PATTERSON UTI ENERGY INC
Form 10-K
February 19, 2009

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

Form 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2008

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number 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.)*
450 Gears Road, Suite 500, Houston, Texas	**77067**
(Address of principal executive offices)	*(Zip Code)*

Registrant s telephone number, including area code:
(281) 765-7100

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

Preferred Share Purchase Rights

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

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 o or No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

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

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

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2008, the last business day of the registrant s most recently completed second fiscal quarter, was $5,581,179,402, calculated by reference to the closing price of $36.13 for the common stock on the Nasdaq National Market on that date.

As of February 16, 2009, the registrant had outstanding 153,098,601 shares of common stock, $.01 par value, its only class of common stock.

Documents incorporated by reference:

Definitive Proxy Statement for the 2009 Annual Meeting of Stockholders (Part III).

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FORWARD-LOOKING STATEMENTS AND CAUTIONARY STATEMENTS FOR PURPOSES OF THE SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

Certain statements made in this Annual Report on Form 10-K and in other public filings and press releases by us contain forward-looking information (as defined in the Private Securities Litigation Reform Act of 1995) that involves risk and uncertainty. These forward-looking statements include, without limitation, statements relating to: liquidity; financing of operations; continued volatility of oil and natural gas prices; source and sufficiency of funds required for immediate capital needs and additional rig acquisitions (if further opportunities arise); impact of inflation; and other matters. Our forward-looking statements can be identified by the fact that they do not relate strictly to historic or current facts and often use words such as believes, budgeted, expects, estimates, project, will, could, may intends, strategy, or anticipates, and other words and expressions of similar meaning. The forward-looking statements are based on certain assumptions and analyses we make in light of our experience and our perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate in the circumstances. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. Forward-looking statements may be made by management orally or in writing, including, but not limited to, Management s Discussion and Analysis of Financial Condition and Results of Operations included in this Annual Report on Form 10-K and other sections of our filings with the United States Securities and Exchange Commission (the SEC) under the Securities Exchange Act of 1934 and the Securities Act of 1933.

Forward-looking statements are not guarantees of future performance and a variety of factors could cause actual results to differ materially from the anticipated or expected results expressed in or suggested by these forward-looking statements. Factors that might cause or contribute to such differences include, but are not limited to, deterioration of global economic conditions, declines in oil and natural gas prices that could adversely affect demand for our services and their associated effect on day rates, rig utilization and planned capital expenditures, excess availability of land drilling rigs, including as a result of the reactivation or construction of new land drilling rigs, adverse industry conditions, adverse credit and equity market conditions, difficulty in integrating acquisitions, demand for oil and natural gas, shortages of rig equipment and ability to retain management and field personnel. Refer to Risk Factors contained in Part 1 of this Annual Report on Form 10-K for a more complete discussion of these and other factors that might affect our performance and financial results. These forward-looking statements are intended to relay our expectations about the future, and speak only as of the date they are made. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

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 SEC. The information contained on our website is not part of this Report or other filings that we make with the SEC. You may read and copy any materials we file with the SEC at the SEC s Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Overview

Based on publicly available information, we believe we are the second largest operator of land-based drilling rigs in the United States. The Company was formed in 1978 and reincorporated in 1993 as a Delaware corporation.

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Our contract drilling business operates primarily in Texas, New Mexico, Oklahoma, Arkansas, Louisiana, Mississippi, Alabama, Colorado, Arizona, Utah, Wyoming, Montana, North Dakota, South Dakota, Pennsylvania, West Virginia and western Canada.

As of December 31, 2008, we had a drilling fleet that consisted of 344 marketable land-based drilling rigs. A drilling rig includes the structure, power source and machinery necessary to cause a drill bit to penetrate the earth to a depth desired by the customer. A drilling rig is considered 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.

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, New Mexico, Oklahoma and Louisiana. Drilling and completion fluids are used by oil and natural gas operators to control pressure when drilling and completing oil and natural gas wells. We own and invest in oil and natural gas assets as a working interest owner. Our oil and natural gas interests are located primarily in Texas, New Mexico, Mississippi and Louisiana.

