been determined on the fair value at the grant dates consistent with the method of SFAS No. 123, the Company's net loss and loss per share would have been adjusted to the pro forma amounts indicated below (amounts in thousands, except per share amounts):

	2003	2002	2001
Net income (loss), as reported	$ (30,200)	$ (21,476)	$ 68,453
Add: Stock-based employee compensation expense included in reporting net loss, net of related tax effects	–	407	–
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(2,523)	(2,249)	(1,562)
Pro forma net income (loss)	$ (32,723)	$ (23,318)	$ 66,891
Income (loss) per share - basic and diluted			
As reported	$ (0.17)	$ (0.12)	$ 0.38
Pro forma	$ (0.18)	$ (0.13)	$ 0.37

For purposes of determining compensation costs using the provisions of SFAS No. 123, the fair value of option grants was determined using the Black-Scholes option-valuation model. The weighted average fair value per share of stock options granted was $2.36 in 2003, $1.80 in 2002 and $3.90 in 2001. The key input variables used in valuing the options granted in 2003, 2002 and 2001 were: risk-free interest rate based on five-year Treasury strips of 2.89% to 3.35% in 2003, 2.62% in 2002, and 4.60% in 2001; dividend yield of zero in each year; stock price volatility of 66% to 71% for 2003 and 75% for both 2002 and 2001; and expected option lives of five years for each year presented.

Fair Value of Financial Instruments. The carrying amount of the Company's cash and short-term investments approximates fair value because of the short maturity of those instruments. The carrying amount of the Company's credit facility approximates fair value as the interest is indexed to the prime rate or LIBOR. The fair value of the 8⅞% Senior Notes at December 31, 2003 and 2002 was $87.6 million and $252.5 million, respectively, compared to the face value of $85.0 million and $250.0 million, respectively. The fair value of the 3.75%

Contingent Convertible Senior Notes was $141.2 million at December 31, 2003 versus a face value of $150.0 million. Fair value was estimated based on quoted market prices.

Cash Flow Information. Cash flow statements are prepared using the indirect method. The Company considers all unrestricted highly liquid investments with a maturity of three months or less at the time of purchase to be cash equivalents.

Restricted Cash. Restricted cash consists of investments in interest bearing certificates of deposit which are used as collateral for letters of credit securing insurance deposits and other purposes. The carrying value of the investments approximates the current market value.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires the use of certain estimates and assumptions relating to the reporting of assets and liabilities and the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

Concentrations of Credit Risk. Substantially all of the Company's contract drilling activities are conducted with major and independent oil and gas companies in the United States. Historically, the Company has not required collateral or other security for the related receivables from such customers. However, the Company has required certain customers to deposit funds in escrow prior to the commencement of drilling. Actions typically taken by the Company in the event of nonpayment include filing a lien on the customer's producing properties and filing suit against the customer.

Comprehensive Income. Comprehensive income includes all changes in a company's equity during the period that result from transactions and other economic events, other than transactions with its shareholders.

Recent Accounting Pronouncements. In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations," which addressed financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. This statement applies to all entities that have legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development or normal use of the asset. SFAS 143 is effective for fiscal years beginning after June 15, 2002. The Company adopted SFAS No. 143 on January 1, 2003. The adoption of SFAS No. 143 did not have an effect on the Company's financial condition or results of operations for the year ended December 31, 2003.

In April, 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment to FASB Statement No. 13, and Technical Corrections." Under the provisions of this statement, gains and losses from extinguishment of debt generally will no longer be classified as extraordinary items. In addition, this statement eliminates an inconsistency between the required accounting for sale-leaseback transactions and the required accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. This statement also makes various technical corrections, clarifies meanings, or describes their applicability under changed conditions. The Company adopted SFAS No. 145 on January 1, 2003. The adoption of SFAS No. 145 did not have a material effect on the Company's financial position or results of operations for the year ended December 31, 2003.

In July 2002, the FASB issued SFAS No. 146, "Accounting for Cost Associated with Exit or Disposal Activities." SFAS No. 146 is effective for exit or disposal activities that are initiated after December 31, 2002. The Statement addresses financial accounting and reporting for costs associated with exit or disposal activities and requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. SFAS No. 146 nullifies Emerging Issues Task Force 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)." The adoption of SFAS No. 146 did not have an effect on the Company's financial position or results of operations for the year ended December 31, 2003.

The FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," in April 2003. SFAS No. 149 amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 149 is effective for existing contracts and new contracts entered into after June 30, 2003. The provisions of SFAS No. 149 did not have a material impact on the Company's consolidated financial statements for the year ended December 31, 2003.

The FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity," in May 2003. SFAS No. 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. SFAS No. 150 is effective for financial instruments entered into or modified after May 31, 2003 and is otherwise effective at the beginning of the first interim period beginning after June 15, 2003. The provisions of SFAS No. 150 did not have a material impact on the Company's consolidated financial statements for the year ended December 31, 2003.

The FASB issued Interpretation ("FIN") No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," in November 2002. FIN No. 45 is applicable on a prospective basis for initial recognition and measurement provisions to guarantees issued after December 2002. FIN No. 45 requires a guarantor to recognize, at the inception of a guarantee, a liability for the fair value of the obligations undertaken in issuing the guarantee and expands the required disclosures to be made by the guarantor about its obligation under certain guarantees that it has issued. The adoption of FIN No. 45 did not have a material impact on the Company's financial position or results of operations for the year ended December 31, 2003.

Reclassification. In accordance with Emerging Issues Task Force Issue No. 01-14 "Income Statement Characterization of Reimbursements Received for Out-of-Pocket Expenses Incurred," the Company has revised the presentation of reimbursements received for certain expenses in the periods presented. These reimbursements are now included in contract drilling revenues on the income statement versus previously being recorded net of the incurred expenses in drilling operations expenses. This reclassification had no effect on net income or cash flows. In addition, certain other amounts in 2001 and 2002 have been reclassified to conform to the presentation in 2003.

