PATTERSON-UTI 2006 ANNUAL REPORT

PATTERSON-UTI ENERGY, INC.

Financial Highlights (in thousands, except per share amounts – unaudited)

	Year Ended December 31,				
	2002	2003	2004	2005	**2006**
Revenues	$527,957	$ 776,170	$1,000,769	$1,740,455	**$2,546,586**
Operating income (loss)	(6,892)	66,282	148,467	581,296	**1,039,164**
Net income (loss)	(4,140)	43,187	94,346	372,740	**673,254**
Earnings (loss) per share					
Basic	(0.03)	0.27	0.57	2.19	**4.08**
Diluted	(0.03)	0.26	0.56	2.15	**4.02**
Cash dividends per share	—	—	0.06	0.16	**0.28**
Total assets	919,374	1,039,521	1,256,785	1,795,781	**2,192,503**
Long-term debt	—	—	—	—	**120,000**
Shareholders' equity	724,248	789,814	961,501	1,367,011	**1,562,466**
Working capital	166,885	198,399	235,480	382,448	**335,052**

Operational Highlights (dollars in thousands – unaudited)

	2002	2003	2004	2005	**2006**
Operating days	45,919	68,798	77,355	100,591	**108,192**
Average drilling revenue per day	$ 8.94	$ 9.30	$ 10.47	$ 14.77	**$ 20.05**
Average drilling margin per day[1]	$ 2.01	$ 2.39	$ 3.27	$ 7.05	**$ 10.79**
Average rigs operating	126	188	211	276	**296**

(1) Average margin per day represents average revenue per day minus average direct operating costs per day and excludes provisions for bad debts; other charges; depreciation, depletion, amortization and impairment; and selling, general and administrative expenses.

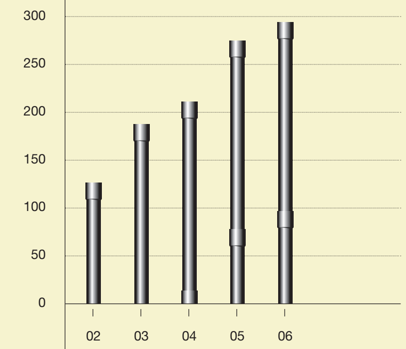
Patterson-UTI Energy, Inc. provides onshore contract drilling services to exploration and production companies in North America. The Company's land-based drilling rigs operate in oil and natural gas producing regions of

PATTERSON-UTI ENERGY, INC.

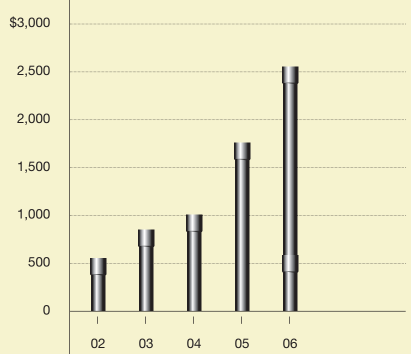
Table of Contents

Texas, New Mexico, Oklahoma, Arkansas, Louisiana, Mississippi, Colorado, Utah, Wyoming, Montana, North Dakota, South Dakota and western Canada. Patterson-UTI Energy, Inc. is also engaged in the businesses of pressure pumping services and drilling and completion fluid services.

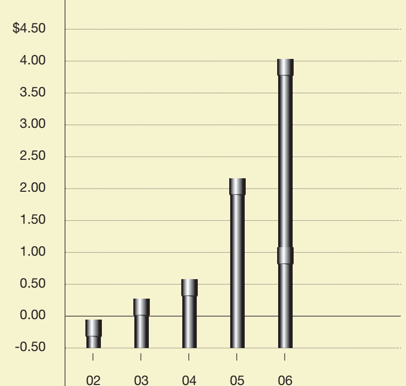
Average Drilling Rigs Operated
(for the year ended December 31)

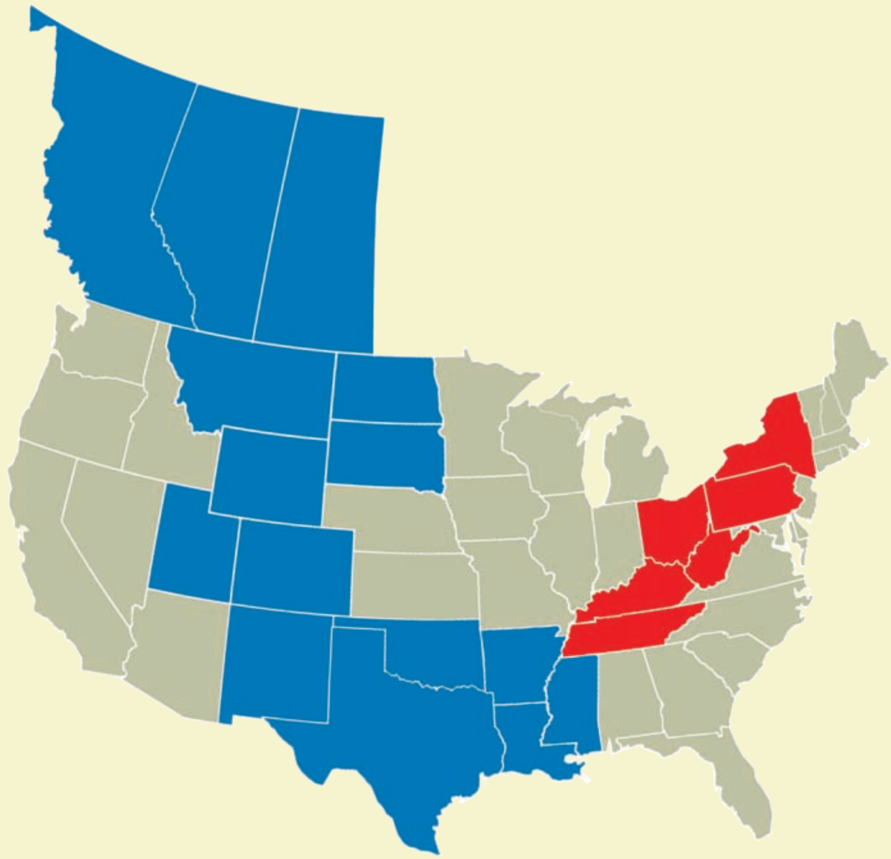


Revenues
(in millions of dollars)



Earnings Per Share
(in dollars)

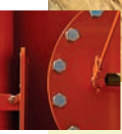




CONTRACT DRILLING

PRESSURE PUMPING

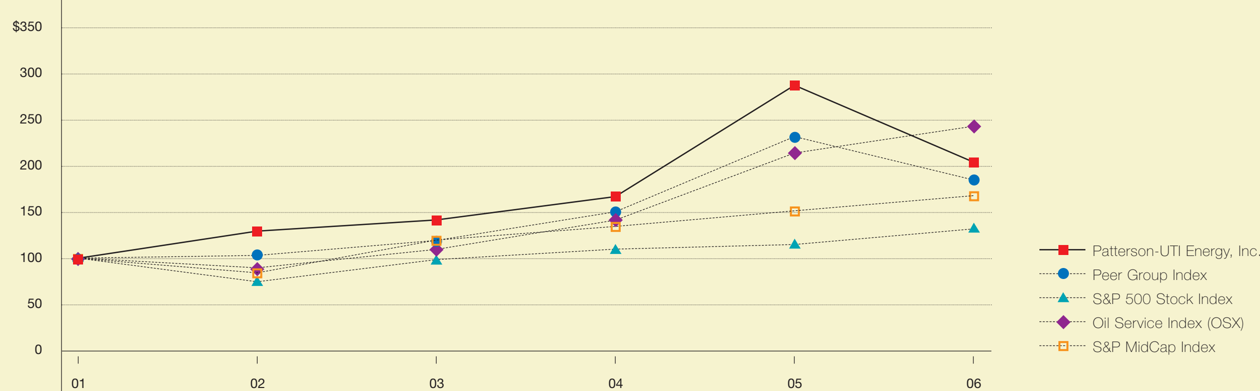
The Company also has a drilling and completion fluids business that operates offshore in the Gulf of Mexico and on land in Texas, New Mexico, Oklahoma and the Gulf Coast Region of Louisiana. Additionally, the Company has an exploration and production business that is based in Texas.



Performance Graph

The following graph compares the cumulative stockholder return on the Common Stock of Patterson-UTI, for the period from December 31, 2001 through December 31, 2006, with the cumulative total return of the Standard & Poors 500 Stock Index, the Standard & Poors MidCap Index, the Oilfield Service Index, and a Patterson-UTI determined peer group. Patterson-UTI's peer group consists of Grey Wolf, Inc., Helmerich & Payne, Inc., Nabors Industries, Ltd., Pioneer Drilling Co. and Unit Corp. All of the companies in Patterson-UTI's peer group are providers of land-based drilling services. The graph assumes investment of $100 on December 31, 2001 and reinvestment of all dividends.

Comparison of Cumulative Total Returns
(in dollars)



	Fiscal Year Ended December 31,					
Company/Index	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
Patterson-UTI Energy, Inc.	$100.00	$129.43	$141.27	$168.33	$286.79	$204.43
Peer Group Index	100.00	103.30	117.25	151.61	231.98	186.94
S&P 500 Stock Index	100.00	77.90	100.25	111.15	116.61	135.03
Oil Service Index (OSX)	100.00	91.51	107.58	143.75	215.51	244.30
S&P MidCap Index	100.00	85.49	115.94	135.05	152.00	167.69

The foregoing graph is based on historical data and is not necessarily indicative of future performance. This graph shall not be deemed to be "soliciting material" or to be "filed" with the SEC or subject to the Regulations of 14A or 14C under the Exchange Act or to the liabilities of Section 18 under such act.

Dear Fellow Shareholders:

We are pleased to report that Patterson-UTI Energy, Inc. has completed another record year, with record results in our contract drilling, pressure pumping and drilling and completion fluids operations.

Highlights From 2006

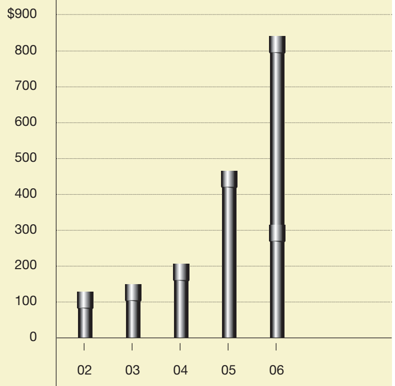
- Net income increased by 81 percent to a record $673 million, or $4.02 per share.
- Revenues were up by 46 percent to a record $2.5 billion.
- Record number of 296 average rigs operating.
- Record number of 331 total rigs operated.

Financial Highlights

2006 was our third successive record-breaking year at Patterson-UTI Energy. Our earnings increased by 81% on a 46% increase in revenues. Moreover, during the past four years, we have achieved compound annual growth rates (CAGR) of 35% in revenue, and more importantly, 99% in net income.

During 2006, we purchased $450 million of our common stock and doubled our quarterly dividend. The commitment to our dividend, and the stock buyback program, demonstrates our continuing commitment to deploy excess capital in a manner beneficial to our shareholders.

Cash Flow From Operating Activities
(in millions of dollars)



Successful Strategy

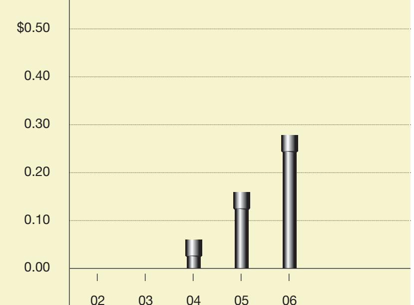
We believe these results are a direct result of our consistent commitment to position Patterson-UTI Energy for long-term growth and profitability. Our strategies for long-term growth, which began with increases to our drilling fleet through acquisitions in the mid-1990s, have evolved over time. In recent years, we have emphasized refurbishment of rigs, investment in drilling equipment upgrades and, beginning in 2007, we plan to assemble new rigs to prepare for increasing demand for drilling services.

Investment in Drilling Equipment

During the last four years, we have invested more than $1 billion in our contract drilling business, with the goal of providing our customers – in every market segment in which we compete – with a rig that is fit for each customer's specific drilling project. For example, we have engineered and deployed "walking" rigs capable of drilling as many as 28 wells at a single drilling pad site. These rigs are very efficient since they move within the drilling location fully assembled and without the use of trucks and cranes.

Over the past three years, we have refurbished 67 rigs which have provided our customers with "like-new" rigs. At the same time, the rig refurbishment program enabled us

Cash Dividends Per Share
(in dollars)



"As we see it, the trend to an increase in the number of natural gas wells drilled in the United States is likely to continue as the reserves that are found are likely to be smaller and more difficult to drill."

to expand our fleet of marketable rigs quickly and at a lower cost than assembling rigs with all new components. In 2007, we expect to complete the refurbishment of 15 additional rigs, which will bring our total of recently refurbished rigs to 82.

In addition to rig refurbishments, we have also invested heavily to upgrade and improve our other marketable rigs. Our expenditures have enhanced the capabilities of our drilling fleet in our continuing effort to stay ahead of the evolving and diverse needs of our various operating regions and customers.

New Rigs

In 2006, we ordered components for 15 new drilling rigs. Delivery of the components is scheduled throughout 2007 and will be assembled to our specifications. We are building these rigs based on the strong belief that long-term demand for oil and gas will require additional rigs be added to the market. As we see it, the trend to an increase in the number of natural gas wells drilled in the United States – a tripling of wells drilled from approximately 9,500 wells in 1996 to 31,500 wells in 2006 – is likely to continue as the reserves that are found are likely to be smaller and more difficult to drill. In essence, we believe the "large, low-hanging fruit" has been picked, and a long-term trend for more active rigs is likely to continue.

Pressure Pumping Operations

Our Universal Well Services subsidiary provides pressure pumping services to oil and natural gas operators primarily in the Appalachian Basin. Most wells drilled in the Appalachian Basin require some form of fracturing or stimulation to enhance the flow of oil and natural gas by pumping fluids into the well bore. We have expanded both the operating fleet and the geographic reach of this business. Our investments in equipment and personnel have borne fruit as Universal has achieved a 44% CAGR in operating income over the last four years.

Drilling and Completion Fluids Operations

Our Ambar Lone Star subsidiary enjoyed an increase in 2006 of approximately 57% in revenue and 136% in operating income. Most significantly, we have witnessed a turnaround in this segment as operating income moved from a small loss in 2003, to a small profit in 2004, and in 2006, a record level of operating income of approximately $29 million.

Current Environment

Although our results for 2006 were superb, they were impacted by the effects of warmer than normal temperatures during the winter months of calendar year 2006, which resulted in high levels of natural gas storage in the United States and decreases in natural gas prices. Customers of North American land drillers reacted by postponing projects and reducing their drilling activities during the last several months of 2006 and continuing into 2007.

We expect the combination of decreased drilling activity, along with the high production decline rates from existing wells, will reduce the natural gas supply and require increased drilling activity to avoid a shortfall of natural gas.

Long-Term Trends and Strategy

Looking ahead, we expect a substantial increase in the number of natural gas wells drilled in North America. We remain committed to an operating strategy in our contract drilling operations that has, at its core, quality service and an upgraded rig fleet to meet our customers' demands for increasingly complex wells and project specific needs. We believe that this strategy and our strong balance sheet will continue to serve our company well in the future.

Conclusion

The record results achieved in 2006 would not have been possible without the skill and dedication of our extremely talented workforce – from those who work with the drilling rigs and oilfield equipment to those who serve in administrative and support roles. We are aware that our success is dependent upon their contribution. We also wish to acknowledge the support that we have received from our fellow shareholders.

Respectfully submitted,

Mark S. Siegel
Chairman

Cloyce A. Talbott
President and
Chief Executive Officer

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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2006

or

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

For the transition period from to

Commission File Number 0-22664

Patterson-UTI Energy, Inc.
(Exact name of registrant as specified in its charter)

Delaware	**75-2504748**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
4510 Lamesa Highway, Snyder, Texas	**79549**
(Address of principal executive offices)	*(Zip Code)*

Registrant's telephone number, including area code:
(325) 574-6300

Securities Registered Pursuant to 12(b) of the Act:
None

Securities Registered Pursuant to 12(g) of the Act:
(Title of class)

Common Stock, $.01 Par Value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ or No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ or No ☑

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 is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2006, the last business day of the registrant's most recently completed second fiscal quarter, was $4,638,987,745, calculated by reference to the closing price of $28.31 for the common stock on the Nasdaq National Market on that date.

As of February 22, 2007, the registrant had outstanding 156,543,478 shares of common stock, $.01 par value, its only class of voting common stock.

Documents incorporated by reference:

Definitive Proxy Statement for the 2007 Annual Meeting of Stockholders (Part III).

FORWARD LOOKING STATEMENTS

This Annual Report on Form 10-K (including documents incorporated by reference herein) contains statements with respect to our expectations and beliefs as to future events. These types of statements are "forward-looking" and subject to uncertainties. Readers are cautioned that such forward-looking statements should be read in conjunction with our disclosures under the heading "Risk Factors," in Part I of this Report.

PART I

Item 1. *Business*

Available Information

This Annual Report on Form 10-K, along with our Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, are available free of charge through our Internet website (www.patenergy.com) as soon as reasonably practicable after we electronically file such material with, or furnish it to, the United States Securities and Exchange Commission ("SEC").

Overview

Based on publicly available information, we believe we are the second largest operator of land-based drilling rigs in North America. The Company was formed in 1978 and reincorporated in 1993 as a Delaware corporation. Our contract drilling business operates primarily in:

- Texas,
- New Mexico,
- Oklahoma,
- Arkansas,
- Louisiana,
- Mississippi,
- Colorado,
- Utah,
- Wyoming,
- Montana,
- North Dakota,
- South Dakota, and
- Western Canada (Alberta, British Columbia and Saskatchewan).

As of December 31, 2006, we had a drilling fleet that consisted of 336 currently marketable land-based drilling rigs. A drilling rig includes the structure, power source and machinery necessary to cause a drill bit to penetrate earth to a depth desired by the customer. A drilling rig is considered currently marketable at a point in time if it is operating or can be made ready to operate without significant capital expenditures. We also have a substantial inventory of drilling rig components and equipment which may be used in the activation of additional drilling rigs or as replacement parts for marketable rigs.

We provide pressure pumping services to oil and natural gas operators primarily in the Appalachian Basin. These services consist primarily of well stimulation and cementing for completion of new wells and remedial work on existing wells. We provide drilling fluids, completion fluids and related services to oil and natural gas operators offshore in the Gulf of Mexico and on land in Texas, Southeastern New Mexico, Oklahoma and the Gulf Coast region of Louisiana. Drilling and completion fluids are used by oil and natural gas operators during the drilling process to control pressure when drilling oil and natural gas wells. We are also engaged in the development, exploration, acquisition and production of oil and natural gas. Our oil and natural gas operations are focused primarily in producing regions of West and South Texas, Southeastern New Mexico, Utah and Mississippi.

Industry Segments

Our revenues, operating profits and identifiable assets are primarily attributable to four industry segments:

- contract drilling,
- pressure pumping services,
- drilling and completion fluids services, and
- oil and natural gas development, exploration, acquisition and production.

All of our industry segments had operating profits in 2006, 2005 and 2004.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 15 of Notes to Consolidated Financial Statements included as a part of Items 7 and 8, respectively, of this Report for financial information pertaining to these industry segments.

Contract Drilling Operations

General — We market our contract drilling services to major and independent oil and natural gas operators. As of December 31, 2006, we had 336 currently marketable land-based drilling rigs which were based in the following regions:

- 107 in the Permian Basin region (West Texas and Southeastern New Mexico),
- 50 in South Texas,
- 44 in the Ark-La-Tex region and Mississippi,
- 67 in the Mid-Continent region (Oklahoma and North Central Texas),
- 48 in the Rocky Mountain region (Colorado, Utah, Wyoming, Montana, North Dakota and South Dakota), and
- 20 in Western Canada (Alberta, British Columbia and Saskatchewan).

Our marketable drilling rigs have rated maximum depth capabilities ranging from 5,000 feet to 30,000 feet. Fifty-six of these drilling rigs are SCR electric rigs and 280 are mechanical rigs. An electric rig differs from a mechanical rig in that the electric rig converts the diesel power (the sole energy source for a mechanical rig) into electricity to power the rig. We also have a substantial inventory of drilling rig components and equipment which may be used in the activation of additional drilling rigs or as replacement parts for marketable rigs.

Drilling rigs are typically equipped with:

- engines,
- drawworks or hoists,
- derricks or masts,
- pumps to circulate the drilling fluid,
- blowout preventers,
- drill string (pipe), and
- other related equipment.

Over time, components on a drilling rig are replaced or rebuilt. We spend significant funds each year on an ongoing program to modify and upgrade our drilling rigs to ensure that our drilling equipment is well maintained and competitive. We have spent $1 billion during the last three years on capital improvements to modify and upgrade our drilling rigs. During fiscal years 2006, 2005 and 2004, we spent approximately $531 million, $329 million and $141 million, respectively, on these capital improvements.

Depth and complexity of the well and drill site conditions are the principal factors in determining the size of drilling rig used for a particular job. We use our rigs for developmental and exploratory drilling, and they are capable of vertical or horizontal drilling.

Our contract drilling operations depend on the availability of:

- drill pipe,
- bits,
- replacement parts and other related rig equipment,
- fuel, and
- qualified personnel,

some of which have been in short supply from time to time.

Drilling Contracts — Most of our drilling contracts are with established customers on a competitive bid or negotiated basis. Typically, the contracts are short-term to drill a single well or a series of wells. Customer demand for drilling contracts with a term of one or more years increased during 2005 due to the scarcity of available drilling rigs in the market place. In response to this demand, we entered into several long-term contracts in 2005 and 2006. These long-term contracts provide for the use of drilling rigs for fixed periods of time during which multiple wells are drilled. During 2006, our average number of days to drill a well was approximately 21 days. We may continue to enter into long-term contracts when considered beneficial to the Company.