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 exploration and production.

All of our industry segments had operating profits in 2008, 2007 and 2006, except that in 2008 our drilling and completion fluids services segment reported an operating loss due to a non-cash charge recognized for the impairment of goodwill in that segment.

See Management s Discussion and Analysis of Financial Condition and Results of Operations and Note 14 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, 2008, we had 344 marketable land-based drilling rigs which were based in the following regions:

- 93 in west Texas and southeastern New Mexico,
- 92 in north central and eastern Texas, northern Louisiana, Mississippi and Alabama,
- 56 in the Rocky Mountain region (Colorado, Arizona, Utah, Wyoming, Montana, North Dakota and South Dakota),

50 in south Texas and southern Louisiana,

27 in the Texas panhandle, Oklahoma and Arkansas,

6 in the Appalachian Basin, and

20 in western Canada.

Our marketable drilling rigs have rated maximum depth capabilities ranging from 5,000 feet to 30,000 feet. Eighty seven of these drilling rigs are electric rigs and 257 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

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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, masts, pumps to circulate the drilling fluid, blowout preventers, drill pipe and other related equipment. Over time, components on a drilling rig are replaced or rebuilt. We spend significant funds each year as part of a program to modify, upgrade and maintain our drilling rigs to ensure that our drilling equipment is competitive. We have spent $1.4 billion during the last three years on capital expenditures to (1) build new land drilling rigs and (2) modify, upgrade and maintain our drilling fleet. During fiscal years 2008, 2007 and 2006, we spent approximately $361 million, $540 million and $531 million, respectively, on these capital expenditures.

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. Our rigs are capable of vertical or horizontal drilling.

Our contract drilling operations depend on the availability of drill pipe, drill bits, replacement parts and other related rig equipment, fuel and qualified personnel. Some of these 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. Our drilling contracts are either on a well-to-well basis or a term basis. Well-to-well contracts are generally short-term in nature and cover the drilling of a single well or a series of wells. Term contracts are entered into for a specified period of time (frequently one to three years) and provide for the use of the drilling rig to drill multiple wells. During 2008, our average number of days to drill a well (which includes moving to the drill site, rigging up and rigging down) was approximately 22 days.

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 and may or may not contain provisions for the payment of an early termination fee to us in the event that the contract is terminated by the customer. 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. Each drilling contract will contain the actual terms setting forth our rights and obligations and those of the particular customer.

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. All of our contracts during the years ended December 31, 2008, 2007 and 2006 provided for payment on a daywork basis. 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 often 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. All of our drilling contracts in 2006, 2007 and 2008 were daywork contracts.

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

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contractor than daywork contracts. Under footage contracts, the drilling contractor typically assumes certain risks associated with loss of the well from fire, blowouts and other risks. We did not enter into any footage contracts in the past three years.

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 typically 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. Given the increased exposure we have under a turnkey contract, however, 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. We did not enter into any turnkey contracts in the past three years.

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

	Year Ended December 31,		
	2008	**2007**	**2006**
Average rigs operating(1)	254	244	296
Number of rigs operated	315	338	331
Number of wells drilled	4,218	4,237	5,050
Number of operating days	93,068	89,095	108,221

(1) A rig is considered to be operating if it is earning revenue pursuant to a contract on a given day.