(2) Significant Property Transactions

On June 4, 2003, the Company purchased two working rigs for an aggregate of $9.0 million in cash. One of the rigs purchased is a 1,200 horsepower diesel electric SCR rig capable of drilling to 17,000 feet and the other is a 1,000 horsepower diesel electric SCR rig capable of drilling to 15,000 feet.

During the second quarter of 2001, the Company moved its five Venezuela rigs to the United States and in the third quarter of 2001 sold three of the five rigs for an aggregate of $1.3 million. This sale resulted in a gain of approximately $602,000. As a result of moving its Venezuela rigs to the United States, the Company realized $454,000 of previously unrealized foreign currency translation losses during the second quarter of 2001.

(3) Income Taxes

The Company and its U.S. subsidiaries file consolidated federal income tax returns. The components of the provision for income taxes consisted of the following (amounts in thousands):

	For the Years Ended December 31,		
	2003	2002	2001
Current			
Federal	$ –	$ (1,871)	$ 1,870
State	(938)	–	1,107
	$ (938)	$ (1,871)	$ 2,977
Deferred			
Federal	$ (14,958)	$ (7,080)	$ 38,557
State	(1,487)	734	1,319
	$ (16,445)	$ (6,346)	$ 39,876

Deferred income taxes are determined based upon the difference between the carrying amount of assets and liabilities for financial reporting purposes and amounts used for income tax purposes, and net operating loss and tax credit carryforwards. The tax effects of the Company's temporary differences and carryforwards are as follows (amounts in thousands):

	December 31,	
	2003	2002
Deferred tax assets		
Net operating loss carryforwards	$ 47,964	$ 27,008
Tax credit carryforwards	14	14
Workers compensation accruals	3,501	3,622
Other	1,411	1,229
	52,890	31,873
Deferred tax liabilities		
Depreciation	96,386	92,025
Net deferred tax liability	$ 43,496	$ 60,152

At December 31, 2003 and 2002, the Company had U.S. net operating loss ("NOL") carryforwards of $154.5 million and $98.2 million, respectively, which expire at various times from 2010 through 2023. The NOL carryforwards are subject to annual limitations as a result of the changes in ownership of the Company in 1989, 1994 and 1996. Management believes it is more likely than not that future earnings and reversal of deferred tax liabilities will be sufficient to permit the Company to realize its deferred tax assets.

For financial reporting purposes, approximately $21.0 million of the NOL carryforwards was utilized to offset the book versus tax basis differential in the recording of the assets acquired in transactions prior to 1999.

The following summarizes the differences between the federal statutory tax rate of 35% (amounts in thousands):

	For the Years Ended December 31,		
	2003	2002	2001
Income tax expense (benefit) at statutory rate	$ (16,654)	$ (10,393)	$ 38,957
Increase (decrease) in taxes resulting from:			
Permanent differences, primarily due to basis differences in acquired assets	1,208	1,707	1,320
Foreign (income) loss	17	(12)	95
State taxes, net	(1,576)	477	1,576
Other	(378)	4	905
Income tax expense (benefit)	$ (17,383)	$ (8,217)	$ 42,853

(4) Long-Term Debt

Long-term debt consists of the following (amounts in thousands):

	December 31,	
	2003	2002
Senior notes due July 2007, general unsecured senior obligations guaranteed by the Company's domestic subsidiaries, bearing interest at 8⅞% per annum payable semi-annually	$ 84,898	$ 249,613
Contingent convertible senior notes due May 2023, general unsecured senior obligations guaranteed by the Company's domestic subsidiaries, bearing interest at 3.75% per annum payable semi-annually	150,000	–
	234,898	249,613
Less current maturities	–	–
Long-term debt	$ 234,898	$ 249,613

3.75% Contingent Convertible Senior Notes due May 2023.

On May 7, 2003, the Company issued $150.0 million aggregate principal amount of 3.75% Contingent Convertible Senior Notes due 2023 (the "3.75% Notes") in a private offering that yielded net proceeds of $146.6 million. The 3.75% Notes bear interest at 3.75% per annum and mature on May 7, 2023. The 3.75% Notes are convertible, upon the occurrence of certain events, at a conversion price of $6.45 per share, which is equal to a conversion rate of approximately 155.0388 shares per $1,000 principal amount of the 3.75% Notes, subject to adjustment. The Company will pay contingent interest at a rate equal to 0.50% per annum during any six-month period, with the initial six-month period commencing May 7, 2008, if the average trading price of the 3.75% Notes per $1,000 principal amount for the five day trading period ending on the third day immediately preceding the first day of the applicable six-month period equals $1,200 or more. The 3.75% Notes are general unsecured senior obligations of the Company and are fully and unconditionally guaranteed, on a joint and several basis, by all domestic wholly-owned subsidiaries of the Company. Non-guarantor subsidiaries are immaterial. The 3.75% Notes and the guarantees rank equally with the Company's 8⅞% Notes due July 2007 (the "8⅞% Notes"). Fees and expenses of $3.9 million incurred at the time of issuance are being amortized through May 2013, the first date the holders may require the Company to repurchase the 3.75% Notes.

The Company may redeem some or all of the 3.75% Notes at any time on or after May 14, 2008, at a redemption price shown below, payable in cash, plus accrued but unpaid interest, including contingent interest, if any, to the date of redemption:

Period	Redemption Price
May 14, 2008 through May 6, 2009	101.88%
May 7, 2009 through May 6, 2010	101.50%
May 7, 2010 through May 6, 2011	101.13%
May 7, 2011 through May 6, 2012	100.75%
May 7, 2012 through May 6, 2013	100.38%
May 7, 2013 and thereafter	100.00%

Holders may require the Company to repurchase all or a portion of the 3.75% Notes on May 7, 2013 or May 7, 2018, and upon a change of control, as defined in the indenture governing the 3.75% Notes, at 100% of the principal amount of the 3.75% Notes, plus accrued but unpaid interest, including contingent interest, if any, to the date of repurchase, payable in cash.