The drilling contracts obligate us to provide and operate a drilling rig and to pay certain operating expenses, including wages of drilling personnel and necessary maintenance expenses. Most drilling contracts are subject to termination by the customer on short notice. We generally indemnify our customers against claims by our employees and claims that might arise from surface pollution caused by spills of fuel, lubricants and other solvents within our control. The customers generally indemnify us against claims that might arise from other surface and subsurface pollution, except claims that might arise from our gross negligence.

The contracts provide for payment on a daywork, footage, or turnkey basis, or a combination thereof. In each case, we provide the rig and crews. Our bid for each contract depends upon:

- location, depth and anticipated complexity of the well,
- on-site drilling conditions,
- equipment to be used,
- estimated risks involved,
- estimated duration of the job,
- availability of drilling rigs, and
- other factors particular to each proposed well.

Daywork Contracts

Under daywork contracts, we provide the drilling rig and crew to the customer. The customer supervises the drilling of the well. Our compensation is based on a contracted rate per day during the period the drilling rig is utilized. We sometimes receive a lower rate when the drilling rig is moving, or when drilling operations are interrupted or restricted by adverse weather conditions or other conditions beyond our control. Daywork contracts typically provide separately for mobilization of the drilling rig.

Footage Contracts

Under footage contracts, we contract to drill a well to a certain depth under specified conditions for a fixed price per foot. The customer provides drilling fluids, casing, cementing and well design expertise. These contracts require us to bear the cost of services and supplies that we provide until the well has been drilled to the agreed depth. If we drill the well in less time than estimated, we have the opportunity to improve our profits over those that would be attainable under a daywork contract. Profits are reduced and losses may be incurred if the well requires more days to drill to the contracted depth than estimated. Footage contracts generally contain greater risks for a drilling contractor than daywork contracts. Under footage contracts, the drilling contractor assumes certain risks associated with loss of the well from fire, blowouts and other risks. Due to current market conditions and improved rates received under daywork contracts, we are entering into fewer footage contracts than we did in the past.

Turnkey Contracts

Under turnkey contracts, we contract to drill a well to a certain depth under specified conditions for a fixed fee. In a turnkey arrangement, we are required to bear the costs of services, supplies and equipment beyond those typically provided under a footage contract. In addition to the drilling rig and crew, we are required to provide the drilling and completion fluids, casing, cementing, and the technical well design and engineering services during the drilling process. We also assume certain risks associated with drilling the well such as fires, blowouts, cratering of the well bore and other such risks. Compensation occurs only when the agreed scope of the work has been completed, which requires us to make larger up-front working capital commitments prior to receiving payments under a turnkey drilling contract. Under a turnkey contract, we have the opportunity to improve our profits if the drilling process goes as expected and there are no complications or time delays. However, given the increased exposure we have under a turnkey contract, profits can be significantly reduced and losses can be incurred if complications or delays occur during the drilling process. Turnkey contracts generally involve the highest degree of risk among the three different types of drilling contracts: daywork, footage and turnkey. Due to current market conditions and improved rates received under daywork contracts, we are entering into fewer turnkey contracts than we did in the past.

Revenues by Contract Type — Information regarding our revenues by contract type for the last three years follows:

	Year Ended December 31,		
Type of Revenues	**2006**	**2005**	**2004**
Daywork	100%	98%	88%
Footage	0	1	6
Turnkey	0	1	6

Contract Drilling Activity — Information regarding our contract drilling activity for the last three years follows:

	Year Ended December 31,		
	2006	**2005**	**2004**
Average rigs operating(1)	296	276	211
Number of rigs operated	331	307	259
Number of wells drilled	5,050	4,594	3,534
Number of operating days	108,221	100,591	77,355

(1) A rig is operating when it is drilling, being moved, assembled, dismantled or otherwise earning revenue under contract.

Drilling Rigs and Related Equipment — Certain drilling rig information with respect to rigs that were currently marketable as of December 31, 2006 follows:

Depth Rating (Ft.)	Mechanical	Electric	Total
5,000 to 9,999	33	—	33
10,000 to 11,999	49	3	52
12,000 to 13,999	60	5	65
14,000 to 15,999	120	21	141
16,000 to 30,000	18	27	45
Totals	280	56	336

At December 31, 2006, we owned and operated 336 trucks and 439 trailers used to rig down, transport and rig up our drilling rigs. Our ownership of trucks and trailers reduces our dependency upon third parties for these services and enhances the efficiency of our contract drilling operations particularly in periods of high drilling rig utilization.

Most repair and overhaul work to our drilling rig equipment is performed at our yard facilities located in Texas, New Mexico, Oklahoma, Wyoming, Utah and Western Canada.

Pressure Pumping Operations

General — We provide pressure pumping services to oil and natural gas operators primarily in the Appalachian Basin. Pressure pumping services are primarily well stimulation and cementing for the completion of new wells and remedial work on existing wells. Most wells drilled in the Appalachian Basin require some form of fracturing or other stimulation to enhance the flow of oil and natural gas by pumping fluids under pressure into the well bore. Generally, Appalachian Basin wells require cementing services before production commences. The cementing process inserts material between the wall of the well bore and the casing to center and stabilize the casing.

Equipment — Our pressure pumping equipment at December 31, 2006 follows:

- 36 cement pumper trucks,
- 35 fracturing pumper trucks,
- 37 nitrogen pumper trucks,
- 20 blender trucks,
- 7 bulk acid trucks,
- 44 bulk cement trucks,
- 14 bulk nitrogen trucks,
- 3 bulk nitrogen trailers,
- 40 bulk sand trucks,
- 21 connection trucks,
- 3 acid pumper trucks, and
- 10 sand pneumatic trucks.

Drilling and Completion Fluids Operations

General — We provide drilling fluids, completion fluids and related services to oil and natural gas operators offshore in the Gulf of Mexico and on land in Texas, Southeastern New Mexico, Oklahoma and the Gulf Coast region of Louisiana. We serve our offshore customers through six stockpoint facilities located along the Gulf of

Mexico in Texas and Louisiana and our land-based customers through eleven stockpoint facilities in Texas, Louisiana, Oklahoma and New Mexico.

Drilling Fluids — Drilling fluid products and systems are used to cool and lubricate the bit during drilling operations, contain formation pressures (thereby minimizing blowout risk), suspend and remove rock cuttings from the hole and maintain the stability of the wellbore. Technical services are provided to ensure that the products and systems are applied effectively to optimize drilling operations.

Completion Fluids — After a well is drilled, the well casing is set and cemented into place. At that point, the drilling fluid services are complete and the drilling fluids are circulated out of the well and replaced with completion fluids. Completion fluids, also known as clear brine fluids, are solids-free, clear salt solutions that have high specific gravities. Combined with a range of specialty chemicals, these fluids are used to control bottom-hole pressures and to meet specific corrosion, inhibition, viscosity and fluid loss requirements.

Raw Materials — Our drilling and completion fluids operations depend on the availability of the following raw materials:

Drilling

barite and bentonite

Completion

calcium chloride, calcium bromide and zinc bromide

We obtain these raw materials through purchases made on the spot market and supply contracts with producers of these raw materials.

Barite Grinding Facility — We own and operate a barite grinding facility with two barite grinding mills in Houma, Louisiana. This facility allows us to grind raw barite into the powder additive used in drilling fluids.

Other Equipment — We operate 20 trucks and 83 trailers and lease another 33 trucks which are used to transport drilling and completion fluids and related equipment.

Oil and Natural Gas Operations

General — We are engaged in the development, exploration, acquisition and production of oil and natural gas. Our oil and natural gas business operates primarily in producing regions of West and South Texas, Southeastern New Mexico, Utah and Mississippi. We significantly expanded our oil and natural gas operations in 2004 through our acquisition of TMBR/Sharp Drilling, Inc. (“TMBR”). The oil and natural gas assets acquired in the acquisition of TMBR included both proved reserves and undeveloped properties.

Customers

The customers of each of our four business segments are oil and natural gas operators or purchasers of these commodities. Our customer base includes both major and independent oil and natural gas operators. During 2006, no single customer accounted for 10% or more of our consolidated operating revenues.

Competition

Contract Drilling and Pressure Pumping Businesses — Our land drilling and pressure pumping businesses are highly competitive. At times, available land drilling rigs and pressure pumping equipment exceed the demand for such equipment. The equipment can also be moved from one market to another in response to market conditions.

Drilling and Completion Fluids Business — The drilling and completion fluids industry is highly competitive and price is generally the most important factor. Other competitive factors include the availability of chemicals and experienced personnel, the reputation of the fluids services provider in the drilling industry and relationships with customers. Some of our competitors have substantially more resources and longer operating histories than we have.

Oil and Natural Gas Business — There is substantial competition for the acquisition of oil and natural gas leases suitable for development and exploration and for experienced personnel. Our competitors in this business include:

- major integrated oil and natural gas operators,
- independent oil and natural gas operators, and
- drilling and production purchase programs.

Our ability to increase our oil and natural gas reserves in the future is directly dependent upon our ability to select, acquire and develop suitable prospects. Many of our competitors have facilities and financial and human resources greater than ours.

Government and Environmental Regulation

All of our operations and facilities are subject to numerous Federal, state, foreign, and local laws, rules and regulations related to various aspects of our business, including:

- drilling of oil and natural gas wells,
- containment and disposal of hazardous materials, oilfield waste, other waste materials and acids,
- use of underground storage tanks, and
- use of underground injection wells.

To date, applicable environmental laws and regulations have not required the expenditure of significant resources. We do not anticipate any material capital expenditures for environmental control facilities or extraordinary expenditures to comply with environmental rules and regulations in the foreseeable future. However, compliance costs under existing laws or under any new requirements could become material, and we could incur liability in any instance of noncompliance.

Our business is generally affected by political developments and by Federal, state, foreign, and local laws and regulations that relate to the oil and natural gas industry. The adoption of laws and regulations affecting the oil and natural gas industry for economic, environmental and other policy reasons could increase costs relating to drilling and production. They could have an adverse effect on our operations. Several state and Federal environmental laws and regulations currently apply to our operations and may become more stringent in the future.

We use operating and disposal practices that are standard in the industry. However, hydrocarbons and other materials may have been disposed of or released in or under properties currently or formerly owned or operated by us or our predecessors. In addition, some of these properties have been operated by third parties over whom we have no control of their treatment of hydrocarbon and other materials or the manner in which they may have disposed of or released such materials.

The Federal Comprehensive Environmental Response Compensation and Liability Act of 1980, as amended, commonly known as CERCLA, and comparable state statutes impose strict liability on:

- owners and operators of sites, and
- persons who disposed of or arranged for the disposal of "hazardous substances" found at sites.

The Federal Resource Conservation and Recovery Act ("RCRA"), as amended, and comparable state statutes govern the disposal of "hazardous wastes." Although CERCLA currently excludes petroleum from the definition of "hazardous substances," and RCRA also excludes certain classes of exploration and production wastes from regulation, such exemptions by Congress under both CERCLA and RCRA may be deleted, limited, or modified in the future. If such changes are made to CERCLA and/or RCRA, we could be required to remove and remediate previously disposed of materials (including materials disposed of or released by prior owners or operators) from properties (including ground water contaminated with hydrocarbons) and to perform removal or remedial actions to prevent future contamination.

The Federal Water Pollution Control Act and the Oil Pollution Act of 1990, as amended, and implementing regulations govern:

- the prevention of discharges, including oil and produced water spills, and
- liability for drainage into waters.

The Oil Pollution Act is more comprehensive and stringent than previous oil pollution liability and prevention laws. It imposes strict liability for a comprehensive and expansive list of damages from an oil spill into waters from facilities. Liability may be imposed for oil removal costs and a variety of public and private damages. Penalties may also be imposed for violation of Federal safety, construction and operating regulations, and for failure to report a spill or to cooperate fully in a clean-up.

The Oil Pollution Act also expands the authority and capability of the Federal government to direct and manage oil spill clean-up and operations, and requires operators to prepare oil spill response plans in cases where it can reasonably be expected that substantial harm will be done to the environment by discharges on or into navigable waters. We have spill prevention control and countermeasure plans in place for our oil and natural gas properties in each of the areas in which we operate and for each of the stockpoints operated by our drilling and completion fluids business. Failure to comply with ongoing requirements or inadequate cooperation during a spill event may subject a responsible party, such as us, to civil or criminal actions. Although the liability for owners and operators is the same under the Federal Water Pollution Act, the damages recoverable under the Oil Pollution Act are potentially much greater and can include natural resource damages.

Our operations are also subject to Federal, state and local regulations for the control of air emissions. The Federal Clean Air Act, as amended, and various state and local laws impose certain air quality requirements on us. Amendments to the Clean Air Act revised the definition of "major source" such that emissions from both wellhead and associated equipment involved in oil and natural gas production may be added to determine if a source is a "major source." As a consequence, more facilities may become major sources and thus would be required to obtain operating permits. This permitting process may require capital expenditures in order to comply with permit limits.

Risks and Insurance

Our operations are subject to the many hazards inherent in the drilling business, including:

- accidents at the work location,
- blow-outs,
- cratering,
- fires, and
- explosions.

These hazards could cause:

- personal injury or death,
- suspension of drilling operations, or
- serious damage or destruction of the equipment involved and, in addition to environmental damage, could cause substantial damage to producing formations and surrounding areas.

Damage to the environment, including property contamination in the form of either soil or ground water contamination, could also result from our operations, particularly through:

- oil or produced water spillage,
- natural gas leaks, and
- fires.

In addition, we could become subject to liability for reservoir damages. The occurrence of a significant event, including pollution or environmental damages, could materially affect our operations and financial condition.

As a protection against operating hazards, we maintain insurance coverage we believe to be adequate, including:

- all-risk physical damages,
- employer's liability,
- commercial general liability, and
- workers compensation insurance.

We believe that we are adequately insured for public liability and property damage to others with respect to our operations. However, such insurance may not be sufficient to protect us against liability for all consequences of:

- personal injury,
- well disasters,
- extensive fire damage,
- damage to the environment, or
- other hazards.

We also carry insurance coverage for major physical damage to our drilling rigs. However, we do not carry insurance against loss of earnings resulting from such damage. In view of the difficulties that may be encountered in renewing such insurance at reasonable rates, no assurance can be given that:

- we will be able to maintain the type and amount of coverage that we believe to be adequate at reasonable rates, or
- any particular types of coverage will be available.

In addition to insurance coverage, we also attempt to obtain indemnification from our customers for certain risks. These indemnity agreements typically require our customers to hold us harmless in the event of loss of production or reservoir damage. These contractual indemnifications may not be supported by adequate insurance maintained by the customer.

Employees

We had approximately 9,000 full-time employees at December 31, 2006. The number of employees fluctuates depending on the current and expected demand for our services. We consider our employee relations to be satisfactory. None of our employees are represented by a union.

Seasonality

Seasonality does not significantly affect our overall operations. However, our pressure pumping division in Appalachia and our drilling operations in Canada are subject to slow periods of activity during the Spring thaw. In addition, our drilling operations in Canada are subject to slow periods of activity during the Fall.

Raw Materials and Subcontractors

We use many suppliers of raw materials and services. These materials and services have historically been available, although there is no assurance that such materials and services will continue to be available on favorable terms or at all. We also utilize numerous independent subcontractors from various trades.

Item 1A. ***Risk Factors.***

From time to time, we make written or oral forward-looking statements, including statements contained in this Annual Report on Form 10-K, our other filings with the SEC, press releases and reports to stockholders. These forward-looking statements are made pursuant to the "Safe Harbor" provisions of the Private Securities Litigation Reform Act of 1995. These statements include, without limitation, statements relating to liquidity, financing of operations, sources and sufficiency of funds and impact of inflation. The words "believes," "budgeted," "expects," "project," "will," "could," "may," "plans," "intends," "strategy," or "anticipates," and similar expressions are used to identify our forward-looking statements. We do not undertake to update, revise, or correct any of our forward-looking information.

We include the following cautionary statement in accordance with the "Safe Harbor" provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statement made by us, or on our behalf. The factors identified in this cautionary statement are important factors (but not necessarily all of the important factors) that could cause actual results to differ materially from those expressed in any forward-looking statement made by us, or on our behalf. Where any such forward-looking statement includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that, while we believe such assumptions or bases to be reasonable and make them in good faith, assumed facts or bases almost always vary from actual results. The differences between assumed facts or bases and actual results can be material, depending upon the circumstances.

Where, in any forward-looking statement, we express an expectation or belief as to the future results, such expectation or belief is expressed in good faith and believed to have a reasonable basis. However, there can be no assurance that the statement of expectation or belief will result, or be achieved or accomplished. Taking this into account, the following are identified as important risk factors currently applicable to, or which could readily be applicable to, us:

We are Dependent on the Oil and Natural Gas Industry and Market Prices for Oil and Natural Gas. Declines in Oil and Natural Gas Prices Have Adversely Affected Our Operations.

Our revenue, profitability and rate of growth are substantially dependent upon prevailing prices for oil and natural gas. For many years, oil and natural gas prices and, therefore, the level of drilling, exploration, development and production, have been extremely volatile. Prices are affected by:

- market supply and demand,
- international military, political and economic conditions, and
- the ability of the Organization of Petroleum Exporting Countries, commonly known as OPEC, to set and maintain production and price targets.

All of these factors are beyond our control. The average market price of natural gas has improved from $3.36 in 2002 to $6.94 in 2006 resulting in an increase in demand for our drilling services. Our average number of rigs operating increased from 126 in 2002 to 296 in 2006. We expect oil and natural gas prices to continue to be volatile and to affect our financial condition and operations and ability to access sources of capital. A significant decrease in market prices for natural gas would likely result in a material decrease in demand for drilling rigs and reduction in our operating results.

A General Excess of Operable Land Drilling Rigs Adversely Affects Our Profit Margins Particularly in Times of Weaker Demand.

The North American land drilling industry has experienced periods of downturn in demand over the last decade. During these periods, there have been substantially more drilling rigs available than necessary to meet demand. As a result, drilling contractors have had difficulty sustaining profit margins during the downturn periods.

In addition to adverse effects that future declines in demand could have on us, ongoing factors which could adversely affect utilization rates and pricing, even in an environment of high oil and natural gas prices and increased drilling activity, include:

- movement of drilling rigs from region to region,
- reactivation of land-based drilling rigs, or
- construction of new drilling rigs.

As a result of an increase in drilling activity and increased prices for drilling services, construction of new drilling rigs has increased significantly. We cannot predict either the future level of demand for our contract drilling services or future conditions in the oil and natural gas contract drilling business.

Shortages of Drill Pipe, Replacement Parts and Other Related Rig Equipment Adversely Affects Our Operating Results.

During periods of increased demand for drilling services, the industry has experienced shortages of drill pipe, replacement parts and other related rig equipment. These shortages can cause the price of these items to increase significantly and require that orders for the items be placed well in advance of expected use. These price increases and delays in delivery may require us to increase capital and repair expenditures in our contract drilling segment. Severe shortages could impair our ability to operate our drilling rigs.

The Various Business Segments in Which We Operate Are Highly Competitive with Excess Capacity which may Adversely Affect Our Operating Results.

Our land drilling and pressure pumping businesses are highly competitive. At times, available land drilling rigs and pressure pumping equipment exceed the demand for such equipment. This excess capacity has resulted in substantial competition for drilling and pressure pumping contracts. The fact that drilling rigs and pressure pumping equipment are mobile and can be moved from one market to another in response to market conditions heightens the competition in the industry.

We believe that price competition for drilling and pressure pumping contracts will continue for the foreseeable future due to the existence of available rigs and pressure pumping equipment.

In recent years, many drilling and pressure pumping companies have consolidated or merged with other companies. Although this consolidation has decreased the total number of competitors, we believe the competition for drilling and pressure pumping services will continue to be intense.

The drilling and completion fluids services industry is highly competitive. Price is generally the most important factor. Other competitive factors include the availability of chemicals and experienced personnel, the reputation of the fluids services provider in the drilling industry and relationships with customers. Some of our competitors have substantially more resources and longer operating histories than we have.

Labor Shortages Adversely Affect Our Operating Results.

During periods of increasing demand for contract drilling services, the industry experiences shortages of qualified drilling rig personnel. During these periods, our ability to attract and retain sufficient qualified personnel to market and operate our drilling rigs is adversely affected, which negatively impacts both our operations and profitability. Operationally, it is more difficult to hire qualified personnel which adversely affects our ability to mobilize inactive rigs in response to the increased demand for our contract drilling services. Additionally, wage rates for drilling personnel are likely to increase, resulting in higher operating costs.

Continued Growth Through Rig Acquisition is Not Assured.

We have increased our drilling rig fleet in the past through mergers and acquisitions. The land drilling industry has experienced significant consolidation, and there can be no assurance that acquisition opportunities will be available in the future. Additionally, we are likely to continue to face intense competition from other companies for available acquisition opportunities.

There can be no assurance that we will:

- have sufficient capital resources to complete additional acquisitions,
- successfully integrate acquired operations and assets,
- effectively manage the growth and increased size,
- successfully deploy idle or stacked rigs,
- maintain the crews and market share to operate drilling rigs acquired, or
- successfully improve our financial condition, results of operations, business or prospects in any material manner as a result of any completed acquisition.

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 would be dilutive to existing stockholders. Also, continued growth could strain our management, operations, employees and other resources.

The Nature of our Business Operations Presents Inherent Risks of Loss that, if not Insured or Indemnified Against, Could Adversely Affect Our Operating Results.

Our operations are subject to many hazards inherent in the contract drilling, pressure pumping, and drilling and completion fluids businesses, which in turn could cause personal injury or death, work stoppage, or serious damage to our equipment. Our operations could also cause environmental and reservoir damages. We maintain insurance coverage and have indemnification agreements with many of our customers. However, there is no assurance that such insurance or indemnification agreements would adequately protect us against liability or losses from all consequences of these hazards. Additionally, there can be no assurance that insurance would be available to cover any or all of these risks, or, even if available, that insurance premiums or other costs would not rise significantly in the future, so as to make such insurance prohibitive.

We have elected in some cases to accept a greater amount of risk through increased deductibles on certain insurance policies. For example, we maintain a $1.0 million per occurrence deductible on our workers' compensation, general liability and equipment insurance coverages.