Drilling Rigs and Related Equipment We estimate the depth capacity with respect to our marketable rigs as of December 31, 2008 to be as follows:

	Number of Rigs		
Depth Rating (Ft.)	**U.S.**	**Canada**	**Total**
5,000 to 7,999		3	3
8,000 to 11,999	65	9	74
12,000 to 15,999	197	8	205
16,000 to 30,000	62		62
Totals	324	20	344

At December 31, 2008, we owned and operated 308 trucks and 405 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

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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, 2008 includes:

42 cement pumper trucks,

66 triplex pumper trucks,

54 nitrogen pumper trucks,

5 quintiplex pump trailers,

31 blender trucks,

28 bulk acid trucks/acid pumper trucks,

47 bulk cement trucks,

27 bulk nitrogen trucks,

6 bulk nitrogen tractor trailer combinations,

69 bulk sand trucks,

14 sand pneumatic trucks,

7 sand pneumatic trailers,

9 flatbed material trucks,

24 connection trucks,

2 shale fracturing manifold trailers,

1 shale fracturing iron trailer,

8 shale fracturing sand field bins with conveyors,

2 shale fracturing large conveyors, and

21 tractors.

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, New Mexico, Oklahoma and 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 fourteen 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 promote effective application of the products and systems used 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 The profitability of our drilling and completion fluids operations is affected by the availability and pricing 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 we have with producers of these raw materials.

Barite Grinding Facility We 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 own and operate 13 trucks and 141 trailers and lease another 34 trucks which are used to transport drilling and completion fluids and related equipment.

Oil and Natural Gas Operations

General We have been engaged in the development, exploration, acquisition and production of oil and natural gas. Through October 31, 2007, we served as operator with respect to several properties and were actively involved in the development, exploration, acquisition and production of oil and natural gas. Effective November 1, 2007, we sold the related operations portion of our exploration and production business, which was the portion of that business that actively managed the development, exploration, acquisition and production of oil and natural gas. We continue to own and invest in oil and natural gas assets as a working interest owner. Our oil and natural gas interests are located primarily in producing regions of Texas, New Mexico, Mississippi and Louisiana.

Customers

The customers of each of our three oil service business segments are oil and natural gas operators. Our customer base includes both major and independent oil and natural gas operators. During 2008, 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.

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. State and Federal environmental laws and regulations currently apply to our operations and may become more stringent in the future.

We believe 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

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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, cash flows 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 bodily injury and property damage to others with respect to our operations. Such insurance, however, 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 to cover physical damage to, or loss of, our drilling rigs. Such insurance does not, however, cover the full replacement cost of the rigs, and we do not carry insurance against loss of earnings resulting

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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, if obtained, may not be supported by adequate insurance maintained by the customer.

Employees

We had approximately 6,600 full-time employees at December 31, 2008. 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 drilling operations in Canada, and our pressure pumping division in the Appalachian Basin to a lesser extent, are subject to slow periods of activity during the Spring thaw.

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.***

You should consider each of the following factors as well as the other information in this Report in evaluating our business and our prospects. Additional risks and uncertainties not presently known to us or that we currently consider immaterial may also impair our business operations. If any of the following risks actually occur, our business and financial results could be harmed. You should also refer to the other information set forth in this Report, including our financial statements and the related notes.

Global Economic Conditions May Adversely Affect Our Operating Results.

During recent months, there has been a significant decline in oil and natural gas prices. During this time there has also been a significant deterioration in the global economic environment. As part of this deterioration, there has been significant uncertainty in the capital markets and access to financing has been reduced. As a result of these conditions, customers have recently started reducing or curtailing their drilling programs, which is resulting in a significant decrease in demand for our services. Furthermore, these factors could result in certain of our customers experiencing an inability to pay suppliers, including us, if they are not able to access capital to fund their operations. These conditions could have a material adverse effect on our business, financial condition, cash flows and results of operations.

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 Operating Results.