The 3.75% Notes are convertible, at the holders' option, prior to the maturity date into shares of our common stock under the following circumstances:

- during any calendar quarter, if the closing sale price per share of our common stock for at least 20 trading days in the period of 30 consecutive trading days ending on the last trading day of the calendar quarter preceding the quarter in which the conversion occurs, is more than 110% of the conversion price per share ($7.10 per share) on that 30th trading day;
- if the Company has called the 3.75% Notes for redemption;
- during any period that the credit ratings assigned to the 3.75% Notes by both Moody's Investors Service and Standard & Poor's Ratings Group are reduced below B1 and B+, respectively, or if neither rating agency is rating the 3.75% Notes;
- during the five trading day period immediately following any nine consecutive trading day period in which the average trading price per $1,000 principal amount of the 3.75% Notes for each day of such period was less than 95% of the product of the closing sale price per share of the Company's common stock on that day multiplied by the number of shares of common stock issuable upon conversion of $1,000 principal amount of the 3.75% Notes; or upon the occurrence of specified corporate transactions, including a change of control.

The 3.75% Notes did not meet the criteria for conversion into common stock at any time during the year ended December 31, 2003. At February 10, 2004, the credit ratings assigned to the 3.75% Notes by Moody's Investor Service and Standard & Poor's Ratings Group were B1 and BB-, respectively.

8⅞% Notes due July 2007.

At December 31, 2003, the Company had $85.0 million in principal amount of 8⅞% Notes outstanding. The 8⅞% Notes bear interest at 8⅞% per annum and mature on July 1, 2007. The 8⅞% Notes are general unsecured senior obligations of the Company and are fully and unconditionally guaranteed, on a joint and several basis, by all domestic wholly-owned subsidiaries of the Company. Non-guarantor subsidiaries are immaterial.

On July 1, 2003, the $146.6 million of net proceeds from the issuance of the 3.75% Notes plus $30.6 million of available cash were used to redeem $165.0 million aggregate principal amount of 8⅞% Notes previously outstanding at 102.9580%, plus accrued interest. The redemption premium of $4.9 million was included in interest expense in the second quarter of 2003. Amortization of the previously deferred financing costs associated with the partial redemption of the 8⅞% Notes on July 1, 2003 was accelerated and approximately $2.5 million in additional interest expense was recognized in the quarter ended June 30, 2003. All other fees and expenses incurred at the time of issuance are being amortized and discounts are being accreted over the life of the 8⅞% Notes.

The Company has the option to redeem the 8⅞% Notes in whole or in part during the twelve month periods beginning July 1, 2003 at 102.9580%, beginning July 1, 2004 at 101.4792% and beginning July 1, 2005 and thereafter at 100.0000%, together with any interest accrued and unpaid to the redemption date. Upon a change of control as defined in the indentures, each holder of the 8⅞% Notes will have the right to require the Company to repurchase all or any part of such holder's 8⅞% Notes at a purchase price equal to 101% of the aggregate principal amount thereof, plus accrued and unpaid interest to the date of purchase. We may also, from time to time, seek to retire the 8⅞% Notes through redemption, open market purchases and privately negotiated transactions. Any difference between the redemption price and the face value of the 8⅞% Notes will be recorded as interest expense.

The indentures for the 8⅞% Notes permit us and our subsidiaries to incur additional indebtedness, including senior indebtedness of up to $100.0 million aggregate principal amount which may be secured by liens on all of our assets and the assets of our subsidiaries, subject to certain limitations. The indentures contain other covenants limiting our ability and our subsidiaries' ability to, among other things, pay dividends or make certain other restricted payments, make certain investments, incur additional indebtedness, permit liens, incur dividend and other payment restrictions affecting subsidiaries, enter into consolidation, merger, conveyance, lease or transfer transactions, make asset sales, enter into transactions with affiliates or engage in unrelated lines of business. These covenants are subject to certain exceptions and qualifications. The indentures consider non-compliance with the limitations events of default. In addition to non-payment of interest and principal amounts on the 8⅞% Notes, the indentures also consider default with respect to other indebtedness in excess of $10.0 million an event of default. In the event of a default, the principal and interest could be accelerated upon written notice by 25% or more of the holders of our 8⅞% Notes. As of December 31, 2003 we are in compliance with these covenants.

CIT Facility. The Company's subsidiary Grey Wolf Drilling Company L.P. has a $75.0 million credit facility with the CIT Group/Business Credit, Inc. (the "CIT Facility") which expires during January 2006. The CIT Facility provides the Company with the ability to borrow up to the lesser of $75.0 million or 50% of the orderly liquidation value (as defined in the agreement) of certain drilling rig equipment located in the 48 contiguous states of the United States of America. The CIT Facility is a revolving facility with automatic renewals after expiration unless terminated by the lender on any subsequent anniversary date and then only upon 60 days prior notice. Periodic interest payments are due at a floating rate based upon the Company's debt service coverage ratio within a range of either LIBOR plus 1.75% to 3.50% or prime plus 0.25% to 1.50%. The CIT Facility provides up to $20.0 million available for letters of credit. The Company is required to pay a commitment fee of 0.375% per annum on the unused portion of the CIT Facility and letters of credit accrue a fee of 1.25% per annum.

The CIT Facility contains affirmative and negative covenants and the Company is in compliance with these covenants. Substantially all of the Company's assets, including its drilling equipment, are pledged as collateral under the CIT Facility which is also secured by a guarantee of Grey Wolf, Inc. and certain of the Company's wholly-owned subsidiaries guarantees. The Company, however, retains the option, subject to a minimum appraisal value, under the CIT Facility to extract $75.0 million of the equipment out of the collateral pool in connection with the sale or exchange of such collateral or relocation of equipment outside the contiguous 48 states of the United States of America.

Among the various covenants that we must satisfy under the CIT Facility are the following two covenants which apply whenever our liquidity, defined as the sum of cash, cash equivalents and availability under the CIT Facility, falls below $25.0 million.

- 1 to 1 EBITDA coverage of debt service, tested monthly on a trailing 12 month basis; and
- minimum tangible net worth (all as defined in the CIT Facility) at the end of each quarter will be at least the prior year tangible net worth less $30.0 million adjusted for quarterly tests.