Violations of Environmental Laws and Regulations Could Materially Adversely Affect Our Operating Results.

The drilling of oil and natural gas wells is subject to various Federal, state, foreign, and local laws, rules and regulations. The cost of compliance with these laws and regulations could be substantial. A failure to comply with these requirements could expose us to substantial civil and criminal penalties. In addition, Federal law imposes a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages from such spills. As an owner and operator of land-based drilling rigs, we may be deemed to be a responsible party under Federal law. Our operations and facilities are subject to numerous state and Federal environmental laws, rules and regulations, including, without limitation, laws concerning the containment and disposal of hazardous substances, oil field waste and other waste materials, the use of underground storage tanks and the use of underground injection wells.

Some of Our Contract Drilling Services are Provided Under Turnkey and Footage Contracts, Which are Financially Risky.

A portion of our contract drilling is performed under turnkey and footage contracts, which involve significant risks. Under turnkey drilling contracts, we contract to drill a well to a certain depth under specified conditions at a fixed price. Under footage contracts, we contract to drill a well to a certain depth under specified conditions at a fixed price per foot. The risk to us under these types of drilling contracts are greater than on a well drilled on a daywork basis. Unlike daywork contracts, we must bear the cost of services until the target depth is reached. In addition, we must assume most of the risk associated with the drilling operations, generally assumed by the operator of the well on a daywork contract, including blowouts, loss of hole from fire, machinery breakdowns and abnormal drilling conditions. Accordingly, if severe drilling problems are encountered in drilling wells under such contracts, we could suffer substantial losses.

Anti-takeover Measures in Our Charter Documents and Under State Law Could Discourage an Acquisition and Thereby Affect the Related Purchase Price.

We are a Delaware corporation subject to the Delaware General Corporation Law, including Section 203, an anti-takeover law enacted in 1988. We have also enacted certain anti-takeover measures, including a stockholders' rights plan. In addition, our Board of Directors has the authority to issue up to one million shares of preferred stock and to determine the price, rights (including voting rights), conversion ratios, preferences and privileges of that stock without further vote or action by the holders of the common stock. As a result of these measures and others, potential acquirers might find it more difficult or be discouraged from attempting to effect an acquisition transaction with us. This may deprive holders of our securities of certain opportunities to sell or otherwise dispose of the securities at above-market prices pursuant to any such transactions.

Item 1B. *Unresolved Staff Comments.*

None.

Item 2. *Properties*

Our corporate headquarters are located in Snyder, Texas. We also have a number of offices, yards and stockpoint facilities located in our various operating areas.

Our corporate headquarters are located at 4510 Lamesa Highway, Snyder, Texas, and our telephone number at that address is (325) 574-6300. There are a number of improvements at our headquarters, including:

- office buildings with approximately 37,000 square feet of office space and storage,
- a shop facility with approximately 7,000 square feet used for drilling equipment repairs and metal fabrication,
- a truck shop facility with approximately 10,000 square feet used to maintain, overhaul and repair our truck fleet,
- a truck fabrication and rigup shop with approximately 3,000 square feet used to prepare new trucks for service,
- an engine shop facility with approximately 20,000 square feet used to overhaul and repair the engines that power our drilling rigs, and
- a welding shop with approximately 10,000 square feet.

We have regional administrative offices, yards and stockpoint facilities in many of the areas in which we operate. The facilities are primarily used to support day-to-day operations, including the repair and maintenance of equipment as well as the storage of equipment, inventory and supplies and to facilitate administrative responsibilities and sales.

Contract Drilling Operations — Our drilling services are supported by several administrative offices and yard facilities located throughout our areas of operations including:

- Texas,
- New Mexico,
- Oklahoma,
- Colorado,

- Utah,
- Wyoming, and
- Western Canada.

Pressure Pumping — Our pressure pumping services are supported by several offices and yard facilities located throughout our areas of operations including:

- Pennsylvania,
- Ohio,
- West Virginia,
- Kentucky,
- Tennessee,
- Wyoming,
- Colorado, and
- New York.

Drilling and Completion Fluids — Our drilling and completion fluids services are supported by several administrative offices and stockpoint facilities located throughout our areas of operations including:

- Texas,
- Louisiana,
- New Mexico, and
- Oklahoma.

Oil and Natural Gas — Our oil and natural gas operations are supported by administrative and field offices in Texas.

We own our headquarters in Snyder, Texas, as well as several of our other facilities. We also lease a number of facilities and we do not believe that any one of the leased facilities is individually material to our operations. We believe that our existing facilities are suitable and adequate to meet our needs.

Item 3. *Legal Proceedings.*

In December 2005, two purported derivative actions were filed in Texas state court in Scurry County, Texas and in May 2006, a derivative action was filed in federal court in Lubbock, Texas, in each case against our directors, alleging that the directors breached their fiduciary duties to us as a result of alleged failure to timely discover the embezzlement of approximately $77.5 million by our former CFO, Jonathan D. Nelson. The Board of Directors formed a special litigation committee to review and inquire about these allegations and recommend our response, if any. Further legal proceedings in these suits were stayed pending completion of the work of the special litigation committee. The lawsuits sought recovery on behalf of and for us and did not seek recovery from us. In November 2006, the parties to all three of the derivative actions reached an agreement to settle the actions. After a preliminary hearing and notice to our stockholders, the state court held a hearing, approved the settlement, which requires the implementation of certain corporate governance measures, and signed a final judgment on December 29, 2006. As contemplated by the settlement agreement, the federal court entered a final judgment on January 10, 2007. Pursuant to the terms of the settlement, we will pay a net amount of $230,000 to the attorneys for the plaintiffs in the suits.

We are party to various other legal proceedings arising in the normal course of our business. We do not believe that the outcome of these proceedings, either individually or in the aggregate, will have a material adverse effect on our financial condition.

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

None.

PART II

Item 5. *Market for Registrant's Common Equity and Related Stockholder Matters and Issuer Purchases of Equity Securities.*

(a) Market Information

Our common stock, par value $0.01 per share, is publicly traded on the Nasdaq National Market and is quoted under the symbol "PTEN." Our common stock is included in the S&P MidCap 400 Index and several other market indexes. The following table provides high and low sales prices of our common stock for the periods indicated:

	High	Low
2006:		
First quarter	$38.49	$25.61
Second quarter	35.65	25.24
Third quarter	29.11	21.84
Fourth quarter	28.21	20.81
2005:		
First quarter	$26.66	$17.15
Second quarter	29.33	22.38
Third quarter	36.79	27.79
Fourth quarter	36.73	28.45

(b) Holders

As of February 21, 2007, there were approximately 2,200 holders of record and approximately 79,500 beneficial holders of our common stock.

(c) Dividends and Buyback Program

On April 28, 2004, our Board of Directors authorized a two-for-one stock split in the form of a stock dividend which was distributed on June 30, 2004. At June 30, 2004, an adjustment was made to reclassify an amount from retained earnings to common stock to account for the par value of the common stock issued as a stock dividend. This adjustment had no overall effect on equity. All historical share and per-share information prior to June 30, 2004 has been restated to reflect the impact of the two-for-one stock split.

On April 28, 2004, our Board of Directors approved the initiation of a quarterly cash dividend of $0.02 on each share of our common stock which was paid on June 2, 2004, September 1, 2004 and December 1, 2004. Total dividends paid in 2004 were approximately $10 million. In February 2005, our Board of Directors approved an increase in the quarterly cash dividend on our common stock to $0.04 per share from $0.02 per share. Quarterly cash dividends in the amount of $0.04 per share were paid on March 4, 2005, June 1, 2005, September 1, 2005 and December 1, 2005. Total cash dividends in 2005 were approximately $27.3 million. On March 2, 2006, our Board of Directors approved a cash dividend on our common stock in the amount of $0.04 per share which was paid on March 30, 2006. On April 26, 2006, our Board of Directors approved an increase in our quarterly cash dividend from $0.04 to $0.08 on each outstanding share of our common stock. Cash dividends of $0.08 per share were paid on June 30, 2006, September 29, 2006 and December 29, 2006. Total cash dividends in 2006 were approximately $45.8 million. The amount and timing of all future dividend payments is subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial condition, terms of our credit facilities and other factors.

The table below sets forth the information with respect to purchases of our common stock made by us during the quarter ended December 31, 2006.

Period covered	Total number of shares purchased(1)	Average price paid per share	Total number of shares (or units) purchased as part of publicly announced plans or programs(2)	Approximate dollar value of shares that may yet be purchased under the plans or programs(2)
October 1–31, 2006	1,025,000	$22.20	1,025,000	$60,572,000
November 1–30, 2006	2,378,542	$25.47	2,378,542	$ —
December 1–31, 2006	—	$ —	—	$ —
Total	3,403,542	$24.48	3,403,542	$ —

(1) All of the reported shares were purchased in open-market transactions.

(2) On June 7, 2004, our Board of Directors authorized a stock buyback program for the purchase of up to $30 million of our outstanding common stock. During 2004, we purchased 100,000 shares of our common stock in the open market for approximately $1.5 million. During 2005, we purchased 355,000 shares of our common stock in the open market for approximately $12.2 million. On March 27, 2006, our Board of Directors increased the previously authorized stock buyback program to allow for future purchases of up to $200 million of our outstanding common stock. During the second quarter of 2006, we completed the authorized buyback with the purchase of 6,704,800 shares of our common stock at a cost of approximately $200 million. On August 2, 2006, our Board of Directors again increased the previously authorized stock buyback program to allow for future purchases of up to $250 million of our outstanding common stock. During the remainder of 2006, we purchased an additional 9,940,542 shares of our common stock at a cost of approximately $250 million. Shares purchased under the stock buyback program during 2006 totaled $450 million and have been accounted for as treasury stock.

(d) Securities Authorized for Issuance Under Equity Compensation Plans

Equity compensation to our employees, officers and directors as of December 31, 2006 follows:

	Equity Compensation Plan Information		
Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted- Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans (Excluding Securities Reflected in Column(a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders(1)	5,812,537	$17.02	4,140,197
Equity compensation plans not approved by security holders(2)	762,559	$ 9.84	—
Total	6,575,096	$16.18	4,140,197

(1) The Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (the "2005 Plan") provides for awards of incentive stock options, non-incentive stock options, tandem and freestanding stock appreciation rights, restricted stock awards, other stock unit awards, performance share awards, performance unit awards and dividend equivalents to key employees, officers and directors, which are subject to certain vesting and forfeiture provisions. All options are granted with an exercise price equal to or greater than the fair market value of the

common stock at the time of grant. The vesting schedule and term are set by the Compensation Committee of the Board of Directors. All securities remaining available for future issuance under equity compensation plans approved by security holders in column (c) are available under this plan.

(2) The Amended and Restated Patterson-UTI Energy, Inc. 2001 Long-Term Incentive Plan (the "2001 Plan") was approved by the Board of Directors in July 2001. In connection with the approval of the 2005 Plan, the Board of Directors approved a resolution that no further options, restricted stock or other awards would be granted under any equity compensation plan, other than the 2005 Plan. The terms of the 2001 Plan provided for grants of stock options, stock appreciation rights, shares of restricted stock and performance awards to eligible employees other than officers and directors. No Incentive Stock Options could be awarded under the Plan. All options were granted with an exercise price equal to or greater than the fair market value of the common stock at the time of grant. The vesting schedule and term were set by the Compensation Committee of the Board of Directors.

Item 6. *Selected Financial Data.*

Our selected consolidated financial data as of December 31, 2006, 2005, 2004, 2003 and 2002, and for each of the five years then ended should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and related Notes thereto, included as Items 7 and 8, respectively, of this Report. Certain reclassifications have been made to the historical financial data to conform with the 2006 presentation.

	Years Ended December 31,				
	2006	2005	2004	2003	2002
	(In thousands, except per share amounts)				
Income Statement Data:					
Operating revenues:					
Contract drilling	$2,169,370	$1,485,684	$ 809,691	$ 639,694	$410,295
Pressure pumping	145,671	93,144	66,654	46,083	32,996
Drilling and completion fluids	192,358	122,011	90,557	69,230	69,943
Oil and natural gas	39,187	39,616	33,867	21,163	14,723
Total	2,546,586	1,740,455	1,000,769	776,170	527,957
Operating costs and expenses:					
Contract drilling	1,002,001	776,313	556,869	475,224	318,201
Pressure pumping	77,755	54,956	37,561	26,184	19,802
Drilling and completion fluids	150,372	98,530	76,503	61,424	60,762
Oil and natural gas	13,374	9,566	7,978	4,808	3,956
Depreciation, depletion, amortization and impairment	196,370	156,393	122,800	100,834	92,778
Selling, general and administrative	55,065	39,110	31,983	27,685	26,116
Embezzlement costs, net of recoveries	3,081	20,043	19,122	17,849	8,574
Other operating expenses	9,404	4,248	(514)	(4,120)	4,660
Total	1,507,422	1,159,159	852,302	709,888	534,849
Operating income (loss)	1,039,164	581,296	148,467	66,282	(6,892)
Other income	4,670	3,463	680	2,694	803
Income (loss) before income taxes and cumulative effect of change in accounting principle	1,043,834	584,759	149,147	68,976	(6,089)
Income tax expense (benefit)	371,267	212,019	54,801	25,320	(1,949)
Income (loss) before cumulative effect of change in accounting principle	672,567	372,740	94,346	43,656	(4,140)
Cumulative effect of change in accounting principle, net of related income tax expense of $398 in 2006 and benefit of $287 in 2003	687	—	—	(469)	—
Net income (loss)	$ 673,254	$ 372,740	$ 94,346	$ 43,187	$ (4,140)
Net income (loss) per common share:					
Basic:					
Income (loss) before cumulative effect of change in accounting principle	$ 4.07	$ 2.19	$ 0.57	$ 0.27	$ (0.03)
Cumulative effect of change in accounting principle	$ —	$ —	$ —	$ —	$ —
Net income (loss)	$ 4.08	$ 2.19	$ 0.57	$ 0.27	$ (0.03)

	Years Ended December 31,				
	2006	2005	2004	2003	2002
	(In thousands, except per share amounts)				
Diluted:					
Income (loss) before cumulative effect of change in accounting principle	$ 4.02	$ 2.15	$ 0.56	$ 0.27	$ (0.03)
Cumulative effect of change in accounting principle	$ —	$ —	$ —	$ —	$ —
Net income (loss)	$ 4.02	$ 2.15	$ 0.56	$ 0.26	$ (0.03)
Cash dividends per common share	$ 0.28	$ 0.16	$ 0.06	$ —	$ —
Weighted average number of common shares outstanding:					
Basic	165,159	170,426	166,258	161,272	157,410
Diluted	167,413	173,767	169,211	164,572	157,410
Balance Sheet Data:					
Total assets	$2,192,503	$1,795,781	$1,256,785	$1,039,521	$919,374
Borrowings under line of credit	120,000	—	—	—	—
Stockholders' equity	1,562,466	1,367,011	961,501	789,814	724,248
Working capital	335,052	382,448	235,480	198,399	166,885

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

This Item 7 contains forward-looking statements, which are made pursuant to the "Safe Harbor" provisions of the Private Securities Litigation Reform Act of 1995.

Management Overview — We are a leading provider of contract services to the North American oil and natural gas industry. Our services primarily involve the drilling, on a contract basis, of land-based oil and natural gas wells and to a lesser extent, we provide pressure pumping services and drilling and completion fluid services. In addition to the aforementioned contract services, we also engage in the development, exploration, acquisition and production of oil and natural gas. For the three years ended December 31, 2006, our operating revenues consisted of the following (dollars in thousands):

	2006		2005		2004	
Contract drilling	$2,169,370	84%	$1,485,684	86%	$ 809,691	81%
Pressure pumping	145,671	6	93,144	5	66,654	7
Drilling and completion fluids	192,358	8	122,011	7	90,557	9
Oil and natural gas	39,187	2	39,616	2	33,867	3
	$2,546,586	100%	$1,740,455	100%	$1,000,769	100%

We provide our contract services to oil and natural gas operators in many of the oil and natural gas producing regions of North America. Our contract drilling operations are focused in various regions of Texas, New Mexico, Oklahoma, Arkansas, Louisiana, Mississippi, Colorado, Utah, Wyoming, Montana, North Dakota, South Dakota and Western Canada, while our pressure pumping services are focused primarily in the Appalachian Basin. Our drilling and completion fluids services are provided to operators offshore in the Gulf of Mexico and on land in Texas, Southeastern New Mexico, Oklahoma and the Gulf Coast region of Louisiana. Our oil and natural gas operations are primarily focused in West and South Texas, Southeastern New Mexico, Utah and Mississippi.

The profitability of our business is most readily assessed by two primary indicators in our contract drilling segment: our average number of rigs operating and our average revenue per operating day. During 2006, our average number of rigs operating increased to 296 from 276 in 2005 and our average revenue per operating day increased to $20,050 from $14,770 in 2005. Primarily due to these improvements, we experienced an increase of approximately $301 million, or 81%, in consolidated net income in 2006.

Our revenues, profitability and cash flows are highly dependent upon the market prices of oil and natural gas. During periods of improved commodity prices, the capital spending budgets of oil and natural gas operators tend to expand, which results in increased demand for our contract services. Conversely, in periods of time when these commodity prices deteriorate, the demand for our contract services generally weakens and we experience downward pressure on pricing for our services.

We believe that the liquidity shown on our balance sheet as of December 31, 2006, which includes approximately $335 million in working capital (including $13.4 million in cash) and $195 million available under a $375 million line of credit ($120 million in borrowings are outstanding at December 31, 2006 and availability of $60 million is reserved for outstanding letters of credit) provides us with the ability to pursue acquisition opportunities, expand into new regions, make improvements to our assets, pay cash dividends and survive downturns in our industry.

Commitments and Contingencies — We maintain letters of credit in the aggregate amount of approximately $60 million for the benefit of various insurance companies as collateral for retrospective premiums and retained losses which could become payable under the terms of the underlying insurance contracts. These letters of credit expire at various times during each calendar year. No amounts have been drawn under the letters of credit.

As of December 31, 2006, we have remaining non-cancelable commitments to purchase approximately $297 million of equipment to be received throughout 2007.

In November 2005, we discovered that our former Chief Financial Officer, Jonathan D. Nelson ("Nelson"), had fraudulently diverted approximately $77.5 million of our funds for his own benefit. As a result, the Audit Committee of the Board of Directors commenced an investigation into Nelson's activities and retained independent counsel and independent forensic accountants to assist with the investigation. Nelson has been sentenced and is serving a term of imprisonment arising out of his embezzlement. A receiver has been appointed to take control of and liquidate the assets of Nelson in connection with his embezzlement of our funds. The receiver is in the process of seeking court approval for a plan of distribution of the assets recovered by the receiver and the proceeds thereof, which total approximately $40 million. While we believe we have a claim for at least the full amount of funds embezzled from us, other creditors have asserted or may assert claims with respect to the assets held by the receiver.

In December 2005, two purported derivative actions were filed in Texas state court in Scurry County, Texas and in May 2006, a derivative action was filed in federal court in Lubbock, Texas, in each case against our directors, alleging that the directors breached their fiduciary duties to us as a result of alleged failure to timely discover the embezzlement of approximately $77.5 million by our former CFO, Jonathan D. Nelson. The Board of Directors formed a special litigation committee to review and inquire about these allegations and recommend our response, if any. Further legal proceedings in these suits were stayed pending completion of the work of the special litigation committee. The lawsuits sought recovery on behalf of and for us and did not seek recovery from us. In November 2006, the parties to all three of the derivative actions reached an agreement to settle the actions. After a preliminary hearing and notice to our stockholders, the state court held a hearing, approved the settlement, which requires the implementation of certain corporate governance measures, and signed a final judgment on December 29, 2006. As contemplated by the settlement agreement, the federal court entered a final judgment on January 10, 2007. Pursuant to the terms of the settlement, we will pay a net amount of $230,000 to the attorneys for the plaintiffs in the suits.

Trading and investing — We have not engaged in trading activities that include high-risk securities, such as derivatives and non-exchange traded contracts. We invest cash primarily in highly liquid, short-term investments such as overnight deposits, money markets and highly rated municipal and commercial bonds.

Description of business — We conduct our contract drilling operations in Texas, New Mexico, Oklahoma, Arkansas, Louisiana, Mississippi, Colorado, Utah, Wyoming, Montana, North Dakota, South Dakota and Western Canada. As of December 31, 2006, we had 336 currently marketable land-based drilling rigs. We provide pressure pumping services to oil and natural gas operators primarily in the Appalachian Basin. These services consist primarily of well stimulation and cementing for completion of new wells and remedial work on existing wells. We provide drilling fluids, completion fluids and related services to oil and natural gas operators offshore in the Gulf of Mexico and on land in Texas, Southeastern New Mexico, Oklahoma and the Gulf Coast region of Louisiana. Drilling and completion fluids are used by oil and natural gas operators during the drilling process to control pressure when drilling oil and natural gas wells. We are also engaged in the development, exploration, acquisition and production of oil and natural gas. Our oil and natural gas operations are focused primarily in producing regions in West and South Texas, Southeastern New Mexico, Utah and Mississippi.

Critical Accounting Policies

In addition to established accounting policies, our consolidated financial statements are impacted by certain estimates and assumptions made by management. The following is a discussion of our critical accounting policies pertaining to property and equipment, oil and natural gas properties, goodwill, revenue recognition and the use of estimates.

Property and equipment — Property and equipment, including betterments which extend the useful life of the asset, are stated at cost. Maintenance and repairs are charged to expense when incurred. We provide for the depreciation of our property and equipment using the straight-line method over the estimated useful lives. Our method of depreciation does not change when equipment becomes idle; we continue to depreciate idled equipment on a straight-line basis. No provision for salvage value is considered in determining depreciation of our property and equipment. We review our assets for impairment when events or changes in circumstances indicate that the carrying values of certain assets either exceed their respective fair values or may not be recovered over their estimated remaining useful lives. The cyclical nature of our industry has resulted in fluctuations in rig utilization over periods of time. Management believes that the contract drilling industry will continue to be cyclical and rig utilization will fluctuate. Based on management's expectations of future trends, we estimate future cash flows over the life of the respective assets in our assessment of impairment. These estimates of cash flows are based on historical cyclical trends in the industry as well as management's expectations regarding the continuation of these trends in the future. Provisions for asset impairment are charged to income when estimated future cash flows, on an undiscounted basis, are less than the asset's net book value. Impairment charges are recorded based on discounted cash flows. There were no impairment charges to property and equipment during the years 2006, 2005 or 2004.