Our revenue, profitability and rate of growth are substantially dependent upon prevailing prices for natural gas and, to a lesser extent, oil. For many years, oil and natural gas prices and markets 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. During 2008, the monthly average market price of natural gas peaked in June at $13.06 per Mcf before rapidly declining to an average of $5.99 per Mcf in December. In January 2009, the average market price of natural gas declined further to $5.40 per Mcf. This decline in the market price of natural gas has resulted in our customers significantly reducing their drilling activities beginning in the fourth quarter of 2008 and continuing into 2009. This reduction in demand combined with the reactivation and construction of new land drilling rigs in the United States during the last several years has resulted in excess capacity compared to demand. As a result of these factors, our average number of rigs operating has recently declined significantly. We expect oil and natural gas prices to continue to be volatile and to affect our financial condition, operations and ability to access sources of capital. Continued low market prices for natural gas will likely result in further decreases in demand for our drilling rigs and adversely affect 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 declines in demand could have on us, ongoing factors which could continue to 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 in recent years, construction of new drilling rigs increased significantly. The addition of new drilling rigs to the market and the recent decrease in demand has resulted in excess capacity. 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 Oil Service Business Segments in Which We Operate Are Highly Competitive with Excess Capacity, which 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 and pressure pumping services, the industry experiences shortages of qualified personnel. During these periods, our ability to attract and retain sufficient qualified personnel to market and operate our drilling rigs and pressure pumping equipment 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 and pressure pumping equipment in response to the increased demand for such services. Additionally, wage rates for drilling and pressure pumping personnel are likely to increase during periods of increasing demand, 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, acquisitions and rig construction. 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 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 the cost of 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

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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.

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 Houston, Texas and include approximately 12,000 square feet of leased office space. These headquarters are located at 450 Gears Road, Suite 500, Houston, Texas, and our telephone number at that address is (281) 765-7100. Our primary administrative office is located in Snyder, Texas and includes approximately 37,000 square feet of office and storage space. We also have 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, New York, West Virginia, Kentucky, Tennessee, Wyoming and Colorado.

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 Working Interests Our interests in oil and natural gas properties are located in Texas, New Mexico, Mississippi and Louisiana.

We own our administrative offices 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.***

We are party to various 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 results of operations, cash flows or financial condition.

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

None.

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PART II

Item 5. *Market for Registrant s Common Equity, 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 indices. The following table provides high and low sales prices of our common stock for the periods indicated:

	High	Low
2007:		
First quarter	$ 24.89	$ 21.13
Second quarter	27.66	22.17
Third quarter	26.48	20.79
Fourth quarter	23.22	18.44
2008:		
First quarter	$ 26.38	$ 17.40
Second quarter	36.40	25.71
Third quarter	37.45	17.85
Fourth quarter	19.64	8.64

(b) Holders

As of February 16, 2009, there were approximately 2,300 holders of record of our common stock.

(c) Dividends and Buyback Program

We paid cash dividends during the years ended December 31, 2007 and 2008 as follows:

	Per Share	Total (In thousands)
2007:		
Paid on March 30, 2007	$ 0.08	$ 12,527
Paid on June 29, 2007	0.12	18,860
Paid on September 28, 2007	0.12	18,690
Paid on December 28, 2007	0.12	18,484
Total cash dividends	$ 0.44	$ 68,561
2008:		
Paid on March 28, 2008	$ 0.12	$ 18,493
Paid on June 27, 2008	0.16	25,011
Paid on September 29, 2008	0.16	24,803

Paid on December 29, 2008		0.16		24,558
Total cash dividends	$	0.60	$	92,865

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On February 11, 2009, our Board of Directors approved a cash dividend on our common stock in the amount of $0.05 per share to be paid on March 31, 2009 to holders of record as of March 12, 2009. The amount and timing of all future dividend payments, if any, 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, 2008.

Period covered	Total number of shares purchased		Average price paid per share	Total number of shares (or units) purchased as part of publicly announced plans or programs(1)		Approximate dollar value of shares that may yet be purchased under the plans or programs (In thousands)(1)
October 1 31, 2008		$			$	129,285
November 1 30, 2008	671,000	$	11.13	671,000	$	121,815
December 1 31, 2008	829,000	$	10.24	829,000	$	113,326
Total	1,500,000	$	10.64	1,500,000	$	113,326

(1) On August 2, 2007, we announced that our Board of Directors approved a stock buyback program authorizing purchases of up to $250 million of our common stock in open market or privately negotiated transactions.