Additionally, if the total amount outstanding under the CIT Facility (including outstanding letters of credit) exceeds 50% of the orderly liquidation value of our domestic rigs, we are required to make a prepayment in the amount of the excess. Also, if the average rig utilization rate falls below 45% for two consecutive months, the lender will have the option to request one additional appraisal per year to aid in determining the current orderly liquidation value of the drilling equipment. Average rig utilization is defined as the total number of rigs owned which are operating under drilling contracts in the 48 contiguous states of the United States of America divided by the total number of rigs owned, excluding rigs not capable of working without substantial capital investment. Events of default under the CIT Facility include, in addition to non-payment of amounts due, misrepresentations and breach of loan covenants and certain other events including:

- default with respect to other indebtedness in excess of $350,000;
- judgments in excess of $350,000; or
- a change in control which means that we cease to own 100% of our two principal subsidiaries, some person or group has either acquired beneficial ownership of 30% or more of the Company or obtained the power to elect a majority of our board of directors, or our board of directors ceases to consist of a majority of "continuing directors" (as defined by the CIT Facility).

The Company currently has no outstanding balance under the CIT Facility and had $16.4 million of undrawn standby letters of credit at December 31, 2003. These standby letters of credit are for the benefit of various insurance companies as collateral for premiums and retained losses which may become payable under the terms of the underlying insurance contracts and for other purposes. Outstanding letters of credit reduce the amount available for borrowing under the CIT facility.

The Company had non-cash activities for the years ended December 31, 2002 and 2001 related to vehicle additions under capital leases. The non-cash amounts excluded from cash used in investing activities and cash provided by financing activities were $199,000 and $1.7 million for the years ended December 31, 2002 and 2001, respectively.

(5) Capital Stock and Stock Option Plans

On September 21, 1998, the Company adopted a Shareholder Rights Plan (the "Plan") in which rights to purchase shares of Junior Preferred stock will be distributed as a dividend at the rate of one Right for each share of common stock.

Each Right will entitle holders of the Company's common stock to buy one-one thousandth of a share of Grey Wolf's Series B Junior Participating Preferred stock at an exercise price of $11. The Rights will be exercisable only if a person or group acquires beneficial ownership of 15% or more of Grey Wolf's common stock or announces a tender or exchange offer upon consummation of which such person or group would beneficially own 15% or more of Grey Wolf's common stock. Furthermore, if any person becomes the beneficial owner of 15% or more of Grey Wolf's common stock, each Right not owned by such person or related parties will enable its holder to purchase, at the Right's then-current exercise price, shares of common stock of the Company having a value of twice the Right's exercise price. The Company will generally be entitled to redeem the Rights at $.001 per Right at any time until the 10th day following public announcement that a 15% position has been acquired.

The 2003 Incentive Plan (the "2003 Plan") was approved by shareholders in May 2003. The 2003 Plan authorizes the grant of the following equity-based awards:

- incentive stock options;
- non-statutory stock options;
- restricted shares; and
- other stock-based and cash awards.

The 2003 Plan replaced the Company's 1996 Employee Stock Option Plan (the "1996 Plan"); provided, however that outstanding options previously granted shall continue to be exercisable subject to the terms and conditions of such grants. The 1996 Plan allowed for grants of non-statutory options to purchase common stock, but no further grants of common stock will be made under the 1996 Plan. The 2003 Plan reserves a maximum of 17.0 million shares of the Company's common stock underlying all equity-based awards, but is reduced by the shares of common stock subject to previous grants under the 1996 Plan. At December 31, 2003, there were 6.5 million shares of common stock available for grant under the 2003 Plan until March 2013. Prior to 2003, the Company also granted options under stock option agreements with its chief executive officer and directors that are outside of the 2003 Plan. At December 31, 2003, these individuals had options outstanding to purchase an aggregate of 2.0 million shares of common stock.

The exercise price of stock options approximates the fair market value of the stock at the time the option is granted. A portion of the outstanding options became exercisable upon issuance and the remaining become exercisable in varying increments over three to five-year periods. The options expire on the tenth anniversary of the date of grant.

On November 13, 2001, the Company amended all outstanding stock option agreements issued under the 1996 Employee Stock Option Plan and certain outstanding stock option agreements issued to executive officers and directors. Based upon the occurrence of certain events ("triggering events"), the amendments provide for accelerated vesting of options and the extension of the period in which a current employee option holder has to exercise his options. The provisions of the amendments provide for accelerated vesting of options after termination of employment of a current option holder within one year of a change of control of the Company (as defined in the amendment). Triggering events that cause an extension of the exercise period, but not longer than the remaining original exercise period, include termination of employment as a result of any reason not defined as termination for cause, voluntary resignation, or retirement in the amendment.

In accordance with Accounting Principles Board Opinion 25 ("APB 25"), the amendments to the stock option agreements created a new measurement date of November 13, 2001. APB 25 requires the Company to determine the intrinsic value of the options at the measurement date and recognize non-cash compensation expense upon the occurrence of a triggering event. The amount of compensation expense that would be recognized upon the occurrence of a triggering event is the difference between the fair market value of the Company's stock on the measurement date and the original exercise prices of the options.

In March 2002, a triggering event occurred when an officer's employment terminated. As a result, the Company recognized approximately $515,000 of non-cash compensation expense along with approximately $330,000 of severance cost. In addition, the Company recognized approximately $27,000 of non-cash compensation expense during the remainder of 2002. These amounts have been included in general and administrative expenses on the consolidated statement of operations.