Oil and natural gas properties — Oil and natural gas properties are accounted for using the successful efforts method of accounting. Under the successful efforts method of accounting, exploration costs which result in the discovery of oil and natural gas reserves and all development costs are capitalized to the appropriate well. Exploration costs which do not result in discovering oil and natural gas reserves are charged to expense when such determination is made. In accordance with Statement of Financial Accounting Standards No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies," ("SFAS No. 19") costs of exploratory wells are initially capitalized to wells in progress until the outcome of the drilling is known. We review wells in progress quarterly to determine whether sufficient progress is being made in assessing the reserves and the economic operating viability of the respective projects. If no progress has been made in assessing the reserves and the economic operating viability of a project after one year following the completion of drilling, we consider the costs of the well to be impaired and recognize the costs as expense. Geological and geophysical costs, including seismic costs and costs to carry and retain undeveloped properties, are charged to expense when incurred. The capitalized costs of both developmental and successful exploratory type wells, consisting of lease and well equipment, lease acquisition costs and intangible development costs, are depreciated, depleted and amortized on the units-of-production method, based on engineering estimates of proved oil and natural gas reserves of each respective field. We review our proved oil and natural gas properties for impairment when an event occurs such as downward revisions in reserve estimates or decreases in oil and natural gas prices. Proved properties are grouped by field and undiscounted cash flow estimates are prepared internally and reviewed by an independent petroleum engineer. If the net book value of a field exceeds its undiscounted cash flow estimate, impairment expense is measured and recognized as the difference between its net book value and discounted cash flow. Unproved oil and natural gas properties are reviewed quarterly to determine impairment. Our intent to drill, lease expiration and abandonment of area are considered. Assessment of impairment is made on a lease-by-lease basis. If an unproved property is determined to be impaired, then costs related to that property are expensed. Impairment expense of approximately $5.0 million, $4.4 million and $3.2 million for the years ended December 31, 2006, 2005 and 2004, respectively, is included in depreciation, depletion and impairment in the accompanying financial statements.

Goodwill — Goodwill is considered to have an indefinite useful economic life and is not amortized. As such, we assess impairment of our goodwill annually or on an interim basis if events or circumstances indicate that the fair value of the asset has decreased below its carrying value.

Revenue recognition — Revenues are recognized when services are performed, except for revenues earned under turnkey contract drilling arrangements which are recognized using the completed contract method of accounting, as described below. We follow the percentage-of-completion method of accounting for footage contract drilling arrangements. Under the percentage-of-completion method, management estimates are relied upon in the determination of the total estimated expenses to be incurred drilling the well. Due to the nature of turnkey contract drilling arrangements and risks therein, we follow the completed contract method of accounting for such arrangements. Under this method, revenues and expenses related to a well in progress are deferred and recognized in the period the well is completed. Provisions for losses on incomplete or in-process wells are made when estimated total expenses are expected to exceed estimated total revenues. We recognize reimbursements received from third parties for out-of-pocket expenses incurred as revenues and account for out-of-pocket expenses as direct costs.

Use of estimates — The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make certain estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from such estimates.

Key estimates used by management include:

- allowance for doubtful accounts,
- total expenses to be incurred on footage and turnkey drilling contracts,
- depreciation and depletion,
- asset impairment,
- reserves for self-insured levels of insurance coverages, and
- fair values of assets and liabilities assumed in acquisitions.

For additional information on our accounting policies, see Note 1 of Notes to Consolidated Financial Statements included as a part of Item 8 of this Report.

Related Party Transactions

We operate certain oil and natural gas properties in which certain of our affiliated persons have participated, either individually or through entities they control. These participations have typically been through working interests in prospects or properties we originated or acquired. At December 31, 2006, affiliated persons were working interest owners in 281 of 330 total wells we operated. We make sales of working interests to reduce our economic risk in the properties. Generally, it is more efficient for us to sell the working interests to these affiliated persons than to market them to unrelated third parties. Sales of working interests to affiliated parties were made at cost, comprised of our costs of acquiring and preparing the working interests for sale plus a promote fee in some cases. These costs were paid by the working interest owners on a pro rata basis based upon their working interest ownership percentage. The price at which working interests were sold to affiliated persons was the same price as that at which working interests were sold to unaffiliated persons, except that in some cases the affiliated persons also paid a promote fee.

Production revenues and joint interest costs of each of the affiliated persons during 2006 for all wells operated by us in which the affiliated persons have working interests are presented in the table below. These amounts do not necessarily represent their profits or losses from these interests because the joint interest costs do not include the parties' related drilling and leasehold acquisition costs incurred prior to January 1, 2006. These activities resulted in a payable to the affiliated persons of approximately $1.5 million and $1.5 million and a receivable from the affiliated persons of approximately $1.6 million and $1.2 million at December 31, 2006 and 2005, respectively.

	Year Ended December 31, 2006	
Name	Production Revenues(1)	Joint Interest Costs(2)
Cloyce A. Talbott	$ 301,445	$ 95,074
Jana Talbott, Executrix to the Estate of Steve Talbott(3)	20,621	5,513
Stan Talbott(3)	8,597	4,043
John Evan Talbott Trust(3)	3,825	875
Lisa Beck and Stacy Talbott(3)	1,311,651	893,903
SSI Oil & Gas, Inc.(4)	225,360	181,970
IDC Enterprises, Ltd.(5)	13,741,205	12,829,963
Subtotal	15,612,704	14,011,341
A. Glenn Patterson(6)	125,390	40,104
Robert Patterson(6)	9,071	4,904
Thomas M. Patterson(6)	9,071	4,904
Subtotal	143,532	49,912
Total	$15,756,236	$14,061,253

(1) Revenues for production of oil and natural gas, net of state severance taxes.

(2) Includes leasehold costs, tangible equipment costs, intangible drilling costs and lease operating expense billed during that period. All joint interest costs have been paid on a timely basis.

(3) Stan Talbott, Lisa Beck and Stacy Talbott are Mr. Talbott's adult children. Steve Talbott is the deceased son of Mr. Talbott. John Evan Talbott is Mr. Talbott's grandson.

(4) SSI Oil & Gas, Inc. is beneficially owned 50% by Cloyce A. Talbott and directly owned 50% by A. Glenn Patterson.

(5) IDC Enterprises, Ltd. is 50% owned by Cloyce A. Talbott and 50% owned by A. Glenn Patterson.

(6) Through April 2006, A. Glenn Patterson was our President and Chief Operating Officer. Robert and Thomas M. Patterson are A. Glenn Patterson's adult children.

Liquidity and Capital Resources

As of December 31, 2006, we had working capital of $335 million including cash and cash equivalents of $13 million. For 2006, our sources of cash flow included:

- $837 million from operating activities,
- $120 million in net proceeds from borrowings under our line of credit,
- $11 million in proceeds from the disposal of property and equipment, and
- $3 million from the exercise of stock options and related tax benefits.

We used $450 million to purchase shares of our common stock in the open market, $46 million to pay dividends on our common stock, and $598 million:

- to make capital expenditures for the betterment and refurbishment of our drilling rigs,
- to acquire and procure drilling equipment and facilities to support our drilling operations,
- to fund capital expenditures for our pressure pumping and drilling and completion fluids divisions, and
- to fund leasehold acquisition and exploration and development of oil and natural gas properties.

On August 2, 2006, we entered into an agreement to amend our $200 million unsecured revolving line of credit ("LOC"). In connection with this amendment, the borrowing capacity under this LOC was increased to $375 million. No significant changes were made to the terms of the LOC, including the interest to be paid on outstanding balances and financial covenants. As of December 31, 2006, we had borrowed $120 million under the LOC and $60 million in letters of credit were outstanding. As a result, we had available borrowing capacity of $195 million at December 31, 2006.

On March 2, 2006, our Board of Directors approved a cash dividend on our common stock in the amount of $0.04 per share. The dividend of approximately $6.9 million was paid on March 30, 2006. On April 26, 2006, our Board of Directors approved an increase in our quarterly cash dividend from $0.04 to $0.08 on each outstanding share of our common stock. This dividend of approximately $13.4 million was paid on June 30, 2006 to holders of record on June 15, 2006. On August 2, 2006, our Board of Directors approved a quarterly cash dividend of $0.08 on each outstanding share of our common stock. This dividend of approximately $13.0 million was paid on September 29, 2006 to holders of record as of September 14, 2006. On October 31, 2006, our Board of Directors approved a quarterly cash dividend of $0.08 on each outstanding share of our common stock. This dividend of approximately $12.5 million was paid on December 29, 2006 to holders of record as of December 14, 2006. The amount and timing of all future dividend payments is subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial condition, terms of our credit facilities and other factors.

On March 27, 2006, our Board of Directors increased our previously authorized stock buyback program to allow for future purchases of up to $200 million of our outstanding common stock. During the second quarter of 2006, we completed the authorized buyback with the purchase of 6,704,800 shares of our common stock at a cost of approximately $200 million. On August 2, 2006, our Board of Directors again increased the previously authorized stock buyback program to allow for future purchases of up to $250 million of our outstanding common stock. During the remainder of 2006, we purchased an additional 9,940,542 shares of our common stock at a cost of approximately $250 million. Shares purchased under the stock buyback program have been accounted for as treasury stock.

We believe that the current level of cash and short-term investments, together with cash generated from operations, should be sufficient to meet our capital needs. From time to time, acquisition opportunities are evaluated. The timing, size or success of any acquisition and the associated capital commitments are unpredictable. Should opportunities for growth requiring capital arise, we believe we would be able to satisfy these needs through a combination of working capital, cash generated from operations, our existing credit facility and additional debt or equity financing. However, there can be no assurance that such capital would be available.

Contractual Obligations

The following table presents information with respect to our contractual obligations as of December 31, 2006 (dollars in thousands):

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Borrowings under line of credit(1)	$120,000	$ —	$120,000	$ —	$ —
Commitments to purchase equipment(2)	296,577	296,577	—	—	—
	$416,577	$296,577	$120,000	$ —	$ —

(1) Our line of credit is a revolving line of credit that matures on December 16, 2009. So long as we are in compliance with our obligations under the credit agreement, no principal repayments are required until maturity.

(2) Represents non-cancelable commitments to purchase equipment to be delivered throughout 2007.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements at December 31, 2006.

Results of Operations

Comparison of the years ended December 31, 2006 and 2005

A summary of operations by business segment for the years ended December 31, 2006 and 2005 follows:

Contract Drilling	Year Ended December 31, 2006	2005	% Change
	(Dollars in thousands)		
Revenues	$2,169,370	$1,485,684	46.0%
Direct operating costs	$1,002,001	$ 776,313	29.1%
Selling, general and administrative	$ 7,313	$ 5,069	44.3%
Depreciation	$ 168,607	$ 131,740	28.0%
Operating income	$ 991,449	$ 572,562	73.2%
Operating days	108,192	100,591	7.6%
Average revenue per operating day	$ 20.05	$ 14.77	35.7%
Average direct operating costs per operating day	$ 9.26	$ 7.72	19.9%
Number of rigs operated	331	307	7.8%
Average rigs operating	296	276	7.2%
Capital expenditures	$ 531,087	$ 329,073	61.4%

Our average number of rigs operating increased to 296 in 2006 from 276 in 2005. The average market price of natural gas and our average rigs operating for each of the fiscal quarters and full years in 2006 and 2005 follow:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year
2006:					
Average natural gas price(1)	$7.93	$6.74	$6.26	$ 6.87	$6.94
Average rigs operating	300	295	301	290	296
2005:					
Average natural gas price(1)	$6.62	$7.14	$9.82	$12.64	$8.98
Average rigs operating	263	265	283	292	276

(1) The average natural gas price above represents the Henry Hub Spot price as reported by the United States Energy Information Administration.

Revenues and direct operating costs increased as a result of the increased number of operating days, as well as an increase in the average revenue and average direct operating costs per operating day. Operating days and average rigs operating increased as a result of increased demand for our contract drilling services and the increase in the number of marketable rigs in our fleet due to our rig activation program. Average revenue per operating day increased as a result of increased demand and pricing for our drilling services. Average direct operating costs per operating day increased primarily as a result of increased compensation costs and an increase in the cost of maintenance for our rigs. Significant capital expenditures have been incurred to activate additional drilling rigs, to modify and upgrade our drilling rigs and to acquire additional related equipment such as drill pipe, drill collars, engines, fluid circulating systems, rig hoisting systems and safety enhancement equipment. The increase in depreciation expense was a result of the capital expenditures discussed above.

	Year Ended December 31,		
Pressure Pumping	**2006**	**2005**	**% Change**
	(Dollars in thousands)		
Revenues	$145,671	$93,144	56.4%
Direct operating costs	$ 77,755	$54,956	41.5%
Selling, general and administrative	$ 13,185	$ 9,430	39.8%
Depreciation	$ 9,896	$ 7,094	39.5%
Operating income	$ 44,835	$21,664	107.0%
Total jobs	11,650	9,615	21.2%
Average revenue per job	$ 12.50	$ 9.69	29.0%
Average direct operating costs per job	$ 6.67	$ 5.72	16.6%
Capital expenditures	$ 41,262	$25,508	61.8%

Revenues and direct operating costs increased as a result of the increased number of jobs, as well as an increase in the average revenue and average direct operating cost per job. The increase in jobs was attributable to increased demand for our services and increased operating capacity which has been added. Increased average revenue per job was due to increased pricing for our services and an increase in the number of larger jobs. Average direct operating costs per job increased as a result of increases in compensation and the cost of materials used in our operations as well as an increase in the number of larger jobs. Selling, general and administrative expense increased as a result of additional expenses to support the expanded operations of the pressure pumping segment. Significant capital expenditures have been incurred to add capacity and modify and upgrade existing equipment. The increase in depreciation expense was a result of the capital expenditures discussed above.

	Year Ended December 31,		
Drilling and Completion Fluids	**2006**	**2005**	**% Change**
	(Dollars in thousands)		
Revenues	$192,358	$122,011	57.7%
Direct operating costs	$150,372	$ 98,530	52.6%
Selling, general and administrative	$ 10,521	$ 8,912	18.1%
Depreciation	$ 2,706	$ 2,368	14.3%
Operating income	$ 28,759	$ 12,201	135.7%
Total jobs	2,042	1,980	3.1%
Average revenue per job	$ 94.20	$ 61.62	52.9%
Average direct operating costs per job	$ 73.64	$ 49.76	48.0%
Capital expenditures	$ 4,222	$ 3,042	38.8%

Revenues and direct operating costs increased primarily as a result of increases in the average revenue and direct operating costs per job. Average revenue and direct operating costs per job increased primarily as a result of an increase in large jobs in the Gulf of Mexico.

Oil and Natural Gas Production and Exploration	Year Ended December 31, 2006	2005	% Change
	(Dollars in thousands, except commodity prices)		
Revenues	$39,187	$39,616	(1.1)%
Direct operating costs	$13,374	$ 9,566	39.8%
Selling, general and administrative	$ 2,785	$ 2,189	27.2%
Depreciation, depletion and impairment	$14,368	$14,456	(0.6)%
Operating income	$ 8,660	$13,405	(35.4)%
Capital expenditures	$21,198	$17,163	23.5%
Average net daily oil production (Bbls)	983	860	14.3%
Average net daily gas production (Mcf)	5,143	7,016	(26.7)%
Average oil sales price (per Bbl)	$ 63.83	$ 54.30	17.6%
Average gas sales price (per Mcf)	$ 6.82	$ 7.64	(10.7)%

Direct operating costs increased primarily due to $4.2 million in costs associated with the abandonment of exploratory wells. Depreciation, depletion and impairment expense includes $5.0 million and $4.4 million incurred during 2006 and 2005, respectively, to reflect the impairment of certain oil and natural gas properties. Average net daily oil production increased due to the completion of new wells in 2006. Average net daily natural gas production decreased as a result of production declines and the sale of certain natural gas properties.

Corporate and Other	Year Ended December 31, 2006	2005	% Change
	(Dollars in thousands)		
Selling, general and administrative	$21,261	$13,510	57.4%
Depreciation	$ 793	$ 735	7.9%
Other operating expenses	$ 9,404	$ 4,248	121.4%
Embezzlement costs, net of recoveries	$ 3,081	$20,043	(84.6)%
Interest income	$ 5,925	$ 3,551	66.9%
Interest expense	$ 1,602	$ 516	210.5%
Other income	$ 347	$ 428	(18.9)%
Capital expenditures	$ 150	$ 5,308	(97.2)%

Selling, general and administrative expense increased primarily as a result of an increase of $7.8 million in stock-based compensation expense which was impacted by the adoption of a new accounting standard in 2006 requiring the expensing of stock options. Other operating expenses include bad debt expense of $5.4 million and $1.2 million in 2006 and 2005, respectively. Embezzlement costs, net of recoveries in 2005 includes payments made to or for the benefit of Jonathan D. Nelson, our former CFO, for assets and services that were not received by the Company and in 2006 includes continuing professional and other costs related to the embezzlement, net of insurance proceeds of $2.0 million received in connection with the loss. Interest expense in 2006 increased due to borrowings under our line of credit during 2006.

Comparison of the years ended December 31, 2005 and 2004

A summary of operations by business segment for the years ended December 31, 2005 and 2004 follows:

Contract Drilling	Year Ended December 31, 2005	2004	% Change
	(Dollars in thousands)		
Revenues	$1,485,684	$809,691	83.5%
Direct operating costs	$ 776,313	$556,869	39.4%
Selling, general and administrative	$ 5,069	$ 4,417	14.8%
Depreciation	$ 131,740	$101,779	29.4%
Operating income	$ 572,562	$146,626	290.5%
Operating days	100,591	77,355	30.0%
Average revenue per operating day	$ 14.77	$ 10.47	41.1%
Average direct operating costs per operating day	$ 7.72	$ 7.20	7.2%
Number of rigs operated	307	259	18.5%
Average rigs operating	276	211	30.8%
Capital expenditures	$ 329,073	$140,945	133.5%

Our average number of rigs operating increased to 276 in 2005 from 211 in 2004. The average market price of natural gas and our average rigs operating for each of the fiscal quarters and full years in 2005 and 2004 follow:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year
2005:					
Average natural gas price(1)	$6.62	$7.14	$9.82	$12.64	$8.98
Average rigs operating	263	265	283	292	276
2004:					
Average natural gas price(1)	$5.64	$6.13	$5.62	$ 6.42	$5.95
Average rigs operating	197	203	216	229	211

(1) The average natural gas price above represents the Henry Hub Spot price as reported by the United States Energy Information Administration.

Revenues and direct operating costs increased as a result of the increased number of operating days, as well as an increase in the average revenue and average direct operating costs per operating day. Operating days and average rigs operating increased as a result of the increased demand for our contract drilling services and the increase in the number of marketable rigs in our fleet due to the acquisition of land drilling assets from Key Energy Services, Inc. in January 2005 and our rig activation program. Average revenue per operating day increased as a result of increased demand and pricing for our drilling services. Significant capital expenditures were incurred during 2005 to activate additional drilling rigs to meet increased demand, to modify and upgrade our drilling rigs and to acquire additional related equipment such as drill pipe, drill collars, engines, fluid circulating systems, rig hoisting systems and safety enhancement equipment. The increase in depreciation expense was a result of the capital expenditures discussed above.

Pressure Pumping	Year Ended December 31,		
	2005	2004	% Change
	(Dollars in thousands)		
Revenues	$93,144	$66,654	39.7%
Direct operating costs	$54,956	$37,561	46.3%
Selling, general and administrative	$ 9,430	$ 7,234	30.4%
Depreciation	$ 7,094	$ 5,112	38.8%
Operating income	$21,664	$16,747	29.4%
Total jobs	9,615	7,444	29.2%
Average revenue per job	$ 9.69	$ 8.95	8.3%
Average direct operating costs per job	$ 5.72	$ 5.05	13.3%
Capital expenditures	$25,508	$17,705	44.1%

Revenues and direct operating costs increased as a result of the increased number of jobs, as well as an increase in the average revenue and average direct operating costs per job. The increase in jobs in 2005 was largely due to our expanded operations in the Appalachian regions of Kentucky, Tennessee and West Virginia, as well as increased demand for our services resulting from the improved industry conditions as discussed in "Contract Drilling" above. Increased average revenue per job was due primarily to increased pricing for our services. Selling, general and administrative expenses increased largely as a result of the expanding operations of the pressure pumping segment. Increased depreciation expense during 2005 was largely due to the expansion of the pressure pumping segment from 2003 through 2005 and related expenditures to acquire necessary equipment to facilitate the growth. Capital expenditures increased in 2005 compared to 2004 due to further expansion of services into Tennessee and Wyoming as well as modifications and upgrades to existing equipment and facilities.

Drilling and Completion Fluids	Year Ended December 31,		
	2005	2004	% Change
	(Dollars in thousands)		
Revenues	$122,011	$90,557	34.7%
Direct operating costs	$ 98,530	$76,503	28.8%
Selling, general and administrative	$ 8,912	$ 7,696	15.8%
Depreciation	$ 2,368	$ 2,156	9.8%
Operating income	$ 12,201	$ 4,202	190.4%
Total jobs	1,980	2,205	(10.2)%
Average revenue per job	$ 61.62	$ 41.07	50.0%
Average direct operating costs per job	$ 49.76	$ 34.70	43.4%
Capital expenditures	$ 3,042	$ 1,488	104.4%

Revenues and direct operating costs increased as a result of an increase in the average revenue and direct operating costs per job. Average revenue and direct operating costs per job increased primarily as a result of an increase in the size of our offshore jobs. Selling, general and administrative expense increased primarily due to increased incentive compensation resulting from higher profitability levels.