Stock option activity for all stock options issued as of December 31, 2003, 2002 and 2001 was as follows (number of shares in thousands):

	2003		2002		2001	
	No. of Shares	Weighted Average Exercise Price	No. of Shares	Weighted Average Exercise Price	No. of Shares	Weighted Average Exercise Price
Outstanding – beginning of the year	8,721	$ 2.85	7,512	$ 2.85	7,318	$ 2.25
Granted	2,161	3.91	2,302	2.88	1,149	6.08
Exercised	(246)	1.50	(312)	2.20	(846)	1.99
Cancelled	(427)	3.43	(781)	3.16	(109)	3.16
Outstanding – end of year	10,209	$ 3.09	8,721	$ 2.85	7,512	$ 2.85

The Company had stock options exercisable at December 31, 2003 of 5.4 million with a range of exercise prices from $.69 to $6.37. At December 31, 2002 and 2001, there were 4.0 million stock options exercisable, with a range of exercise prices from $0.69 to $6.37, and 3.2 million stock options exercisable from $0.69 to $4.50, respectively.

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

Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life(1)	Weighted Average Exercise Price
$0.69 to $1.63	2,674	3.78	$ 1.28
$1.75 to $4.38	6,516	7.42	3.35
$4.44 to $6.37	1,019	7.11	6.12
	10,209	6.44	$ 3.09

(1) Represents weighted average remaining contractual life in years.

(6) Segment Information and Accumulated Comprehensive Income

The Company manages its business as one reportable segment. Although the Company provides contract drilling services in several markets domestically, these operations have been aggregated into one reportable segment based on the similarity of economic characteristics among all markets including the nature of the services provided and the type of customers of such services.

Prior to the third quarter of 2001, the Company managed its business as two reportable segments; domestic operations and foreign operations. Late in the first quarter of 1999, the Company suspended all operations in Venezuela but retained the option to begin operations at any time. However, during the second quarter of 2001, the Company moved its five Venezuela rigs to the United States and in the third quarter of 2001 sold three of the five rigs for $1.3 million. This sale resulted in a gain of approximately $602,000. As a result of moving the Venezuela rigs to the United States, the Company realized $454,000 of previously unrealized foreign currency translation losses during the second quarter of 2001.

(7) Related-Party Transactions

The Company performed contract drilling services for affiliates of one of the Company's directors. Total revenues recognized from these affiliates during 2003, 2002 and 2001 were $4.1 million, $3.4 million and $6.0 million, respectively. During 2001, the Company also purchased equipment for $119,000 from an affiliate of the Chairman, President and Chief Executive Officer of the Company.

(8) Lease Commitments

Aggregate minimum lease payments required under noncancellable operating leases having terms greater than one year are as follows as of December 31, 2003: 2004 - $674,000; 2005 - $201,000; 2006 - $56,000; 2007 - $7,000; 2008 - $7,000; and $0 thereafter.

Lease expense under operating leases for 2003, 2002 and 2001 were approximately $718,000, $680,000 and $618,000, respectively.

(9) Contingencies

The Company is involved in litigation incidental to the conduct of its business, none of which management believes is, individually or in the aggregate, material to the Company's consolidated financial condition or results of operations.

(10) Employee Benefit Plan

The Company has a defined contribution employee benefit plan covering substantially all of its employees. The Company matches 100% of the first 3% of individual employee contributions and 50% of the next 3% of individual employee contributions. Employer matching contributions under the plan totaled $873,000, $1.3 million, and $1.3 million for the years ended December 31, 2003, 2002 and 2001, respectively. Participants vest in employer matching contributions over a five year period based upon service with the Company.

(11) Concentrations

Substantially all of the Company's contract drilling activities are conducted with independent and major oil and gas companies in the United States. Historically, the Company has not required collateral or other security to support the related receivables from such customers. However, the Company has required certain customers to deposit funds in escrow prior to the commencement of drilling. Actions typically taken by the Company in the event of nonpayment include filing a lien on the customer's producing property and filing suit against the customer.

For the three months ended December 31, 2003, the Company had one customer which represented approximately 11% of total revenue. For the year ended December 31, 2002, the Company also had one customer which represented approximately 11% of total revenue. There were no customers with revenue greater than 10% for the years ended December 31, 2003 and 2001.

(12) Provision for Asset Impairment

During the fourth quarter of 2002, the Company recorded a pre-tax non-cash asset impairment charge of $3.5 million in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." After review of rigs held for future refurbishment, the Company no longer intended to return five of those rigs to service, but instead decided to use their component parts as spare equipment inventory. This decision was made based upon the physical condition of the five rigs and the estimated cost of refurbishment. As such, an asset impairment charge was recorded to write the rigs down to their fair market value and the Company revised the number of drilling rigs in its fleet. The fair market value was based on an appraisal obtained from a third party appraiser.

GREY WOLF, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(13) Quarterly Financial Data (unaudited)

Summarized quarterly financial data for years ended December 31, 2003, 2002 and 2001 are set forth below (amounts in thousands, except per share amounts).

	Quarter Ended			
	March 2003	June 2003	September 2003	December 2003
Revenues	$ 62,387	$ 66,949	$ 72,383	$ 84,255
Gross profit (operating margin) (1)	7,102	7,380	7,866	19,339
Operating income (loss)	(8,435)	(7,892)	(7,678)	3,205
Loss before income taxes	(14,148)	(21,921)	(11,183)	(331)
Net income (loss)	(9,621)	(14,185)	(6,950)	556
Net income (loss) per common share - basic and diluted	(0.05)	(0.08)	(0.04)	0.00

	Quarter Ended			
	March 2002	June 2002	September 2002	December 2002
Revenues	$ 64,912	$ 62,854	$ 61,118	$ 61,376
Gross profit (operating margin) (1)	17,264	14,136	11,317	10,973
Operating income (loss)	2,655	(170)	(3,014)	(7,222)
Loss before income taxes	(2,756)	(5,544)	(8,626)	(12,767)
Net loss	(2,177)	(4,048)	(6,131)	(9,120)
Net loss per common share - basic and diluted	(0.01)	(0.02)	(0.03)	(0.05)

	Quarter Ended			
	March 2001	June 2001	September 2001	December 2001
Revenues	$ 101,136	$ 114,967	$ 128,030	$ 89,606
Gross profit (operating margin) (1)	39,624	53,008	58,481	33,993
Operating income	27,534	40,381	45,559	19,580
Income before income taxes	22,270	34,553	40,268	14,215
Net income	13,362	20,732	25,378	8,981
Net income per common share - basic and diluted	0.07	0.11	0.14	0.05

(1) Gross profit (operating margin) is computed as consolidated revenues less operating expenses (which excludes expenses for depreciation and general and administrative.

GREY WOLF, INC. AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS
(In thousands)

	Balance at Beginning of Period	Additions Charged to Allowance	Collections and Write-Offs	Balance at End of Period
Year Ended December 31, 2001				
Allowance for doubtful accounts receivable	$ 1,800	$ 695	$ (695)	$ 1,800
Year Ended December 31, 2002				
Allowance for doubtful accounts receivable	$ 1,800	$ 700	$ –	$ 2,500
Year Ended December 31, 2003				
Allowance for doubtful accounts receivable	$ 2,500	$ –	$ (57)	$ 2,443

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

As of December 31, 2003, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rule 13a-15. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective. Disclosure controls and procedures are controls and procedures that are designed to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms.

There have been no significant changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required by this item as to our directors and executive officers is hereby incorporated by reference to such information appearing under the captions "Directors" and "Executive Officers" in our definitive proxy statement for our 2004 Annual Meeting of Shareholders and is to be filed with the Securities and Exchange Commission (the "Commission") pursuant to the Securities Exchange Act of 1934 within 120 days of the end of our fiscal year on December 31, 2003.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item as to the compensation of our management is hereby incorporated by reference to such information appearing under the caption "Executive Compensation" in our definitive proxy statement for our 2004 Annual Meeting of Shareholders and is to be filed with the Commission pursuant to the Securities Exchange Act of 1934 within 120 days of the end of our fiscal year on December 31, 2003.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED SHAREHOLDERS' MATTERS

The information required by this item as to the ownership by our management and others of our securities is hereby incorporated by reference to such information appearing under the caption "Nominees for Director", "Ownership by Management and Certain Shareholders" and "Executive Compensation Plans" in our definitive proxy statement for our 2004 Annual Meeting of Shareholders and is to be filed with the Commission pursuant to the Securities Exchange Act of 1934 within 120 days of the end of our fiscal year on December 31, 2003.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by this item as to certain business relationships and transactions with our management and other parties related to us is hereby incorporated by reference to such information appearing under the caption "Certain Transactions" in our definitive proxy statement for our 2004 Annual Meeting of Shareholders and is to be filed with the Commission pursuant to the Securities Exchange Act of 1934 within 120 days of the end of our fiscal year on December 31, 2003.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item as to accounting fees and services is hereby incorporated by reference to such information appearing under the caption "Independent Auditors" in our definitive proxy statement for our 2004 Annual Meeting of Shareholders and is to be filed with the Commission pursuant to the Securities Exchange Act of 1934 within 120 days of the end of our fiscal year on December 31, 2003.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) The following documents are filed as part of this report:

1. and 2. Financial Statements and Schedule

The consolidated financial statements and supplemental schedule of Grey Wolf, Inc. and Subsidiaries are included in Part II, Item 8 and are listed in the Index to Consolidated Financial Statements and Financial Statement Schedule therein.

3. Exhibits

Exhibit No.		Documents
3.1	--	Articles of Incorporation of Grey Wolf, Inc., as amended (incorporated herein by reference to Exhibit 3.1 to Form 10-Q dated May 12, 1999).
3.2	--	By-Laws of Grey Wolf, Inc., as amended (incorporated herein by reference to Exhibit 99.1 to Form 8-K dated March 23, 1999).
4.1	--	Form of Trust Indenture, dated June 27, 1997, relating to the 8⅞% Senior Notes due 2007 by the Company and Texas Commerce Bank National Association, as Trustee (incorporated herein by reference to Exhibit 4.2 to the Company's Registration Statement on Form S-3 No. 333-26519 filed June 24, 1997).
4.2	--	Supplemental Indenture (to the Trust Indenture dated June 27, 1997), dated as of March 31, 1998, among the Company, the New Guarantor, the Existing Guarantors, and Chase Bank of Texas National Association, as Trustee. (incorporated herein by reference to Exhibit 4.5 to Form 8-K filed May 21, 1998).
4.3	--	Second Supplemental Indenture (to the Trust Indenture dated June 27, 1997), dated as of May 8, 1998, by and among the Company, the Guarantors, and Chase Bank of Texas, National Association, as Trustee (incorporated herein by reference to Exhibit 4.5 to Form 8-K filed May 21, 1998).
4.4	--	Third Supplemental Indenture (to the Trust Indenture dated June 27, 1997), dated as of January 4, 1999, among the Company, the New Guarantors, the Existing Guarantors, and Chase Bank of Texas, National Association, as Trustee (incorporated herein by reference to Grey Wolf, Inc. Annual Report on Form 10-K for the year ended December 31, 2001).
4.5	--	Form of Trust Indenture, dated May 8, 1998, relating to the 8⅞% Senior Notes due 2007 by and among the Company, the Guarantors, and Chase Bank of Texas, National Association, as Trustee (incorporated herein by reference to Exhibit 4.3 to Form 8-K filed May 21, 1998).
4.6	--	Supplemental Indenture (to the Trust Indenture dated May 8, 1998), dated as of January 4, 1999, among the Company, the New Guarantors, the Existing Guarantors and Chase Bank of Texas, National Association, as Trustee (incorporated herein by reference to Grey Wolf, Inc. Annual Report on From 10-K for the year ended December 31, 2001).
4.7	--	Rights Agreement dated as of September 21, 1998 by and between the Company and American Stock Transfer and Trust Company as Rights Agent (incorporated herein by reference to Exhibit 4.1 to Form 8-K filed September 22, 1998).