Oil and Natural Gas Production and Exploration	Year Ended December 31,		
	2005	2004	% Change
	(Dollars in thousands, except for commodity prices)}		
Revenues	$39,616	$33,867	17.0%
Direct operating costs	$ 9,566	$ 7,978	19.9%
Selling, general and administrative	$ 2,189	$ 1,816	20.5%
Depreciation, depletion and impairment	$14,456	$13,309	8.6%
Operating income	$13,405	$10,764	24.5%
Capital expenditures	$17,163	$14,451	18.8%
Average net daily oil production (Bbls)	860	1,071	(19.7)%
Average net daily gas production (Mcf)	7,016	7,429	(5.6)%
Average oil sales price (per Bbl)	$ 54.30	$ 39.12	38.8%
Average gas sales price (per Mcf)	$ 7.64	$ 5.81	31.5%

Revenues increased due to increased market prices for oil and natural gas. Direct operating costs increased as a result of higher oilfield service cost and production taxes. Average net daily oil production decreased as a result of production declines and the sale of certain oil properties during 2005. Average net daily gas production also decreased as a result of the sale of certain natural gas properties, however, this decrease was partially offset by an increase in production. Depreciation, depletion and impairment expense includes approximately $4.4 million and $3.2 million of expenses incurred during 2005 and 2004, respectively, to impair certain oil and gas properties.

Corporate and Other	Year Ended December 31,		
	2005	2004	% Change
	(Dollars in thousands)		
Selling, general and administrative	$13,510	$10,820	24.9%
Depreciation	$ 735	$ 444	65.5%
Other operating expenses	$ 4,248	$ (514)	N/A%
Embezzlement costs, net of recoveries	$20,043	$19,122	4.8%
Interest income	$ 3,551	$ 1,140	211.5%
Interest expense	$ 516	$ 695	(25.8)%
Other income	$ 428	$ 235	82.1%
Capital expenditures	$ 5,308	$ —	N/A%

Selling, general and administrative expenses increased primarily as a result of payroll taxes attributable to the exercise of employee stock options, increased professional fees and additional compensation expense related to the issuance of restricted shares to certain key employees in 2004 and 2005. Embezzlement costs, net of recoveries includes fraudulent payments made to or for the benefit of Jonathan D. Nelson, our former CFO, for assets and services that were not received by the Company and professional fees and expenses incurred as a result of the embezzlement. Other operating expenses in 2005 includes a charge of $4.2 million to increase reserves related to the financial failure of a workers' compensation insurance carrier used previously by the Company.

Income Taxes

	Year Ended December 31,		
	2006	2005	2004
	(Dollars in thousands)		
Income before income tax	$1,043,834	$584,759	$149,147
Income tax expense	371,267	212,019	54,801
Effective tax rate	35.6%	36.3%	36.7%

The effective tax rate in 2006 is a result of a Federal rate of 35.0% plus an effective state tax rate of 1.4% reduced by permanent differences between taxable income and book income ("permanent differences"). The effective tax rate in 2005 is a result of a Federal rate of 35.0% plus an effective state tax rate of 1.8% reduced by permanent differences. The effective tax rate in 2004 is a result of a Federal rate of 35.0% and an effective state income tax rate of 1.6% increased by permanent differences. The permanent differences to our effective income tax rate in 2006 and 2005 were largely attributable to the Domestic Production Activities Deduction. The deduction was enacted as part of the American Jobs Creation Act of 2004 effective for taxable years after December 31, 2004. The act allows a deduction of 3% in 2005 and 2006, 6% in 2007, 2008 and 2009, and 9% in 2010 and after on the lesser of qualified production activities income or taxable income.

For tax purposes, we have available at December 31, 2006, Federal net operating loss carryforwards of approximately $5 million and $118,000 of alternative minimum tax credit carryforwards. These carryforwards are attributable to the acquisition of TMBR in February 2004.

The net operating loss carryforwards, if unused, are scheduled to expire as follows: 2018 — $1 million and 2019 — $4 million. The alternative minimum tax credit may be carried forward indefinitely.

We record deferred Federal income taxes based primarily on the relationship between the amount of our unused Federal net operating loss carryforwards and the temporary differences between the book basis and tax basis in our assets. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the year in which those temporary differences are expected to be settled. As a result of fully recognizing the benefit of our deferred income taxes, we incur deferred income tax expense as these benefits are utilized. We incurred a deferred tax benefit of approximately $4.1 million in 2006 and a deferred income tax expense of approximately $17.1 million and $14.8 million for 2005 and 2004, respectively.

Volatility of Oil and Natural Gas Prices

Our revenue, profitability and rate of growth are substantially dependent upon prevailing prices for oil and natural gas, with respect to all of our operating segments. For many years, oil and natural gas prices and markets have been volatile. Prices are affected by market supply and demand factors as well as international military, political and economic conditions, and the ability of OPEC, to set and maintain production and price targets. All of these factors are beyond our control. The average market price of natural gas has improved from $3.36 in 2002 to $6.94 in 2006, resulting in an increase in demand for our drilling services. Our average number of rigs operating increased from 126 in 2002 to 296 in 2006. We expect oil and natural gas prices to continue to be volatile and to affect our financial condition and operations and ability to access sources of capital. A significant decrease in market prices for natural gas would likely result in a material decrease in demand for drilling rigs and reduction in our operation results.

The North American land drilling industry has experienced many downturns in demand over the last decade. During these periods, there have been substantially more drilling rigs available than necessary to meet demand. As a result, drilling contractors have had difficulty sustaining profit margins during the downturn periods.

Impact of Inflation

We believe that inflation will not have a significant near-term impact on our financial position.

Recently Issued Accounting Standards

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109* ("FIN 48"). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 is effective for fiscal years beginning after December 15, 2006 and became effective for the Company as of January 1, 2007. The implementation of this standard is not expected to have a material impact in 2007.

In September 2006, the FASB issued Statement No. 157, *Fair Value Measurements* ("FAS 157"). FAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurement. FAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. FAS 157 will be effective for the Company in the quarter ending March 31, 2008. The application of FAS 157 is not expected to have a material impact to the Company.

In September 2006, the SEC staff issued Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements* ("SAB 108"). SAB 108 was issued in order to eliminate the diversity of practice surrounding how public companies quantify financial statement misstatements. Traditionally, there have been two widely-recognized methods for quantifying the effects of financial statement misstatements. The "roll-over" method focuses primarily on the impact of a misstatement on the income statement (including the reversing effect of prior year misstatements) but its use can lead to the accumulation of misstatements in the balance sheet. The "iron-curtain" method, on the other hand, focuses primarily on the effect of correcting the period-end balance sheet with less emphasis on the reversing effects of prior year errors on the income statement. The Company currently uses the iron-curtain method for quantifying identified financial statement misstatements. In SAB 108, the SEC staff established an approach that requires quantification of financial statement misstatements based on the effects of the misstatements on each of the company's financial statements and the related financial statement disclosures. This model is commonly referred to as a "dual approach" because it requires quantification of errors under both the iron curtain and the roll-over methods. The Company applied the provisions of SAB 108 in the quarter ended December 31, 2006 and there was no impact.

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

We currently have exposure to interest rate market risk associated with borrowings under our credit facility. The revolving credit facility calls for periodic interest payments at a floating rate ranging from LIBOR plus 0.625% to 1.0% or at the prime rate. The applicable rate above LIBOR is based upon our debt to capitalization ratio. A 5% increase in LIBOR and the prime rate would result in additional interest expense of approximately $415,000 based on borrowings outstanding at December 31, 2006.

We conduct some business in Canadian dollars through our Canadian land-based drilling operations. The exchange rate between Canadian dollars and U.S. dollars has fluctuated during the last several years. If the value of the Canadian dollar against the U.S. dollar weakens, revenues and earnings of our Canadian operations will be reduced and the value of our Canadian net assets will decline when they are translated to U.S. dollars.

Item 8. *Financial Statements and Supplementary Data.*

Financial Statements are filed as a part of this Report at the end of Part IV hereof beginning at page F-1, Index to Consolidated Financial Statements, and are incorporated herein by this reference.

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

None.

Item 9A. *Controls and Procedures.*

Disclosure Controls and Procedures:

Under the supervision and with the participation of our management, including our Chief Executive Officer (CEO) and Chief Financial Officer (CFO), we conducted an evaluation of the effectiveness of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities and Exchange Act of 1934, as amended (the Exchange Act), as of the end of the period covered by this Annual Report on Form 10-K. Based on this evaluation, our CEO and CFO concluded that, as of December 31, 2006, our disclosure controls and procedures were effective to ensure that information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms and is accumulated and reported to our management, including our CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting:

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our CEO and CFO, we carried out an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2006, based on the *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, our management has concluded that our internal control over financial reporting was effective as of December 31, 2006.

Our assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears under Item 8 of this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting:

As of December 31, 2005, in our assessment of the effectiveness of our internal control over financial reporting, we identified material weaknesses in our internal control over financial reporting relating to:

1. *Control environment.* We did not maintain a control environment adequate to encourage the prevention or detection of the override of our controls or intentional misconduct, including misappropriation of assets and the preparation of false management reports, accounting records, financial statements and documents together with forged approval signatures. This control environment material weakness contributed to the embezzlement by our former Chief Financial Officer, Jonathan D. Nelson, of our funds for his own benefit, and in turn resulted in the restatement of our consolidated financial statements for the years ended December 31, 2004, 2003 and 2002, each of the quarters of 2004 and 2003, and the first three quarters of 2005.

2. *Controls over property and equipment.* We did not maintain effective controls over the completeness and accuracy of our accounting for property and equipment including (i) the timely and accurate depreciation of all property and equipment, (ii) the identification and recording of all property and equipment retirements when they occurred, and (iii) that property and equipment transferred between our locations was accurately and completely reflected in our accounting records. This control deficiency resulted in certain inaccuracies in our accounting for property and equipment and in the restatement of our consolidated financial statements for the years ended December 31, 2004, 2003 and 2002; each of the quarters of 2004 and 2003; and the first three quarters of 2005.

These material weaknesses are discussed in greater detail in our Annual Report on Form 10-K for the year ended December 31, 2005.

During the fourth quarter of 2006, we completed the implementation of the following remediation steps to address the material weakness in our control environment:

- employees provide formal certifications of information contained in SEC filings related to their areas of responsibility;
- senior employees and accounting staff submit annual written questionnaires with respect to awareness as to questionable business practices;
- educational and training programs covering ethics, compliance, financial reporting, good business practices and fraud awareness have been provided to employees;
- additional guidelines were provided to senior management with respect to their responsibilities for SEC filings, financial reports, budgets and maintenance of controls over assets and expenditures; and,
- annual reporting to the audit committee with respect to these processes and procedures was added.

Additionally, certain structural changes and processes and procedures were instituted to increase communications between the financial reporting and accounting functions and operations and between financial reporting and accounting functions and senior management. The internal audit reporting structure was also revised to provide for enhanced reporting to the audit committee.

During the fourth quarter of 2006, we completed the implementation of the following remediation steps to address the material weakness in our controls over property and equipment:

- increased coordination between accounting staff and operations to more promptly identify the impairment or retirement of drilling equipment undergoing refurbishment or repair;
- instituted quarterly physical inventories of our drill pipe and drill collars with comparison of the results of those inventories to our property records;
- instituted an annual physical inventory of significant drilling equipment with comparison of the results of that inventory to our property records; and,
- improved procedures to identify property placed in service and to begin depreciation of those assets when placed in service.

The changes described above are changes in our internal control over financial reporting during the most recently completed fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. *Other Information*

On February 20, 2007, the Compensation Committee of the Board of Directors of Patterson-UTI Energy, Inc. adopted a bonus compensation program (the "Program") that would allocate two-thirds of one percent of the Company's consolidated earnings before interest, income taxes and depreciation, depletion and amortization ("EBITDA") for fiscal 2007 (the "Allocated Bonus Amount") among the following four executive officers of the Company if the Company has EBITDA of at least $400 million for fiscal 2007:

- Mark S. Siegel (Chairman of the Board and Director);
- Cloyce A. Talbott (President & Chief Executive Officer and Director) (Messrs. Siegel and Talbott, collectively, the "Group A Executive Officers");
- Kenneth N. Berns (Senior Vice President and Director); and
- John E. Vollmer III (Senior Vice President — Corporate Development, Chief Financial Officer and Treasurer) (Messrs. Berns and Vollmer, collectively, the "Group B Executive Officers").

Each Group A Executive Officer would be allocated one-third of the Allocated Bonus Amount and each Group B Executive Officer would be allocated one-sixth of the Allocated Bonus Amount, however, the Compensation Committee expressly retained the ability to reduce the Allocated Bonus Amount at its discretion.

PART III

The information required by Part III is omitted from this Report because we will file a definitive proxy statement pursuant to Regulation 14A of the Securities Exchange Act of 1934 no later than 120 days after the end of the fiscal year covered by this Report and certain information included therein is incorporated herein by reference.

Item 10. *Directors, Executive Officers and Corporate Governance.*

The information required by this Item is incorporated herein by reference to the Proxy Statement.

Item 11. *Executive Compensation.*

The information required by this Item is incorporated herein by reference to the Proxy Statement.

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

The information required by this Item is incorporated herein by reference to the Proxy Statement.

Item 13. *Certain Relationships, Related Transactions and Director Independence.*

The information required by this Item is incorporated herein by reference to the Proxy Statement.

Item 14. *Principal Accountant Fees and Services.*

The information required by this Item is incorporated herein by reference to the Proxy Statement.

PART IV

Item 15. *Exhibits and Financial Statement Schedule.*

(a)(1) *Financial Statements*

See Index to Consolidated Financial Statements on page F-1 of this Report.

(a)(2) *Financial Statement Schedule*

Schedule II — Valuation and qualifying accounts is filed herewith on page S-1.

All other financial statement schedules have been omitted because they are not applicable or the information required therein is included elsewhere in the financial statements or notes thereto.

(a)(3) *Exhibits*

The following exhibits are filed herewith or incorporated by reference herein.

3.1 Restated Certificate of Incorporation, as amended (filed August 9, 2004 as Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).

3.2 Amendment to Restated Certificate of Incorporation, as amended (filed August 9, 2004 as Exhibit 3.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).

3.3 Amended and Restated Bylaws (filed March 19, 2002 as Exhibit 3.2 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2001 and incorporated herein by reference).

4.1 Rights Agreement dated January 2, 1997, between Patterson Energy, Inc. and Continental Stock Transfer & Trust Company (filed January 14, 1997 as Exhibit 2 to the Company's Registration Statement on Form 8-A and incorporated herein by reference).

4.2 Amendment to Rights Agreement dated as of October 23, 2001 (filed October 31, 2001 as Exhibit 3.4 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2001 and incorporated herein by reference).

4.3 Restated Certificate of Incorporation, as amended (See Exhibits 3.1 and 3.2).

4.4 Registration Rights Agreement with Bear, Stearns and Co. Inc., dated March 25, 1994, as assigned by REMY Capital Partners III, L.P.(filed March 19, 2002 as Exhibit 4.3 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2001 and incorporated herein by reference).

10.1 For additional material contracts, see Exhibits 4.1, 4.2 and 4.4.

10.2 Patterson-UTI Energy, Inc., 1993 Stock Incentive Plan, as amended (filed March 13, 1998 as Exhibit 10.1 to the Company's Registration Statement on Form S-8 (File No. 333-47917) and incorporated herein by reference).*

10.3 Patterson-UTI Energy, Inc. Non-Employee Directors' Stock Option Plan, as amended (filed November 4, 1997 as Exhibit 10.1 to the Company's Registration Statement on Form S-8 (File No. 333-39471) and incorporated herein by reference).*

10.4 Amended and Restated Patterson-UTI Energy, Inc. 2001 Long-Term Incentive Plan (filed November 27, 2002 as Exhibit 4.4 to Post Effective Amendment No. 1 to the Company's Registration Statement on Form S-8 (File No. 333-60470) and incorporated herein by reference).*

10.5 Patterson-UTI Energy, Inc. Amended and Restated 1997 Long-Term Incentive Plan (filed July 28, 2003 as Exhibit 4.7 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 and incorporated herein by reference).*

10.6 Amendment to the Patterson-UTI Energy, Inc. Amended and Restated 1997 Long-Term Incentive Plan (filed August 9, 2004 as Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).*

10.7 Amended and Restated Patterson-UTI Energy, Inc. Non-Employee Director Stock Option Plan(filed July 28, 2003 as Exhibit 4.8 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 and incorporated herein by reference).*

10.8 Amended and Restated Patterson-UTI Energy, Inc. 1996 Employee Stock Option Plan (filed July 25, 2001 as Exhibit 4.4 to Post-Effective Amendment No. 1 to the Company's Registration Statement on Form S-8 (File No. 333-60466) and incorporated herein by reference).*

10.9 Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan, including Form of Executive Officer Restricted Stock Award Agreement, Form of Executive Officer Stock Option Agreement, Form of Non-Employee Director Restricted Stock Award Agreement and Form of Non-Employee Director Stock Option Agreement (filed June 15, 2005 as Exhibit 10.1 to the Company's Current Report on Form 8-K, and incorporated herein by reference).*

10.10 Restricted Stock Award Agreement dated April 28, 2004 between Patterson-UTI Energy, Inc. and Mark S. Siegel (filed August 9, 2004 as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).*

10.11 Restricted Stock Award Agreement dated April 28, 2004 between Patterson-UTI Energy, Inc. and Cloyce A. Talbott (filed August 9, 2004 as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).*

10.12 Restricted Stock Award Agreement dated April 28, 2004 between Patterson-UTI Energy, Inc. and A. Glenn Patterson (filed August 9, 2004 as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).*

10.13 Restricted Stock Award Agreement dated April 28, 2004 between Patterson-UTI Energy, Inc. and Kenneth N. Berns (filed August 9, 2004 as Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).*

10.14 Restricted Stock Award Agreement dated April 28, 2004 between Patterson-UTI Energy, Inc. and John E. Vollmer III (filed August 9, 2004 as Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).*

10.15 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and Mark S. Siegel (filed on February 4, 2004 as Exhibit 10.2 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*

10.16 Employment Agreement, effective as of May 3, 2006 between Patterson-UTI Energy, Inc. and A. Glenn Patterson (filed on May 5, 2006 as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2006 and incorporated herein by reference).*

10.17 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and Cloyce A. Talbott (filed on February 4, 2004 as Exhibit 10.4 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*

10.18 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and Kenneth N. Berns (filed on February 4, 2004 as Exhibit 10.5 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*

10.19 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and John E. Vollmer III (filed on February 4, 2004 as Exhibit 10.7 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*

10.20 Form of Letter Agreement regarding termination, effective as of January 29, 2004, entered into by Patterson-UTI Energy, Inc. with each of Mark S. Siegel, Kenneth N. Berns and John E. Vollmer III (filed on February 25, 2005 as Exhibit 10.23 to the Company's Annual Report on Form 10-K for the year ended December 31, 2004 and incorporated herein by reference).*

10.21 Form of Indemnification Agreement entered into by Patterson-UTI Energy, Inc. with each of Mark S. Siegel, Cloyce A. Talbott, A. Glenn Patterson, Kenneth N. Berns, Robert C. Gist, Curtis W. Huff, Terry H. Hunt, Kenneth R. Peak, Nadine C. Smith and John E. Vollmer III (filed April 28, 2004 as Exhibit 10.11 to the Company's Annual Report on Form 10-K, as amended, for the year ended December 31, 2003 and incorporated herein by reference).*

10.22 Credit Agreement dated as of December 17, 2004 among Patterson-UTI Energy, Inc., as the Borrower, Bank of America, N.A., as administrative agent, L/C Issuer and a Lender and the other lenders and agents party thereto (filed on December 23, 2004 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.23 Commitment Increase and Joinder Agreement, dated as of August 2, 2006, by and among Patterson-UTI Energy, Inc., the guarantors party thereto, the lenders party thereto, and Bank of America, N.A. as Administrative Agent, L/C Issuer and Lender (filed August 21, 2006 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.24 Letter Agreement dated February 6, 2006 between Patterson-UTI Energy, Inc. and John E. Vollmer III (filed May 1, 2006 as Exhibit 10.25 to the Company's Annual Report on Form 10-K, as amended, and incorporated herein by reference).*

14.1 Patterson-UTI Energy, Inc. Code of Business Conduct and Ethics for Senior Financial Executives (filed on February 4, 2004 as Exhibit 14.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).

21.1 Subsidiaries of the Registrant.

23.1 Consent of Independent Registered Public Accounting Firm.

31.1 Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended.