4.8	--	Indenture, dated as of May 7, 2003, relating to the 3.75% Contingent Convertible Senior Notes due 2023 between the Company, the Guarantors, and JPMorgan Chase Bank, a New York Banking Corporation, as Trustee (incorporated herein by reference to Exhibit 4.2 to the Company's Registration Statement on Form S-3 No. 333-106997 filed July 14, 2003).
4.9	--	Supplemental Indenture, dated as of May 22, 2003, relating to the 3.75% Contingent Convertible Senior Notes due 2023 between the Company, the Guarantors, and JPMorgan Chase Bank, a New York Banking Corporation, as Trustee (incorporated herein by reference to Exhibit 4.3 to the Company's Registration Statement on Form S-3 No. 333-106997 filed July 14, 2003).
10.1	--	Form of Non-Qualified Stock Option Agreement dated September 3, 1996, by and between the Company and Thomas P. Richards (incorporated herein by reference to Exhibit 10.2 to Registration Statement No. 333-14783).
10.2	--	Form of Incentive Stock Option Agreement dated September 3, 1996, by and between the Company and Ronnie E. McBride (incorporated herein by reference to Exhibit 10.14 to Post Effective Amendment No. 1 to Registration Statement No. 333-14783).
10.3	--	Form of Non-Qualified Stock Option Agreement dated September 3, 1996, by and between the Company and Ronnie E. McBride. (incorporated herein by reference to Exhibit 10.15 to Post Effective Amendment No. 1 to Registration Statement No. 333-14783).
10.4	--	Grey Wolf, Inc. 1996 Employee Stock Option Plan (incorporated herein by reference to Grey Wolf, Inc. 1996 Annual Meeting of Shareholders definitive proxy materials).
10.5	--	Grey Wolf Inc. Amendment to 1996 Employee Stock Option Plan (incorporated herein by reference to Grey Wolf, Inc. 1999 Annual Meeting of Shareholders definitive proxy materials filed April 9, 1999).
10.6	--	Grey Wolf, Inc. Second Amendment to 1996 Employee Stock Option Plan dated May 14, 2002 (incorporated herein by reference to Exhibit 4.6 to Grey Wolf, Inc. Registration Statement on Form S-8 No. 333-90888 filed June 21, 2002).
10.7	--	Drillers Inc. 1982 Stock Option and Long-Term Incentive Plan for Key Employees (incorporated by reference to Drillers Inc. 1982 Annual Meeting definitive proxy solicitation materials).
10.8	--	Form of Incentive Stock Option Agreement dated March 17, 1997, by and between the Company and Gary D. Lee (incorporated by reference to DI Industries, inc. Annual Report of Form 10-K for the year ended December 31, 1996).
10.9	--	Form of Non-Qualified Stock Option Agreement dated February 10, 1998, by and between the Company and David W. Wehlmann (incorporated herein by reference to Grey Wolf, Inc. Annual Report on Form 10-K for the year ended December 31, 1997).
10.10	--	Revolving Credit Agreement dated as of January 14, 1999 among Grey Wolf Drilling Company LP (as borrower), Grey Wolf, Inc. (as guarantor), The CIT Group/Business Credit, Inc. (as agent) and various financial institutions (as lenders). (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated January 26, 1999).
10.11	--	First Amendment to Loan Agreement dated as of December 20, 2001, by and among Grey Wolf Drilling Company, LP (as borrower) and Grey Wolf, Inc. (as guarantor) and the CIT Group/Business Credit, Inc. (as agent) and various financial institutions (as lenders) (incorporated herein by reference to Grey Wolf, Inc. Annual Report on Form 10-K for the year ended December 31, 2001).
10.12	--	Second Amendment to Loan Agreement dated as of February 7, 2003 by and among Grey Wolf Drilling Company L.P. (as borrower), Grey Wolf, Inc. and various subsidiaries (as guarantors) and the CIT Group/Business Credit, Inc. and various financial institutions (as lenders) (incorporated herein by reference to Grey Wolf, Inc. Annual Report on Form 10-K for the year ended December 31, 2002).

10.13	--	Non-Qualified Stock Option Agreement dated January 16, 1999, by and between the Company and Edward S. Jacob, III. (incorporated herein by reference to Grey Wolf, Inc. Annual Report on Form 10-K for the year ended December 31, 1999).
10.14	--	Form of Amendment to Non-Qualified Stock Option Agreements dated November 13, 2001, by and between the Company and Thomas P. Richards (incorporated herein by reference to Grey Wolf, Inc. Annual Report on Form 10-K for the year ended December 31, 2001).
10.15	--	Form of Amendment to Non-Qualified Stock Option Agreement dated November 13, 2001, by and among the Company (f.k.a. DI Industries, Inc.), Thomas P. Richards and Richards Brothers Interests, L.P (incorporated herein by reference to Grey Wolf, Inc. Annual Report on Form 10-K for the year ended December 31, 2001).
10.16	--	Form of Amendment to Non-Qualified Stock Option Agreements dated November 13, 2001, by and between the Company and each of David W. Wehlmann, Edward S. Jacob III, Gary D. Lee, Ronnie E. McBride, Merrie S. Costley, and Donald J. Guedry, Jr. (incorporated herein by reference to Grey Wolf, Inc. Annual Report on Form 10-K for the year ended December 31, 2001).
10.17	--	Grey Wolf, Inc. Executive Severance Plan effective November 15, 2001 (incorporated herein by reference to Grey Wolf, Inc. Annual Report on Form 10-K for the year ended December 31, 2001).
10.18	--	Amended and Restated Employment Agreement dated November 13, 2001, by and between the Company and Thomas P. Richards (incorporated herein by reference to Grey Wolf, Inc. Annual Report on Form 10-K for the year ended December 31, 2001).
10.19	--	Amended and Restated Employment Agreement dated November 13, 2001, by and between the Company and David W. Wehlmann (incorporated herein by reference to Grey Wolf, Inc. Annual Report on Form 10-K for the year ended December 31, 2001).
10.20	--	Amended and Restated Employment Agreement dated November 13, 2001, by and between the Company and Edward S. Jacob III (incorporated herein by reference to Grey Wolf, Inc. Annual Report on Form 10-K for the year ended December 31, 2001).
10.21	--	Amended and Restated Employment Agreement dated November 13, 2001, by and between the Company and Gary D. Lee (incorporated herein by reference to Grey Wolf, Inc. Annual Report on Form 10-K for the year ended December 31, 2001).
10.22	--	Employment Agreement effective March 31, 2003 by and between the Company and William E. Chiles (incorporated herein by reference to Grey Wolf, Inc. Quarterly Report on Form 10-Q for the quarter ended March 31, 2003).
10.23	--	Form of Non-Qualified Stock Option Agreement dated as of February 13, 2002, by and between the Company and each of Frank M. Brown, William T. Donovan, James K.B. Nelson, Robert E. Rose, Steven A. Webster, and William R. Ziegler (incorporated herein by reference to Grey Wolf, Inc. Annual Report on Form 10-K for the year ended December 31, 2001).
10.24	--	Grey Wolf, Inc. 2003 Incentive Plan (incorporated herein by reference to Grey Wolf, Inc. 2003 Annual Meeting of Shareholders definitive proxy materials).
*21.1	--	List of Subsidiaries of Grey Wolf, Inc.
*23.1	--	Consent of KPMG LLP
*31.1	--	Certification of Chief Executive Officer pursuant to Rule 13a-14(a).
*31.2	--	Certification of Chief Financial Officer pursuant to Rule 13a-14(a).
*32.1	--	Certification pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 of Thomas P. Richards, Chairman, President and Chief Executive Officer and David W. Wehlmann, Executive Vice President and Chief Financial Officer.