31.2 Certification of Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended.

32.1 Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 USC Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

---

* Management Contract or Compensatory Plan identified as required by Item 15(a)(3) of Form 10-K.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of
Patterson-UTI Energy, Inc.:

We have completed integrated audits of Patterson-UTI Energy, Inc.'s consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements and financial statement schedule

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Patterson-UTI Energy, Inc. and its subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A, that the Company maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control — Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP
Houston, Texas
February 26, 2007

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2006	December 31, 2005
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 13,385	$ 136,398
Accounts receivable, net of allowance for doubtful accounts of $7,484 and $2,199 at December 31, 2006 and 2005, respectively	484,106	422,002
Accrued Federal and state income taxes receivable	5,448	—
Inventory	43,947	27,907
Deferred tax assets, net	48,868	26,382
Deposit on equipment purchase contract	24,746	—
Other	32,170	25,168
Total current assets	652,670	637,857
Property and equipment, at cost, net	1,435,804	1,053,845
Goodwill	99,056	99,056
Other	4,973	5,023
Total assets	$2,192,503	$1,795,781
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 138,372	$ 113,226
Accrued revenue distributions	15,359	13,379
Other	18,424	5,294
Accrued Federal and state income taxes payable	—	11,034
Accrued expenses	145,463	112,476
Total current liabilities	317,618	255,409
Borrowings under line of credit	120,000	—
Deferred tax liabilities, net	187,960	169,188
Other	4,459	4,173
Total liabilities	630,037	428,770
Commitments and contingencies	—	—
Stockholders' equity:		
Preferred stock, par value $.01; authorized 1,000,000 shares, no shares issued	—	—
Common stock, par value $.01; authorized 300,000,000 shares with 176,656,401 and 175,909,274 issued and 156,542,512 and 172,441,178 outstanding at December 31, 2006 and 2005, respectively	1,766	1,759
Additional paid-in capital	681,069	672,151
Deferred compensation	—	(9,287)
Retained earnings	1,346,542	719,113
Accumulated other comprehensive income, net of tax	8,390	8,565
Treasury stock, at cost, 20,113,889 shares and 3,468,096 shares at December 31, 2006 and 2005, respectively	(475,301)	(25,290)
Total stockholders' equity	1,562,466	1,367,011
Total liabilities and stockholders' equity	$2,192,503	$1,795,781

The accompanying notes are an integral part of these consolidated financial statements.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2006	2005	2004
	(In thousands, except per share data)		
Operating revenues:			
Contract drilling	$2,169,370	$1,485,684	$ 809,691
Pressure pumping	145,671	93,144	66,654
Drilling and completion fluids	192,358	122,011	90,557
Oil and natural gas	39,187	39,616	33,867
	2,546,586	1,740,455	1,000,769
Operating costs and expenses:			
Contract drilling	1,002,001	776,313	556,869
Pressure pumping	77,755	54,956	37,561
Drilling and completion fluids	150,372	98,530	76,503
Oil and natural gas	13,374	9,566	7,978
Depreciation, depletion and impairment	196,370	156,393	122,800
Selling, general and administrative	55,065	39,110	31,983
Embezzlement costs, net of recoveries	3,081	20,043	19,122
Other operating expenses	9,404	4,248	(514)
	1,507,422	1,159,159	852,302
Operating income	1,039,164	581,296	148,467
Other income (expense):			
Interest income	5,925	3,551	1,140
Interest expense	(1,602)	(516)	(695)
Other	347	428	235
	4,670	3,463	680
Income before income taxes and cumulative effect of change in accounting principle	1,043,834	584,759	149,147
Income tax expense (benefit):			
Current	375,373	194,918	39,952
Deferred	(4,106)	17,101	14,849
	371,267	212,019	54,801
Income before cumulative effect of change in accounting principle	672,567	372,740	94,346
Cumulative effect of change in accounting principle, net of related income tax expense of $398	687	—	—
Net income	$ 673,254	$ 372,740	$ 94,346
Net income per common share:			
Basic:			
Income before cumulative effect of change in accounting principle	$ 4.07	$ 2.19	$ 0.57
Cumulative effect of change in accounting principle	$ —	$ —	$ —
Net income	$ 4.08	$ 2.19	$ 0.57
Diluted:			
Income before cumulative effect of change in accounting principle	$ 4.02	$ 2.15	$ 0.56
Cumulative effect of change in accounting principle	$ —	$ —	$ —
Net income	$ 4.02	$ 2.15	$ 0.56
Weighted average number of common shares outstanding:			
Basic	165,159	170,426	166,258
Diluted	167,413	173,767	169,211

The accompanying notes are an integral part of these consolidated financial statements.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

	Common Stock							
	Number of Shares	Amount	Additional Paid-In Capital	Deferred Compensation	Retained Earnings	Accumulated Other Comprehensive Income	Treasury Stock	Total
				(In thousands)				
Balance, December 31, 2003	82,483	$ 825	$506,018	$ —	$ 290,237	$4,389	$ (11,655)	$ 789,814
Issuance of common stock for acquisition	1,388	14	49,462	—	—	—	—	49,476
Issuance of restricted stock	189	2	6,640	(6,642)	—	—	—	—
Amortization of deferred compensation expense	—	—	—	1,222	—	—	—	1,222
Exercise of stock options and warrants	2,580	25	24,494	—	—	—	—	24,519
Tax benefit related to exercise of stock options	—	—	10,666	—	—	—	—	10,666
Foreign currency translation adjustment (net of tax of $1,716)	—	—	—	—	—	2,961	—	2,961
Purchase of treasury stock	—	—	—	—	—	—	(1,482)	(1,482)
Payment of cash dividend (see Note 10)	—	—	—	—	(10,021)	—	—	(10,021)
Effect of two-for-one stock split (see Note 10)	84,986	850	—	—	(850)	—	—	—
Net income	—	—	—	—	94,346	—	—	94,346
Balance, December 31, 2004	171,626	1,716	597,280	(5,420)	373,712	7,350	(13,137)	961,501
Issuance of restricted stock	305	3	8,040	(8,043)	—	—	—	—
Amortization of deferred compensation expense	—	—	—	2,825	—	—	—	2,825
Forfeitures of restricted shares	(65)	—	(1,351)	1,351	—	—	—	—
Exercise of stock options	4,043	40	43,434	—	—	—	—	43,474
Tax benefit related to exercise of stock options	—	—	24,748	—	—	—	—	24,748
Foreign currency translation adjustment (net of tax of $705)	—	—	—	—	—	1,215	—	1,215
Purchase of treasury stock	—	—	—	—	—	—	(12,153)	(12,153)
Payment of cash dividend (see Note 10)	—	—	—	—	(27,339)	—	—	(27,339)
Net income	—	—	—	—	372,740	—	—	372,740
Balance, December 31, 2005	175,909	1,759	672,151	(9,287)	719,113	8,565	(25,290)	1,367,011
Elimination of deferred compensation due to change in accounting principle	—	—	(9,287)	9,287	—	—	—	—
Issuance of restricted stock	613	6	(6)	—	—	—	—	—
Forfeitures of restricted shares	(47)	(1)	1	—	—	—	—	—
Exercise of stock options	181	2	1,944	—	—	—	—	1,946
Tax benefit related to exercise of stock options	—	—	1,087	—	—	—	—	1,087
Stock based compensation, net of cumulative effect of change in accounting principle	—	—	15,179	—	—	—	—	15,179
Foreign currency translation adjustment, (net of tax of $6)	—	—	—	—	—	(175)	—	(175)
Payment of cash dividend (see Note 10)	—	—	—	—	(45,825)	—	—	(45,825)
Purchase of treasury stock	—	—	—	—	—	—	(450,011)	(450,011)
Net income	—	—	—	—	673,254	—	—	673,254
Balance, December 31, 2006	176,656	$1,766	$681,069	$ —	$1,346,542	$8,390	$(475,301)	$1,562,466

The accompanying notes are an integral part of these consolidated financial statements.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN CASH FLOWS

	Years Ended December 31,		
	2006	2005	2004
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 673,254	$ 372,740	$ 94,346
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and impairment	196,370	156,393	122,800
Provision for bad debts	5,400	1,231	897
Dry holes and abandonments	4,338	—	—
Deferred income tax expense (benefit)	(3,708)	17,101	14,849
Tax benefit related to exercise of stock options	—	24,748	10,666
Stock based compensation expense	15,179	2,825	1,222
(Gain) loss on disposal of assets	3,819	(1,253)	(1,411)
Changes in operating assets and liabilities, net of business acquired:			
Accounts receivable	(67,417)	(208,248)	(50,682)
Federal income taxes receivable/payable	(16,231)	7,068	15,734
Inventory and other current assets	(47,406)	(9,402)	(13,556)
Accounts payable	27,184	60,860	12,861
Accrued expenses	32,972	32,514	1,555
Other liabilities	13,416	3,902	(6,090)
Net cash provided by operating activities	837,170	460,479	203,191
Cash flows from investing activities:			
Acquisitions, net of cash acquired	—	(73,577)	(30,387)
Purchases of property and equipment	(597,919)	(380,094)	(174,589)
Proceeds from disposal of property and equipment	10,934	12,674	3,303
Change in other assets	—	1,766	(1,766)
Net cash used in investing activities	(586,985)	(439,231)	(203,439)
Cash flows from financing activities:			
Purchase of treasury stock	(450,011)	(12,153)	(1,482)
Dividends paid	(45,825)	(27,339)	(10,021)
Tax benefit related to exercise of stock options	1,087	—	—
Proceeds from borrowings under line of credit	274,000	—	—
Repayments on line of credit	(154,000)	—	—
Line of credit issuance costs	(342)	—	(780)
Proceeds from exercise of stock options and warrants	1,946	43,474	24,519
Net cash provided by (used in) financing activities	(373,145)	3,982	12,236
Effect of foreign exchange rate changes on cash	(53)	(1,203)	(100)
Net increase (decrease) in cash and cash equivalents	(123,013)	24,027	11,888
Cash and cash equivalents at beginning of year	136,398	112,371	100,483
Cash and cash equivalents at end of year	$ 13,385	$ 136,398	$ 112,371
Supplemental disclosure of cash flow information:			
Net cash paid during the year for:			
Interest expense	$ (1,278)	$ (418)	$ (245)
Income taxes	(377,847)	(156,709)	(12,500)

The accompanying notes are an integral part of these consolidated financial statements.

1. Description of Business and Summary of Significant Accounting Policies

A description of the business and basis of presentation follows:

Description of business — Patterson-UTI Energy, Inc., together with its wholly-owned subsidiaries, (collectively referred to herein as “Patterson-UTI” or the “Company”) is a leading provider of onshore contract drilling services to major and independent oil and natural gas operators in Texas, New Mexico, Oklahoma, Arkansas, Louisiana, Mississippi, Colorado, Utah, Wyoming, Montana, North Dakota, South Dakota and Western Canada. The Company provides pressure pumping services to oil and natural gas operators primarily in the Appalachian Basin. The Company provides drilling fluids, completion fluids and related services to oil and natural gas operators offshore in the Gulf of Mexico and on land in Texas, Southeastern New Mexico, Oklahoma and the Gulf Coast region of Louisiana. The Company is also engaged in the development, exploration, acquisition and production of oil and natural gas. The Company’s oil and natural gas business operates primarily in producing regions of West and South Texas, Southeastern New Mexico, Utah and Mississippi.

Basis of presentation — The consolidated financial statements include the accounts of Patterson-UTI and its wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated. The Company has no controlling financial interests in any entity that is not a wholly-owned subsidiary which would require consolidation.

The U.S. dollar is the functional currency for all of the Company’s operations except for its Canadian operations, which use the Canadian dollar as their functional currency. The effects of exchange rate changes are reflected in accumulated other comprehensive income, which is a separate component of stockholders’ equity.

On April 28, 2004, the Company’s Board of Directors authorized a two-for-one stock split in the form of a stock dividend which was distributed on June 30, 2004 to holders of record on June 14, 2004. At June 30, 2004, an adjustment was made to reclassify an amount from retained earnings to common stock to account for the par value of the common stock issued as a stock dividend. This adjustment had no overall effect on equity. Historical net income per common share amounts included in the Statements of Income and elsewhere in these financial statements have been presented as if the two-for-one stock split had occurred on January 1, 2004.

A summary of the significant accounting policies follows:

Management estimates — The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from such estimates.

Revenue recognition — Revenues are recognized when services are performed, except for revenues earned under turnkey contract drilling arrangements which are recognized using the completed contract method of accounting, as described below. The Company follows the percentage-of-completion method of accounting for footage and daywork contract drilling arrangements. Under the percentage-of-completion method, management estimates are relied upon in the determination of the total estimated expenses to be incurred drilling the well. Due to the nature of turnkey contract drilling arrangements and risks therein, the Company follows the completed contract method of accounting for such arrangements. Under this method, all drilling revenues and expenses related to a well in progress are deferred and recognized in the period the well is completed. Provisions for losses on incomplete or in-process wells are made when estimated total expenses are expected to exceed estimated total revenues. The Company recognizes reimbursements received from third parties for out-of-pocket expenses incurred as revenues and accounts for these out-of-pocket expenses as direct costs.

Accounts receivable — Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The allowance for doubtful accounts represents the Company’s estimate of the amount of probable credit losses existing in the Company's accounts receivable. The Company reviews the adequacy of its allowance for doubtful accounts monthly. Significant individual accounts receivable balances and balances which have been outstanding greater than 90 days are reviewed individually for collectibility. Account balances, when determined to be uncollectible, are charged against the allowance.

Inventories — Inventories consist primarily of chemical products to be used in conjunction with the Company's drilling and completion fluids and pressure pumping activities. The inventories are stated at the lower of cost or market, determined by the first-in, first-out method.

Property and equipment — Property and equipment is carried at cost less accumulated depreciation. Depreciation is provided on the straight-line method over the estimated useful lives. The method of depreciation does not change when equipment becomes idle. The estimated useful lives, in years, are defined below.

	Useful Lives
Drilling rigs and related equipment	2-15
Office furniture	3-10
Buildings	15-20
Automotive equipment	3-7
Other	3-12

Oil and natural gas properties — Oil and natural gas properties are accounted for using the successful efforts method of accounting. Under the successful efforts method of accounting, exploration costs which result in the discovery of oil and natural gas reserves and all development costs are capitalized to the appropriate well. Exploration costs which do not result in discovering oil and natural gas reserves are charged to expense when such determination is made. Costs of exploratory wells are initially capitalized to wells in progress until the outcome of the drilling is known. The Company reviews wells in progress quarterly to determine whether sufficient progress is being made in assessing the reserves and the economic operating viability of the respective projects. If no progress has been made in assessing the reserves and the economic operating viability of a project after one year following the completion of drilling, the Company considers the costs of the well to be impaired and recognizes the costs as expense. Geological and geophysical costs, including seismic costs, and costs to carry and retain undeveloped properties are charged to expense when incurred. The capitalized costs of both developmental and successful exploratory type wells, consisting of lease and well equipment, lease acquisition costs and intangible development costs, are depreciated, depleted and amortized on the units-of-production method, based on engineering estimates of proved oil and natural gas reserves of each respective field. The Company reviews its proved oil and natural gas properties for impairment when an event occurs such as downward revisions in reserve estimates or decreases in oil and natural gas prices. Proved properties are grouped by field and undiscounted cash flow estimates are provided by an independent petroleum engineer. If the net book value of a field exceeds its undiscounted cash flow estimate, impairment expense is measured and recognized as the difference between its net book value and discounted cash flow. Unproved oil and natural gas properties are reviewed quarterly to determine impairment. The Company's intent to drill, lease expiration and abandonment of area are considered. Assessment of impairment is made on a lease-by-lease basis. If an unproved property is determined to be impaired, costs related to that property are expensed.

Goodwill — Goodwill is considered to have an indefinite useful economic life and is not amortized. As such, the Company assesses impairment of its goodwill annually or on an interim basis if events or circumstances indicate that the fair value of the asset has decreased below its carrying value.

Depreciation, depletion and impairment — The following table summarizes depreciation, depletion and impairment expense for 2006, 2005 and 2004 (in millions):

	2006	2005	2004
Depreciation expense	$181.6	$141.7	$109.4
Depletion expense	9.8	10.3	10.1
Amortization expense	—	—	0.1
Impairment of oil and natural gas properties	5.0	4.4	3.2
Total	$196.4	$156.4	$122.8

Maintenance and repairs — Maintenance and repairs are charged to expense when incurred. Renewals and betterments which extend the life or improve existing property and equipment are capitalized.

Retirements — Upon disposition or retirement of property and equipment, the cost and related accumulated depreciation are removed and any resulting gain or loss is credited or charged to operations.

Net income per common share — The Company provides a dual presentation of its net income per common share; Basic net income per common share ("Basic EPS") and Diluted net income per common share ("Diluted EPS"). Basic EPS excludes dilution and is computed by dividing net income by the weighted average number of unrestricted common shares outstanding during the year. Diluted EPS is based on the weighted average number of common shares outstanding plus the impact of dilutive instruments, including stock options, warrants and restricted shares using the treasury stock method. The following table presents information necessary to calculate net income per share for the years ended December 31, 2006, 2005 and 2004 as well as cash dividends per share paid and potentially dilutive securities excluded from the weighted average number of diluted common shares outstanding as their inclusion would have been anti-dilutive (in thousands, except per share amounts):

	2006	2005	2004
Net income	$673,254	$372,740	$ 94,346
Weighted average number of unrestricted common shares outstanding	165,159	170,426	166,258
Basic net income per common share	$ 4.08	$ 2.19	$ 0.57
Weighted average number of unrestricted common shares outstanding	165,159	170,426	166,258
Dilutive effect of stock options and restricted shares	2,254	3,341	2,953
Weighted average number of diluted common shares outstanding	167,413	173,767	169,211
Diluted net income per common share	$ 4.02	$ 2.15	$ 0.56
Cash dividends per common share	$ 0.28	$ 0.16	$ 0.06
Potentially dilutive securities excluded as anti-dilutive	800	—	640

Income taxes — The asset and liability method is used in accounting for income taxes. Under this method, deferred tax assets and liabilities are recognized for operating loss and tax credit carryforwards and for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the results of operations in the period that includes the enactment date. If applicable, a valuation allowance is recorded to reduce the carrying amounts of deferred tax assets unless it is more likely than not that such assets will be realized.

Stock based compensation — Prior to January 1, 2006, the Company accounted for stock based compensation related to employee stock options and shares of restricted stock using the recognition and measurement principles of

APB Opinion No. 25, *Accounting for Stock Issued to Employees* ("APB 25"), and related interpretations. Under the provisions of APB 25, expense associated with stock option grants was measured based on the intrinsic value of the option at the date of grant and expense associated with restricted stock grants was measured based on the fair value of the shares at the date of grant. Reductions in compensation expense associated with awards that were forfeited prior to vesting were recognized as those grants were forfeited. Effective January 1, 2006, the Company adopted the provisions of Financial Accounting Standards Board Statement No. 123(R), *Accounting for Stock-Based Compensation* ("SFAS 123(R)"). SFAS 123(R) requires the recognition of expense associated with the grant of both stock options and restricted stock based on the estimated fair value of the options or restricted stock at the date of grant, net of estimated forfeitures.

Statement of cash flows — For purposes of reporting cash flows, cash and cash equivalents include cash on deposit, money market funds and investment grade municipal and commercial bonds with original maturities of 90 days or less.

Recently Issued Accounting Standards — In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109* ("FIN 48"). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 is effective for fiscal years beginning after December 15, 2006 and became effective for the Company as of January 1, 2007. The implementation of this standard is not expected to have a material impact in 2007.

In September 2006, the FASB issued Statement No. 157, *Fair Value Measurements* ("FAS 157"). FAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurement. FAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. FAS 157 will be effective for the Company in the quarter ending March 31, 2008. The application of FAS 157 is not expected to have a material impact to the Company.

In September 2006, the SEC staff issued Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements* ("SAB 108"). SAB 108 was issued in order to eliminate the diversity of practice surrounding how public companies quantify financial statement misstatements. Traditionally, there have been two widely-recognized methods for quantifying the effects of financial statement misstatements. The "roll-over" method focuses primarily on the impact of a misstatement on the income statement (including the reversing effect of prior year misstatements) but its use can lead to the accumulation of misstatements in the balance sheet. The "iron-curtain" method, on the other hand, focuses primarily on the effect of correcting the period-end balance sheet with less emphasis on the reversing effects of prior year errors on the income statement. The Company currently uses the iron-curtain method for quantifying identified financial statement misstatements. In SAB 108, the SEC staff established an approach that requires quantification of financial statement misstatements based on the effects of the misstatements on each of the company's financial statements and the related financial statement disclosures. This model is commonly referred to as a "dual approach" because it requires quantification of errors under both the iron curtain and the roll-over methods. The Company applied the provisions of SAB 108 in the quarter ended December 31, 2006 and there was no impact.

Reclassifications — Certain reclassifications have been made to the 2005 and 2004 consolidated financial statements in order for them to conform with the 2006 presentation.

2. Acquisitions

2005 Acquisitions

Key Energy Services, Inc. — On January 15, 2005, the Company purchased land drilling assets from Key Energy Services, Inc. for $61.8 million. The assets included 25 active and 10 stacked land-based drilling rigs, related drilling equipment, yard facilities and a rig moving fleet consisting of approximately 45 trucks and 100 trailers. The transaction was accounted for as an acquisition of assets and the purchase price was allocated among the assets acquired based on their estimated fair market values.

Other — On June 17, 2005, the Company acquired one land-based drilling rig for $3.6 million and on September 29, 2005, the Company acquired five land-based drilling rigs and related drilling equipment for $8.2 million. The transactions were accounted for as acquisitions of assets and the purchase price was allocated among the assets acquired based on their estimated fair market values.

2004 Acquisition

TMBR/Sharp Drilling, Inc. — On February 11, 2004, the Company completed its acquisition of TMBR, a Texas corporation, in which one of its wholly-owned subsidiaries acquired 100% of the outstanding shares of TMBR. Operations of TMBR subsequent to February 11, 2004, are included in the Company's consolidated financial statements. The transaction was accounted for as a business combination and the purchase price was allocated among the assets acquired and liabilities assumed based on their estimated fair market values. The assets of TMBR included 18 land-based drilling rigs and related equipment, shop facilities, equipment yards and oil and natural gas properties.

The purchase price was calculated as follows (in thousands, except per share data and exchange ratio):

Cash of $9.09 per share for the 4,447 TMBR shares outstanding at February 11, 2004, excluding the 1,059 TMBR shares owned by Patterson-UTI	$ 40,423
Patterson-UTI shares issued at $17.82 per share (4,447 TMBR shares X .624332 exchange ratio X $17.82)	49,476
1,059 TMBR shares previously acquired by the Company	19,771
Acquisition costs	10,511
Less: Cash acquired	(7,909)
Total purchase price	$112,272

The purchase price was allocated among assets acquired and liabilities assumed based on their estimated fair market values as follows (in thousands):

Current assets	$ 7,181
Property and equipment	60,784
Other long term assets	172
Deferred tax assets	13,080
Goodwill	48,020
Current liabilities	(7,080)
Other long term liabilities	(1,090)
Deferred tax liability	(8,795)
Total purchase allocation	$112,272

The Company acquired TMBR to increase its productive asset base in the Permian Basin, which is one of the most active land drilling regions in the U.S. TMBR was well established in the contract drilling industry and maintained favorable customer relationships. Goodwill was recognized in the transaction as a result of these factors.