* Filed herewith

(b) Reports on Form 8-K

1. We furnished a Report on Form 8-K under Item 12 with the Securities and Exchange Commission on October 23, 2003 with regard to our press release announcing operating results for the quarter ended September 30, 2003.

2. We furnished a Report on Form 8-K under Item 12 with the Securities and Exchange Commission on February 2, 2004 with regard to our press release announcing operating results for the quarter and year ended December 31, 2003.

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, this 12th day of February, 2004.

Grey Wolf, Inc.

By: /s/ David W. Wehlmann
David W. Wehlmann, Executive Vice President and
Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signatures and Capacities	Date
By: /s/ Thomas P. Richards Thomas P. Richards, Chairman, President and Chief Executive Officer (Principal Executive Officer)	February 12, 2004
By: /s/ David W. Wehlmann David W. Wehlmann, Executive Vice President and Chief Financial Officer	February 12, 2004
By: /s/ Merrie S. Costley Merrie S. Costley, Vice President and Controller	February 12, 2004
By: /s/ William R. Ziegler William R. Ziegler, Director	February 12, 2004
By: /s/ Frank M. Brown Frank M. Brown, Director	February 12, 2004
By: /s/ William T. Donovan William T. Donovan, Director	February 12, 2004
By: /s/ James K. B. Nelson James K. B. Nelson, Director	February 12, 2004
By: /s/ Robert E. Rose Robert E. Rose, Director	February 12, 2004
By: /s/ Steven A. Webster Steven A. Webster, Director	February 12, 2004

Directors

Frank M. Brown
President
Fairweather International, Inc.
Anchorage, Alaska

William T. Donovan
Principal and Managing Director
Lubar & Company, Inc.
President, Chief Executive Officer
and Director
Total Logistics, Inc.
Milwaukee, Wisconsin

James K. B. Nelson
Felicity Ventures, Ltd.
Houston, Texas

Thomas P. Richards
Chairman, President and
Chief Executive Officer
Grey Wolf, Inc.
Houston, Texas

Robert E. Rose
Chairman
GlobalSantaFe Corporation
Houston, Texas

Steven A. Webster
Chairman
Carrizo Oil & Gas, Inc.
Managing Director
Global Energy Partners
Houston, Texas

William R. Ziegler
Vice Chairman
Grey Wolf, Inc.
Of Counsel to
Satterlee Stephens Burke &
Burke LLP
New York, New York

Officers

Thomas P. Richards
President and Chief Executive
Officer

William E. Chiles
Executive Vice President and
Chief Operating Officer

David W. Wehlmann
Executive Vice President and
Chief Financial Officer

Edward S. Jacob, III
Senior Vice President, Operations

Gary D. Lee
Senior Vice President,
Human Resources

Merrie S. Costley
Vice President and Controller

Donald J. Guedry, Jr.
Vice President and Treasurer

Subsidiary Officers

Forrest M. Conley, Jr.
Vice President, Ark-La-Tex

Ronald G. Hale
Senior Vice President,
Business Development

Joseph C. Hopewell
Vice President, Turnkey Services

Dale M. Love
Vice President, Gulf Coast

James Tolsma
Vice President, South Texas

Corporate Headquarters

10370 Richmond Ave., Suite 600
Houston, TX 77042-4136
(713) 435-6100
(713) 435-6170 (fax)
www.gwdrilling.com

Transfer Agent

American Stock Transfer & Trust
Company
59 Maiden Lane
New York, New York 10038
(800) 937-5449

Annual Meeting

Grey Wolf Inc.'s Annual Meeting of Shareholders will be held at 9:00 a.m. on May 11, 2004 at the:
Hilton
Houston Westchase and Towers
9999 Westheimer
Houston, Texas 77042-9990

Investor Relations

Shareholders are encouraged to contact the Company with questions or requests for information. Additional copies of the Company's Annual Report on Form 10-K as filed with the Securities and Exchange Commission are available without charge upon written request. Inquiries should be directed to:
Investor Relations
Grey Wolf, Inc.
10370 Richmond Ave., Suite 600
Houston, TX 77042-4136
(713) 435-6100
or through our website at
www.gwdrilling.com

Grey Wolf is traded on the American Stock Exchange under the symbol "GW."

This publication includes certain forward-looking statements reflecting Grey Wolf's expectations; however, many factors which may affect the actual results, including commodity prices, market and economic conditions, rig supply and demand and industry competition are difficult to predict. Accordingly, these forward-looking statements are subject to a number of risks and uncertainties and actual results and outcomes may differ materially. Please see our Annual Report on Form 10-K for the year ended December 31, 2003, included herein, for material factors that could cause actual results to vary.

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