The following represents pro-forma unaudited financial information as if the acquisition had been completed on January 1, 2004 (in thousands, except per share amounts):

	2004
Revenue	$1,005,357
Income before cumulative effect of change in accounting principle	94,047
Net income	94,047
Earnings per share:	
Basic	$ 0.57
Diluted	$ 0.56

3. Comprehensive Income

The following table illustrates the Company's comprehensive income including the effects of foreign currency translation adjustments for the years ended December 31, 2006, 2005 and 2004 (in thousands):

	2006	2005	2004
Net income	$673,254	$372,740	$94,346
Other comprehensive income:			
Foreign currency translation adjustment related to Canadian operations, net of tax	(175)	1,215	2,961
Comprehensive income	$673,079	$373,955	$97,307

4. Property and Equipment

Property and equipment consisted of the following at December 31, 2006 and 2005 (in thousands):

	2006	2005
Equipment	$2,135,567	$1,633,911
Oil and natural gas properties	85,143	79,079
Buildings	30,987	22,490
Land	7,507	5,611
	2,259,204	1,741,091
Less accumulated depreciation and depletion	(823,400)	(687,246)
	$1,435,804	$1,053,845

5. Goodwill

Goodwill is evaluated annually to determine if the fair value of the asset has decreased below its carrying value. At December 31, 2006 the Company performed its annual goodwill evaluation and determined that no adjustment to impair goodwill was necessary. Goodwill as of December 31, 2006 and 2005 included $89,092 in the contract drilling segment and $9,964 in the drilling and completion fluids segment. For purposes of impairment testing, goodwill is evaluated at the reporting unit level. The Company's reporting units for impairment testing have been determined to be its operating segments. There were no changes to goodwill during the years ended December 31, 2006 and 2005.

6. Accrued Expenses

Accrued expenses consisted of the following at December 31, 2006 and 2005 (in thousands):

	2006	2005
Salaries, wages, payroll taxes and benefits	$ 42,751	$ 33,816
Workers' compensation liability	67,615	47,107
Sales, use and other taxes	11,043	9,484
Insurance, other than workers' compensation	13,328	11,365
Other	10,726	10,704
	$145,463	$112,476

7. Asset Retirement Obligation

Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations,* ("SFAS 143"), requires that the Company record a liability for the estimated costs to be incurred in connection with the abandonment of oil and natural gas properties in the future. The following table describes the changes to the Company's asset retirement obligations during 2006 and 2005 (in thousands):

	2006	2005
Balance at beginning of year	$1,725	$2,358
Liabilities incurred	154	101
Liabilities settled	(104)	(808)
Accretion expense	54	74
Asset retirement obligation at end of year	$1,829	$1,725

8. Borrowings Under Line of Credit

The Company entered into a five-year, $200 million unsecured revolving line of credit ("LOC") in December 2004. Interest is to be paid on outstanding LOC balances at a floating rate ranging from LIBOR plus 0.625% to 1.0% or the prime rate. Any outstanding borrowings must be repaid at maturity on December 16, 2009. This arrangement includes various fees, including a commitment fee on the average daily unused amount (0.15% at December 31, 2006). There are customary restrictions and covenants associated with the LOC. Financial covenants provide for a maximum debt to capitalization ratio and a minimum interest coverage ratio. The Company does not expect that the restrictions and covenants will restrict its ability to operate or react to opportunities that might arise. On August 2, 2006, the Company entered into an agreement to amend the LOC. In connection with this amendment, the borrowing capacity under this LOC was increased to $375 million. No significant changes were made to the terms of the LOC including the interest to be paid on outstanding balances and financial covenants. As of December 31, 2006, the Company had borrowed $120 million under the LOC and $60 million in letters of credit were outstanding. As a result, the Company had available borrowing capacity of $195 million at December 31, 2006. The weighted average interest rate on borrowings outstanding at December 31, 2006 was 6.92%.

9. Commitments, Contingencies and Other Matters

Commitments — The Company maintains letters of credit in the aggregate amount of approximately $60 million for the benefit of various insurance companies as collateral for retrospective premiums and retained losses which may become payable under the terms of the underlying insurance contracts. These letters of credit are typically renewed annually. No amounts have been drawn under the letters of credit.

As of December 31, 2006, the Company has signed non-cancelable commitments to purchase approximately $297 million of equipment to be received throughout 2007. This amount excludes a $24.7 million deposit that was paid during 2006 pursuant to an agreement that was entered into to purchase rig components to be used in the construction of 15 new land drilling rigs. This payment is presented as a deposit on equipment purchase contract in the consolidated balance sheet at December 31, 2006.

Contingencies — The Company's contract services and oil and natural gas exploration and production operations are subject to inherent risks, including blowouts, cratering, fire and explosions which could result in personal injury or death, suspended drilling operations, damage to, or destruction of equipment, damage to producing formations and pollution or other environmental hazards.

As a protection against these hazards, the Company maintains general liability insurance coverage of $2.0 million per occurrence with $4.0 million of aggregate coverage and excess liability and umbrella coverages up to $100 million per occurrence and in the aggregate. The Company maintains a $1.0 million per occurrence deductible on its workers' compensation insurance and its general liability insurance coverages.

The Company believes it is adequately insured for public liability and property damage to others with respect to its operations. However, such insurance may not be sufficient to protect the Company against liability for all consequences of well disasters, extensive fire damage, or damage to the environment. The Company also carries insurance to cover physical damage to, or loss of, its rigs. However, it does not cover the full replacement cost of the rigs and the Company does not carry insurance against loss of earnings resulting from such damage or loss.

Net income for the year ended December 31, 2005 includes a charge of $4.2 million related to the financial failure of a workers' compensation insurance carrier that had provided coverage for the Company in prior years.

In November 2005, the Company discovered that its former Chief Financial Officer, Jonathan D. Nelson ("Nelson"), had fraudulently diverted approximately $77.5 million in Company funds for his own benefit. As a result, the Audit Committee of the Board of Directors commenced an investigation into Nelson's activities and retained independent counsel and independent forensic accountants to assist with the investigation. Nelson has been sentenced and is serving a term of imprisonment arising out of his embezzlement. A receiver has been appointed to take control of and liquidate the assets of Nelson in connection with his embezzlement of Company funds. The receiver is in the process of seeking court approval for a plan of distribution of the assets recovered by the receiver and the proceeds thereof, which total approximately $40 million. While the Company believes it has a claim for at least the full amount of funds embezzled from the Company, other creditors have asserted or may assert claims with respect to the assets held by the receiver.

In December 2005, two purported derivative actions were filed in Texas state court in Scurry County, Texas and in May 2006, a derivative action was filed in federal court in Lubbock, Texas, in each case, against the Company's directors, alleging that the directors breached their fiduciary duties to the Company as a result of alleged failure to timely discover the embezzlement of approximately $77.5 million by its former CFO, Jonathan D. Nelson. The Board of Directors formed a special litigation committee to review and inquire about these allegations and recommend the Company's response, if any. Further legal proceedings in these suits were stayed pending completion of the work of the special litigation committee. The lawsuits sought recovery on behalf of and for the Company and did not seek recovery from the Company. In November 2006, the parties to all three of the derivative actions reached an agreement to settle the actions. After a preliminary hearing and notice to the Company's stockholders, the state court held a hearing, approved the settlement, which required the implementation of certain corporate governance measures, and signed a final judgment on December 29, 2006. As contemplated by the settlement agreement, the federal court entered a final judgment on January 10, 2007. Pursuant to the terms of the settlement, the Company will pay a net amount of $230,000 to the attorneys for the plaintiffs in the suits.

The Company is party to various other legal proceedings arising in the normal course of its business. The Company does not believe that the outcome of these proceedings, either individually or in the aggregate, will have a material adverse effect on its financial condition.

Other Matters — The Company has Change in Control Agreements with its Chairman of the Board, Chief Executive Officer and two Senior Vice Presidents (the "Key Employees"). Each Change in Control Agreement generally has a three-year term with automatic twelve month renewals unless the Company notifies the Key Employee at least ninety days before the end of such renewal period that the term will not be extended. If a change in control of the Company occurs during the term of the agreement and the Key Employee's employment is terminated

(i) by the Company other than for cause or other than automatically as a result of death, disability or retirement or (ii) by the Key Employee for good reason (as those terms are defined in the Change in Control Agreements), then the Key Employee shall be entitled to, among other things,

- bonus payment equal to the greater of the highest bonus paid after the Change in Control Agreement was entered into and the average of the two annual bonuses earned in the two fiscal years immediately preceding a change in control (such bonus payment prorated for the portion of the fiscal year preceding the termination date);
- a payment equal to 2.5 times (in the case of the Chairman of the Board and Chief Executive Officer) or 1.5 times (in the case of the Senior Vice Presidents) of the sum of (i) the highest annual salary in effect for such Key Employee and (ii) the average of the three annual bonuses earned by the Key Employee for the three fiscal years preceding the termination date; and
- continued coverage under the Company's welfare plans for up to three years (in the case of the Chairman of the Board and Chief Executive Officer) or two years (in the case of the Senior Vice Presidents).

Each Change in Control Agreement provides the Key Employee with a full gross-up payment for any excise taxes imposed on payments and benefits received under the Change in Control Agreements or otherwise, including other taxes that may be imposed as a result of the gross-up payment.

10. Stockholders' Equity

The Company has granted restricted shares of the Company's common stock ("Restricted Shares") to certain key employees under the Patterson-UTI Energy, Inc. 1997 Long-Term Incentive Plan, as amended, and the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan. As required by SFAS 123(R), the Restricted Shares were valued based upon the market price of the Company's common stock on the date of the grant. The restrictions on these shares lapse at various dates through 2010.

On June 7, 2004, the Company's Board of Directors authorized a stock buyback program for the purchase of up to $30 million of the Company's outstanding common stock. During 2004, the Company purchased 100,000 shares of its common stock under this program in the open market for approximately $1.5 million. During 2005, the Company purchased 355,000 shares of its common stock under this program in the open market for approximately $12.2 million. On March 27, 2006, the Company's Board of Directors increased the stock buyback program to allow for future purchases of up to $200 million of the Company's outstanding common stock. During the second quarter of 2006, the Company completed the purchase of 6,704,800 shares of its common stock under this program in the open market at a cost of approximately $200 million. On August 2, 2006, the Company's Board of Directors again increased the stock buyback program to allow for future purchases of up to $250 million of the Company's outstanding common stock. During the remainder of 2006, the Company purchased an additional 9,940,542 shares of its common stock under this program in the open market at a cost of approximately $250 million. Shares purchased under the stock buyback program have been accounted for as treasury stock.

On April 28, 2004, the Company's Board of Directors authorized a two-for-one stock split in the form of a stock dividend which was distributed on June 30, 2004 to holders of record on June 14, 2004. In connection with the two-for-one stock split, an adjustment was made to reclassify an amount from retained earnings to common stock to account for the par value of the common stock issued as a stock dividend. This adjustment had no overall effect on equity. Historical net income per common share amounts included in the Consolidated Statements of Income and elsewhere in these financial statements have been presented as if the two-for-one stock split had occurred on January 1, 2004.

On April 28, 2004, the Company's Board of Directors approved the initiation of a quarterly cash dividend of $0.02 on each share of its common stock which was paid on June 2, 2004, September 1, 2004 and December 1, 2004. Total dividends paid in 2004 were approximately $10.0 million. In February 2005, the Company's Board of Directors approved an increase in the quarterly cash dividend on the Company's common stock to $0.04 per share. Quarterly cash dividends in the amount of $0.04 per share were paid on March 4, 2005, June 1, 2005, September 1, 2005 and December 1, 2005. Total cash dividends in 2005 were approximately $27.3 million. On March 2, 2006, the Company's Board of Directors approved a cash dividend on its common stock in the amount of $0.04 per share which was paid on March 30, 2006. On April 26, 2006, the Company's Board of Directors approved an increase in its quarterly cash dividend from $0.04 to $0.08 on each outstanding share of its common stock. Cash dividends of $0.08 per share were paid on June 30, 2006, September 29, 2006 and December 29, 2006. Total cash dividends in 2006 were approximately $45.8 million. The amount and timing of all future dividend payments is subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial condition, terms of the Company's credit facilities and other factors.

In February 2004, the Company completed its acquisition of TMBR in which one of its wholly-owned subsidiaries acquired 100% of the outstanding shares of TMBR for a net cash payment of $32.5 million ($40.4 million paid to TMBR shareholders less $7.9 million in cash acquired in the transaction) and the issuance of 2.78 million shares of the Company's common stock valued at $17.82 per share (adjusted to reflect the two-for-one stock split on June 30, 2004). The assets of TMBR included 18 land-based drilling rigs and related equipment, shop facilities, equipment yards and their oil and natural gas properties. The transaction was accounted for as a business combination and the purchase price was allocated among the assets acquired and liabilities assumed based on their estimated fair market values (see Note 2).

11. Stock-based Compensation

The Company adopted FASB 123(R) on January 1, 2006 and recognizes the cost of share-based payments under the fair-value-based method. The Company uses share-based payments to compensate employees and non-employee directors. All awards have been equity instruments in the form of stock options or restricted stock awards and include only service conditions. The Company issues shares of common stock when vested stock option awards are exercised and when restricted stock awards are granted. For the year ended December 31, 2006, the Company recognized $16.3 million in stock-based compensation expense and a related income tax benefit of approximately $5.8 million and recognized a benefit in the form of a cumulative effect of change in accounting principle associated with the adoption of FAS 123(R) of $1.1 million, with a related tax expense of $398,000. As a result of the adoption of FAS 123(R) in 2006, operating income and income before income taxes was reduced by $8.4 million. Net income was reduced by $4.7 million. Basic EPS and Diluted EPS were reduced by $0.03 per share as a result of the adoption of FAS 123(R).

During 2005, the Company's shareholders approved the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (the "2005 Plan") and the Board of Directors adopted a resolution that no future grants would be made under any of the Company's other previously existing plans. The Company's share-based compensation plans at December 31, 2006 follow:

Plan Name	Shares Authorized for Grant	Options & Restricted Shares Outstanding	Shares Available for Grant
Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan	6,250,000	1,540,252	4,140,197
Patterson-UTI Energy, Inc. Amended and Restated 1997 Long-Term Incentive Plan, as amended ("1997 Plan")	—	5,090,885	—
Amended and Restated Patterson-UTI Energy, Inc. 2001 Long-Term Incentive Plan ("2001 Plan")	—	762,559	—
Amended and Restated Non-Employee Director Stock Option Plan of Patterson-UTI Energy, Inc. ("Non-Employee Director Plan")	—	150,000	—
Amended and Restated Patterson-UTI Energy, Inc. 1996 Employee Stock Option Plan ("1996 Plan")	—	95,800	—
Patterson-UTI Energy, Inc., 1993 Incentive Stock Plan, as amended ("1993 Plan")	—	123,800	—

A summary of the 2005 Plan follows:

- The Compensation Committee of the Board of Directors administers the plan.
- All employees including officers and directors are eligible for awards.
- The Compensation Committee determines the vesting schedule for awards. Awards typically vest over 1 year for non-employee directors and 3 to 4 years for employees.
- The Compensation Committee sets the term of awards and no option term can exceed 10 years.
- All options granted under the plan are granted with an exercise price equal to or greater than the fair market value of the Company's common stock at the time the option is granted.
- The plan provides for awards of incentive stock options, non-incentive stock options, tandem and free-standing stock appreciation rights, restricted stock awards, other stock unit awards, performance share awards, performance unit awards and dividend equivalents. As of December 31, 2006, only non-incentive stock options and restricted stock awards had been granted under the plan.

Options granted under the 1997 Plan typically vest over three or five years as dictated by the Compensation Committee. These options have terms of no more than ten years. All options were granted with an exercise price equal to the fair market value of the related common stock at the time of grant. Restricted Stock Awards granted under the 1997 Plan typically vest over four years.

Options granted under the 2001 Plan typically vest over five years as dictated by the Compensation Committee. These options have terms of no more than ten years. All options were granted with an exercise price equal to the fair market value of the Company's common stock at the time of grant.

Options granted under the Non-Employee Director Plan vest on the first anniversary of the option grant. Non-Employee Director Plan options have five year terms. All options were granted with an exercise price equal to the fair market value of the related common stock at the time of grant.

Options granted under the 1996 plan typically vest over one, four or five years as dictated by the Compensation Committee. These options have terms of no more than ten years. All options were granted with an exercise price equal to the fair market value of the Company's common stock at the time of grant.

Options granted under the 1993 Plan typically typically vest over five years as dictated by the Compensation Committee. These options have terms of no more than ten years. All options were granted with an exercise price equal to the fair market value of the Company's common stock at the time of grant.

Stock Options — The Company accounted for all stock options under the intrinsic value method prior to January 1, 2006. Accordingly, no compensation expense was recognized in prior periods for stock options because they had no intrinsic value when granted as exercise prices were equal to the grant date market value of the related common stock. The Modified Prospective Application ("MPA") method is being applied to transition from the intrinsic value method to the fair-value-based method for stock options. The effects of the application of the MPA method follow:

- Previously reported amounts and disclosures are not affected.
- Compensation cost, net of estimated forfeitures for the unvested portion of awards outstanding at January 1, 2006, is recognized under the fair-value-based method as the awards vest. Compensation cost is based on the grant-date estimated fair value of stock options as calculated for the Company's previously reported pro forma disclosures under FASB Statement No. 123, *Accounting for Stock-Based Compensation* ("FAS 123").
- The fair-value based method is applied to new awards and to any awards outstanding at January 1, 2006 that are modified, repurchased or cancelled after that date.

The Company estimates grant date fair values of stock options using the Black-Scholes-Merton valuation model ("Black-Scholes"), except for stock options granted prior to 1996 that are not subject to FAS 123(R) and were not subject to FAS 123 pro forma disclosures. Volatility assumptions are based on the historic volatility of the Company's common stock over the most recent period equal to the expected term of the options as of the date the options were granted. The expected term assumptions are based on the Company's experience with respect to employee stock option activity. Dividend yield assumptions are based on the expected dividends at the time the options were granted. The risk-free interest rate assumptions are determined by reference to United States Treasury yields. Weighted-average assumptions used to estimate grant date fair values for stock options granted in the years ended December 31, 2006, 2005 and 2004 follow:

	2006	2005	2004
Volatility	33.18%	26.95%	36.84%
Expected term (in years)	4.00	4.00	3.84
Dividend yield	1.09%	0.65%	0.06%
Risk-free interest rate	4.87%	3.84%	3.22%

Stock option activity for the year ended December 31, 2006 follows:

	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	6,338,044	$14.37
Granted	800,000	$28.54
Exercised	(180,726)	$10.77
Forfeited	(17,000)	$10.94
Expired	(4,389)	$ 9.28
Cancelled(a)	(360,833)	$14.83
Outstanding at end of year	6,575,096	$16.18
Exercisable at end of year	5,392,263	$13.92

(a) Represents vested stock options held by the former CFO which were cancelled by the Company's Board of Directors.

Options outstanding at December 31, 2006 have an aggregate intrinsic value of approximately $51.4 million and have a weighted-average remaining contractual term of 6.21 years. Options exercisable at December 31, 2006 have an aggregate intrinsic value of approximately $50.6 million and have a weighted-average remaining contractual term of 5.60 years. Additional information with respect to options granted and exercised during the years ended December 31, 2006, 2005 and 2004 follows:

	2006	2005	2004
Weighted-average grant-date fair value of stock options granted (per share)	$ 8.62	$ 6.33	$ 6.25
Aggregate intrinsic value of stock options exercised (in thousands)	$3,377	$73,467	$41,171

As of December 31, 2006, options to purchase 1,182,833 shares were outstanding and not vested. Substantially all of these non-vested options are expected to ultimately vest. Additional information as of December 31, 2006 with respect to these options that are expected to vest follows:

Aggregate intrinsic value	$ 766,000
Weighted-average remaining contractual term	8.98 years
Weighted-average remaining expected term	2.99 years
Weighted-average remaining vesting period	1.99 years
Unrecognized compensation cost	$8.2 million

Restricted Stock — Under all restricted stock awards to date, shares were issued when granted, nonvested shares are subject to forfeiture for failure to fulfill service conditions and nonforfeitable dividends are paid on nonvested restricted shares. Restricted stock awards prior to January 1, 2006 were valued at the grant date market value of the underlying common stock, recognized as contra equity deferred compensation and amortized to expense under the "graded-vesting" method. Implementation of FAS 123(R) did not change the accounting for the Company's nonvested stock awards, except as follows:

- Prior to January 1, 2006, forfeitures were recognized as they occurred;
- From January 1, 2006 forward, forfeitures are estimated in the determination of periodic compensation cost;
- Contra equity deferred compensation was reversed against paid-in-capital at January 1, 2006; and
- Compensation expense is recognized as attributed to each period.

The Company uses the "graded-vesting" attribution method to determine periodic compensation cost from restricted stock awards.

Restricted stock activity for the year ended December 31, 2006 follows:

	Shares	Weighted-Average Grant Date Fair Value
Outstanding at beginning of year	623,150	$21.44
Granted	613,400	$30.46
Vested	(1,351)	$14.73
Forfeited	(46,999)	$26.00
Outstanding at end of year	1,188,200	$25.92

As of December 31, 2006, approximately 1,059,000 shares of nonvested restricted stock outstanding are expected to vest. Additional information as of December 31, 2006 with respect to these shares that are expected to vest follows:

Aggregate intrinsic value	$24.6 million
Weighted-average remaining vesting period	2.51 years
Unrecognized compensation cost	$16.0 million

Dividends on Equity Awards — Nonforfeitable dividends paid on equity awards are recognized as follows:

- Dividends are recognized as reductions of retained earnings for the portion of equity awards expected to vest.
- Dividends are recognized as additional compensation cost for the portion of equity awards that are not expected to vest or that ultimately do not vest.

Vesting expectations, in regard to these dividend payments, correspond with forfeiture assumptions used to recognize compensation cost.

Prior Period Pro Forma Disclosures — Prior to January 1, 2006, the Company accounted for share-based compensation under the intrinsic value method. Other than the restricted stock discussed above, no additional share-based compensation expense was reflected in earnings prior to January 1, 2006 since the exercise price was equal to the grant-date market value of the underlying common stock for all stock options granted prior to that date. The effect of share-based compensation, as if the Company had applied the fair-value-based method proscribed by FAS 123, on net income and earnings per share for the yeas ended December 31, 2005 and 2004 (in thousands, except per share amounts):

	2005	2004
Net income, as reported	$372,740	$ 94,346
Add back: Share-based employee compensation cost, net of related tax effects, included in net income as reported	1,795	773
Deduct: Share-based employee compensation cost, net of related tax effects, that would have been included in net income if the fair-value-based method had been applied to all awards	(11,119)	(12,304)
Pro-forma net income	$363,416	$ 82,815
Net income per common share:		
Basic, as reported	$ 2.19	$ 0.57
Basic, pro-forma	$ 2.13	$ 0.50
Diluted, as reported	$ 2.15	$ 0.56
Diluted, pro-forma	$ 2.11	$ 0.49

12. Leases

The Company incurred rent expense of $31.8 million, $22.5 million and $17.8 million, for the years 2006, 2005 and 2004, respectively. The Company's obligations under non-cancelable operating lease agreements are not material to the Company's operations.

13. Income Taxes

Components of the income tax provision applicable for Federal, state and foreign income taxes for the years ended December 31, 2006, 2005 and 2004 are as follows (in thousands):

	2006	2005	2004
Federal income tax expense (benefit):			
Current	$344,395	$174,635	$32,686
Deferred	(5,851)	14,182	12,366
	338,544	188,817	45,052
State income tax expense:			
Current	21,371	13,045	2,031
Deferred	1,392	1,431	1,555
	22,763	14,476	3,586
Foreign income tax expense:			
Current	9,607	7,238	5,235
Deferred	353	1,488	928
	9,960	8,726	6,163
Total:			
Current	375,373	194,918	39,952
Deferred	(4,106)	17,101	14,849
Total income tax expense	$371,267	$212,019	$54,801

The difference between the statutory Federal income tax rate and the effective income tax rate for the years ended December 31, 2006, 2005 and 2004 is summarized as follows:

	2006	2005	2004
Statutory tax rate	35.0%	35.0%	35.0%
State income taxes	1.4	1.8	1.6
Permanent differences	(0.8)	(0.6)	0.4
Other, net	0.0	0.1	(0.3)
Effective tax rate	35.6%	36.3%	36.7%

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. The Company expects the deferred tax assets at December 31, 2006 to be realized as a result of the reversal during the carryforward period of existing taxable temporary differences giving rise to deferred tax liabilities and the generation of taxable income in the carryforward period; therefore, no valuation allowance is necessary.

The tax effect of significant temporary differences representing deferred tax assets and liabilities and changes therein were as follows (in thousands):

	December 31, 2006	Net Change	December 31, 2005	Net Change	December 31, 2004	Net Change	January 1, 2004
Deferred tax assets:							
Current:							
Federal net operating loss carryforwards	$ 1,870	$ —	$ 1,870	$ —	$ 1,870	$ 1,870	$ —
Workers' compensation allowance	26,363	6,902	19,461	4,584	14,877	1,545	13,332
Embezzlement costs	14,294	14,294	—	—	—	—	—
AMT credit	—	—	—	—	—	(602)	602
Other	14,501	3,137	11,364	4,386	6,978	1,238	5,740
	57,028	24,333	32,695	8,970	23,725	4,051	19,674
Non-current:							
Federal net operating loss carryforwards	374	(1,871)	2,245	(1,870)	4,115	4,115	—
AMT credit	118	—	118	—	118	118	—
Federal benefit of foreign deferred tax liabilities	8,549	353	8,196	1,488	6,708	933	5,775
Federal benefit of state deferred tax liabilities	4,692	460	4,232	717	3,515	421	3,094
Embezzlement costs	—	—	—	(22,178)	22,178	7,193	14,985
Other	7,109	6,172	937	174	763	763	—
	20,842	5,114	15,728	(21,669)	37,397	13,543	23,854
Total deferred tax assets	77,870	29,447	48,423	(12,699)	61,122	17,594	43,528
Deferred tax liabilities:							
Current:							
Other	(8,161)	(1,848)	(6,313)	1,421	(7,734)	(4,509)	(3,225)
Non-current:							
Property and equipment basis difference	(203,500)	(23,775)	(179,725)	(6,381)	(173,344)	(25,534)	(147,810)
Other	(5,301)	(110)	(5,191)	(663)	(4,528)	167	(4,695)
	(208,801)	(23,885)	(184,916)	(7,044)	(177,872)	(25,367)	(152,505)
Total deferred tax liabilities	(216,962)	(25,733)	(191,229)	(5,623)	(185,606)	(29,876)	(155,730)
Net deferred tax liability	$(139,092)	$ 3,714	$(142,806)	$(18,322)	$(124,484)	$(12,282)	$(112,202)

Management deducted accumulated net embezzlement losses in the Company's 2005 tax returns, which corresponds with the period in which the embezzlement was detected.

Other deferred tax assets consist primarily of various allowance accounts and tax deferred expenses expected to generate future tax benefit of approximately $22 million. Other deferred tax liabilities consist primarily of receivables from insurance companies and tax deferred income not yet recognized for tax purposes.

For tax purposes, the Company has available at December 31, 2006, Federal net operating loss carryforwards of approximately $5 million and $118,000 of alternative minimum tax credit carryforwards. These carryforwards are attributable to the acquisition of TMBR in February 2004.

The net operating loss carryforwards, if unused, are scheduled to expire as follows: 2018 — $1 million and 2019 — $4 million. The alternative minimum tax credit may be carried forward indefinitely.

14. Employee Benefits

The Company maintains a 401(k) plan for all eligible employees. The Company's operating results include expenses of approximately $3.1 million in 2006, $2.7 million in 2005 and $2.2 million in 2004 for the Company's discretionary contributions to the plan.

15. Business Segments

The Company conducts its business through four distinct operating segments: (1) contract drilling of oil and natural gas wells, (2) pressure pumping services, (3) drilling and completion fluids services to operators in the oil and natural gas industry, and (4) the exploration, development, acquisition and production of oil and natural gas. Each of these segments represents a distinct type of business based upon the type and nature of services and products offered. These segments have separate management teams which report to the Company's chief executive officer and have distinct and identifiable revenues and expenses.

Contract Drilling — The Company markets its contract drilling services to major and independent oil and natural gas operators. As of December 31, 2006, the Company had 336 currently marketable land-based drilling rigs, of which 107 of the drilling rigs were based in the Permian Basin region, 50 in South Texas, 44 in the Ark-La-Tex region and Mississippi, 67 in the Mid-Continent region, 48 in the Rocky Mountain region and 20 in Western Canada.

Pressure Pumping — The Company provides pressure pumping services primarily in the Appalachian Basin. Pressure pumping services consist primarily of well stimulation and cementing for the completion of new wells and remedial work on existing wells. Well stimulation involves processes inside a well designed to enhance the flow of oil, natural gas, or other desired substances from the well. Cementing is the process of inserting material between the hole and the pipe to center and stabilize the pipe in the hole.

Drilling and Completion Fluids — The Company provides drilling fluids, completion fluids and related services to oil and natural gas operators offshore in the Gulf of Mexico and on land in Texas, Southeastern New Mexico, Oklahoma and the Gulf Coast region of Louisiana. Drilling and completion fluids are used by oil and natural gas operators during the drilling process to control pressure when drilling oil and natural gas wells.

Oil and Natural Gas — The Company is engaged in the development, exploration, acquisition and production of oil and natural gas.

The following tables summarize selected financial information relating to the Company's business segments (in thousands):

	Years Ended December 31,		
	2006	2005	2004
Revenues:			
Contract drilling(a)	$2,174,805	$1,488,485	$ 815,683
Pressure pumping	145,671	93,144	66,654
Drilling and completion fluids(b)	192,974	122,309	90,858
Oil and natural gas	39,187	39,616	33,867
Total segment revenues	2,552,637	1,743,554	1,007,062
Elimination of intercompany revenues(a)(b)	(6,051)	(3,099)	(6,293)
Total revenues	$2,546,586	$1,740,455	$1,000,769
Income before income taxes:			
Contract drilling	$ 991,449	$ 572,562	$ 146,626
Pressure pumping	44,835	21,664	16,747
Drilling and completion fluids	28,759	12,201	4,202
Oil and natural gas	8,660	13,405	10,764
	1,073,703	619,832	178,339

	Years Ended December 31,		
	2006	2005	2004
Corporate and other	(22,054)	(14,245)	(11,264)
Other operating expenses(c)	(9,404)	(4,248)	514
Embezzlement costs, net of recoveries(d)	(3,081)	(20,043)	(19,122)
Interest income	5,925	3,551	1,140
Interest expense	(1,602)	(516)	(695)
Other	347	428	235
Income before income taxes	$1,043,834	$ 584,759	$ 149,147
Identifiable assets:			
Contract drilling	$1,849,923	$1,421,779	$ 961,873
Pressure pumping	111,787	72,536	49,145
Drilling and completion fluids	106,032	90,904	62,970
Oil and natural gas	65,443	60,785	62,984
	2,133,185	1,646,004	1,136,972
Corporate and other(e)	59,318	149,777	119,813
Total assets	$2,192,503	$1,795,781	$1,256,785
Depreciation, depletion and impairment:			
Contract drilling	$ 168,607	$ 131,740	$ 101,779
Pressure pumping	9,896	7,094	5,112
Drilling and completion fluids	2,706	2,368	2,156
Oil and natural gas	14,368	14,456	13,309
	195,577	155,658	122,356
Corporate and other	793	735	444
Total depreciation, depletion and impairment	$ 196,370	$ 156,393	$ 122,800
Capital expenditures:			
Contract drilling	$ 531,087	$ 329,073	$ 140,945
Pressure pumping	41,262	25,508	17,705
Drilling and completion fluids	4,222	3,042	1,488
Oil and natural gas	21,198	17,163	14,451
Corporate and other	150	5,308	—
Total capital expenditures	$ 597,919	$ 380,094	$ 174,589

(a) Includes contract drilling intercompany revenues of approximately $5.4 million, $2.8 million and $6.0 million for the years ended December 31, 2006, 2005 and 2004, respectively.

(b) Includes drilling and completion fluids intercompany revenues of approximately $616,000, $298,000 and $301,000 for the years ended December 31, 2006, 2005 and 2004, respectively.

(c) Other operating expenses relate to decisions of the executive management group regarding corporate strategy, credit risk, loss contingencies and restructuring activities. Due to the non-operating nature of these decisions, the related charges have been separately presented and excluded from the results of specific segments. These charges are primarily related to the contract drilling segment.

(d) The Company's former CFO has pleaded guilty to criminal charges and has been sentenced and is serving a term of imprisonment arising out of his embezzlement of funds totaling approximately $77.5 million from the Company over a period of more than five years, ending November 3, 2005. Embezzlement costs, net of recoveries include embezzled funds and other costs incurred as a result of the embezzlement. In 2006, the Company recovered $2.0 million from its insurance carrier related to the embezzlement loss.

(e) Corporate assets primarily include cash on hand managed by the parent corporation and certain deferred Federal income tax assets.

16. Quarterly Financial Information (in thousands, except per share amounts) (unaudited)

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2006				
Operating revenues	$597,733	$636,813	$673,658	$638,382
Operating income	245,599	268,913	281,905	242,747
Net income	159,256	171,690	185,990	156,318
Net income per common share:				
Basic	$ 0.93	$ 1.02	$ 1.14	$ 0.99
Diluted	$ 0.91	$ 1.00	$ 1.12	$ 0.97
2005				
Operating revenues	$350,593	$389,922	$468,739	$531,201
Operating income	91,833	116,651	167,446	205,366
Net income	58,220	74,026	106,305	134,189
Net income per common share:				
Basic	$ 0.34	$ 0.44	$ 0.62	$ 0.78
Diluted	$ 0.34	$ 0.43	$ 0.61	$ 0.77

17. Concentrations of Credit Risk

Financial instruments, which potentially subject the Company to concentrations of credit risk, consist primarily of demand deposits, temporary cash investments and trade receivables.

The Company believes that it places its demand deposits and temporary cash investments with high credit quality financial institutions. At December 31, 2006 and 2005, the Company's demand deposits and temporary cash investments consisted of the following (in thousands):

	2006	2005
Deposits in FDIC and SIPC-insured institutions under $100,000	$ 684	$ 1,066
Deposits in FDIC and SIPC-insured institutions over $100,000	21,859	153,261
Deposits in Foreign Banks	3,754	2,513
	26,297	156,840
Less outstanding checks and other reconciling items	(12,912)	(20,442)
Cash and cash equivalents	$ 13,385	$136,398

Concentrations of credit risk with respect to trade receivables are primarily focused on companies involved in the exploration and development of oil and natural gas properties. The concentration is somewhat mitigated by the diversification of customers for which the Company provides drilling services. As is general industry practice, the Company typically does not require customers to provide collateral. No significant losses from individual customers were experienced during the years ended December 31, 2006, 2005, or 2004. The Company recognized bad debt expense for 2006, 2005 and 2004 of $5.4 million, $1.2 million and $897,000, respectively.

The carrying values of cash and cash equivalents, marketable securities, trade receivables and borrowings outstanding under the Company's line of credit approximate fair value due to the short-term maturity of these items.

18. Related Party Transactions

Joint Operation of Oil and Natural Gas Properties — The Company operates certain oil and natural gas properties in which certain of its affiliated persons have participated, either individually or through entities they control. These participations have typically been through working interests in prospects or properties originated or acquired by Patterson Petroleum LP, LLLP, a wholly owned subsidiary of Patterson-UTI. At December 31, 2006, affiliated persons were working interest owners in 281 of 330 total wells operated by Patterson-UTI. Sales of working interests to affiliated parties were made by Patterson-UTI at its cost, comprised of Patterson-UTI's costs of acquiring and preparing the working interests for sale plus a promote fee in some cases. These costs were paid by the working interest owners on a pro rata basis based upon their working interest ownership percentage. The price at which working interests were sold to affiliated persons was the same price at which working interests were sold to unaffiliated persons except that in some cases the affiliated persons also paid a promote fee. The affiliated persons earned oil and natural gas production revenue (net of royalty) of $15.8 million, $15.5 million and $13.8 million from these properties in 2006, 2005 and 2004, respectively. These persons or entities in turn paid for joint operating costs (including drilling and other development expenses) of $14.1 million, $9.5 million and $7.5 million incurred in 2006, 2005 and 2004, respectively. These activities resulted in a payable to the affiliated persons of approximately $1.5 million and $1.5 million and a receivable from the affiliated persons of approximately $1.6 million and $1.2 million at December 31, 2006 and 2005, respectively.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS

Description	Beginning Balance	Charged to Costs and Expenses(1)	Deductions(2)	Ending Balance
		(In thousands)		
Year Ended December 31, 2006				
Deducted from asset accounts:				
Allowance for doubtful accounts	$2,199	$5,400	$ 115	$7,484
Year Ended December 31, 2005				
Deducted from asset accounts:				
Allowance for doubtful accounts	$1,909	$1,231	$ 941	$2,199
Year Ended December 31, 2004				
Deducted from asset accounts:				
Allowance for doubtful accounts	$2,133	$ 897	$1,121	$1,909

(1) Net of recoveries.

(2) Uncollectible accounts written off.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Patterson-UTI Energy, Inc. has duly caused this Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized.

PATTERSON-UTI ENERGY, INC.

By: /s/ CLOYCE A. TALBOTT

Cloyce A. Talbott
President and Chief Executive Officer

Date: February 26, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report on Form 10-K has been signed by the following persons on behalf of Patterson-UTI Energy, Inc. and in the capacities indicated as of February 26, 2007.

Signature	Title
/s/ MARK S. SIEGEL Mark S. Siegel	Chairman of the Board
/s/ CLOYCE A. TALBOTT Cloyce A. Talbott *(Principal Executive Officer)*	President, Chief Executive Officer and Director
/s/ JOHN E. VOLLMER III John E. Vollmer III *(Principal Financial and Accounting Officer)*	Senior Vice President — Corporate Development, Chief Financial Officer and Treasurer
/s/ KENNETH N. BERNS Kenneth N. Berns	Senior Vice President and Director
/s/ ROBERT C. GIST Robert C. Gist	Director
/s/ CURTIS W. HUFF Curtis W. Huff	Director
/s/ TERRY H. HUNT Terry H. Hunt	Director
/s/ KENNETH R. PEAK Kenneth R. Peak	Director
Nadine C. Smith	Director

EXHIBIT 31.1

CERTIFICATIONS

I, Cloyce A. Talbott, certify that,

1. I have reviewed this annual report on Form 10-K of Patterson-UTI Energy, Inc.

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

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

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Cloyce A. Talbott

Cloyce A. Talbott
President and Chief Executive Officer

Date: February 26, 2007

EXHIBIT 31.2

CERTIFICATIONS

I, John E. Vollmer III, certify that:

1. I have reviewed this annual report on Form 10-K of Patterson-UTI Energy, Inc.

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

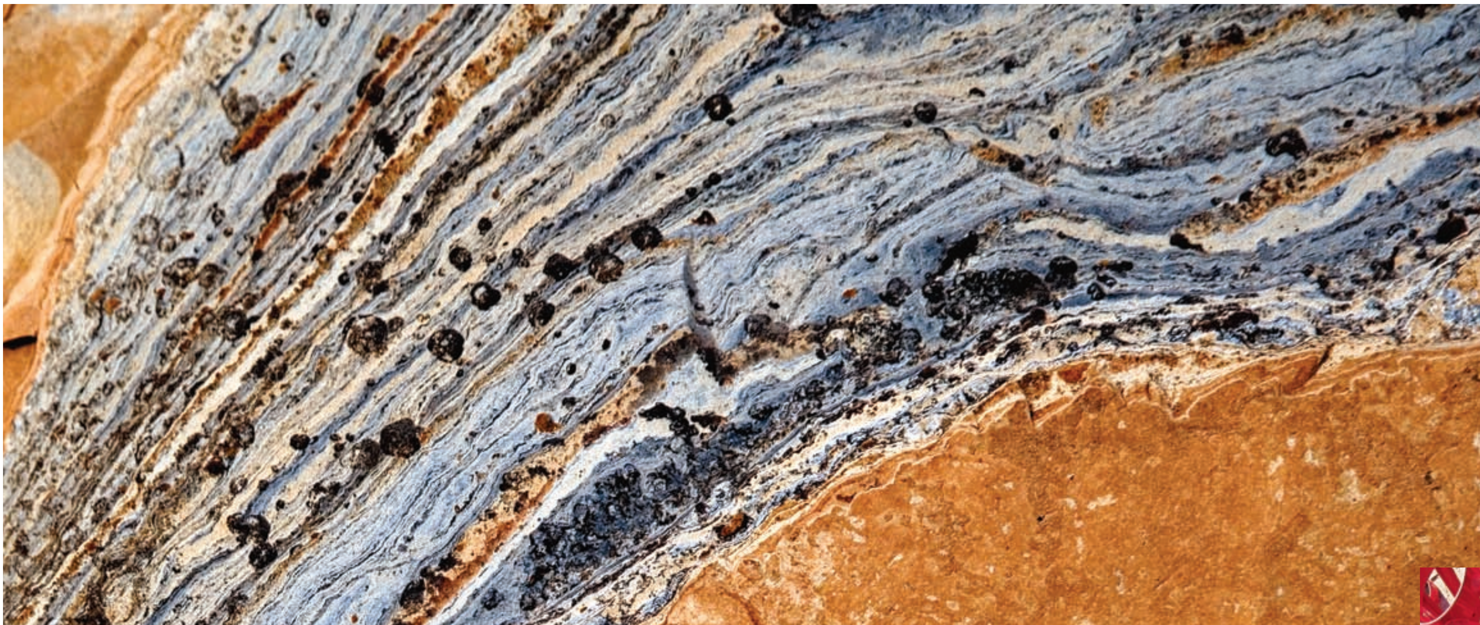
(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

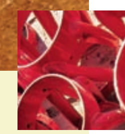
(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ JOHN E. VOLLMER III

John E. Vollmer III
Senior Vice President — Corporate Development,
Chief Financial Officer and Treasurer

Date: February 26, 2007





Corporate Information

Corporate Office

Patterson-UTI Energy, Inc.
P.O. Box 1416
Snyder, Texas 79550

4510 Lamesa Highway
Snyder, Texas 79549

Telephone: (325) 574-6300
Fax: (325) 574-6390
www.patenergy.com

Common Stock

Nasdaq: PTEN

Transfer Agent

Continental Stock
Transfer & Trust Company
17 Battery Place
New York, NY 10004
Toll-Free number:
(800) 509-5586
www.continentalstock.com

Independent Auditor

PricewaterhouseCoopers LLP

Corporate Counsel

Fulbright & Jaworski LLP

Directors

Mark S. Siegel
Chairman, Patterson-UTI Energy, Inc.;
President, Remy Investors and
Consultants, Incorporated

Cloyce A. Talbott
President and
Chief Executive Officer,
Patterson-UTI Energy, Inc.

Kenneth N. Berns
Senior Vice President,
Patterson-UTI Energy, Inc.

Charles O. Buckner
Retired Partner,
Ernst & Young LLP

Robert C. Gist
Attorney at Law

Curtis W. Huff
President and
Chief Executive Officer,
Freebird Investments LLC

Terry H. Hunt
Energy Consultant
and Investor

Kenneth R. Peak
President and
Chief Executive Officer,
Contango Oil & Gas

Nadine C. Smith
Business Consultant
and Investor

Corporate Officers

Mark S. Siegel
Chairman

Cloyce A. Talbott
President and
Chief Executive Officer

Douglas J. Wall
Chief Operating Officer

Kenneth N. Berns
Senior Vice President

John E. Vollmer III
Senior Vice President –
Corporate Development,
Chief Financial Officer
and Treasurer

William L. Moll, Jr.
General Counsel
and Secretary

PATTERSON-UTI ENERGY, INC.

PATTERSON-UTI ENERGY, INC.

Patterson-UTI Energy, Inc.
P.O. Box 1416
Snyder, Texas 79550

4510 Lamesa Highway
Snyder, Texas 79549

Telephone: (325) 574-6300
Fax: (325) 574-6390
www.patenergy.com