(d) Securities Authorized for Issuance Under Equity Compensation Plans

Equity compensation plan information as of December 31, 2008 follows:

	Equity Compensation Plan Information		
	Number of Securities to be Issued upon Exercise of Outstanding Options,	Weighted-Average Exercise Price of Outstanding	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans (Excluding Securities Reflected in

Plan Category	**Warrants and Rights (a)**		**Options, Warrants and Rights (b)**	**Column(a)) (c)**
Equity compensation plans approved by security holders(1)	5,684,634	$	21.70	4,637,004
Equity compensation plans not approved by security holders(2)	248,938	$	9.94	
Total	5,933,572	$	21.20	4,637,004

(1) The Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan, as amended (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.

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(e) Performance Graph

The following graph compares the cumulative stockholder return of our common stock for the period from December 31, 2003 through December 31, 2008, with the cumulative total return of the Standard & Poors 500 Stock Index, the Standard & Poors MidCap Index, the Oilfield Service Index and a peer group determined by us. Our 2007 peer group consists of Grey Wolf, Inc., Helmerich & Payne, Inc., Nabors Industries, Ltd., Pioneer Drilling Co. and Unit Corp. We evaluated our peer group for 2008 and determined it was appropriate to add certain members. Our 2008 peer group consists of BJ Services Company, Bronco Drilling Company, Inc., Helmerich & Payne, Inc., Nabors Industries, Ltd., Pioneer Drilling Co., Precision Drilling Trust, Superior Well Services, Inc. and Unit Corp. Grey Wolf Inc. was acquired by Precision Drilling Trust in December 2008 and we have removed them from our 2008 peer group. All of the companies in our peer group are providers of land-based drilling and pressure pumping services. The graph assumes investment of $100 on December 31, 2003 and reinvestment of all dividends.

	Fiscal Year Ended December 31,					
Company/Index	**2003 ($)**	**2004 ($)**	**2005 ($)**	**2006 ($)**	**2007 ($)**	**2008 ($)**
Patterson-UTI Energy, Inc.	100.00	118.70	202.23	144.15	123.54	75.18
2007 Peer Group Index	100.00	129.84	198.24	160.02	166.05	69.51
2008 Peer Group Index	100.00	129.64	201.19	161.53	151.57	76.18
S&P 500 Stock Index	100.00	110.88	116.33	134.70	142.10	89.53
Oilfield Service Index (OSX)	100.00	135.32	202.85	231.52	339.83	138.31
S&P MidCap Index	100.00	116.48	131.11	144.64	156.18	99.59

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 Regulations 14A or 14C under the Exchange Act or to the liabilities of Section 18 under such Act.

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Item 6. *Selected Financial Data.*

Our selected consolidated financial data as of December 31, 2008, 2007, 2006, 2005 and 2004, and for each of the five years in the period ended December 31, 2008 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 2008 presentation.

	Years Ended December 31,				
	2008	2007	2006	2005	2004
	(In thousands, except per share amounts)				
Income Statement Data:					
Operating revenues:					
Contract drilling	$ 1,804,026	$ 1,741,647	$ 2,169,370	$ 1,485,684	$ 809,691
Pressure pumping	217,494	202,812	145,671	93,144	66,654
Drilling and completion fluids	145,246	128,098	192,358	122,011	90,557
Oil and natural gas	42,360	41,637	39,187	39,616	33,867
Total	2,209,126	2,114,194	2,546,586	1,740,455	1,000,769
Operating costs and expenses:					
Contract drilling	1,038,327	963,150	1,002,001	776,313	556,869
Pressure pumping	132,570	105,273	77,755	54,956	37,561
Drilling and completion fluids	126,900	108,752	150,372	98,530	76,503
Oil and natural gas	12,793	10,864	13,374	9,566	7,978
Goodwill impairment	9,964				
Depreciation, depletion and other impairment	268,431	249,206	196,370	156,393	122,800
Selling, general and administrative	68,190	64,623	55,065	39,110	31,983
Embezzlement costs (recoveries)		(43,955)	3,081	20,043	19,122
Net loss (gain) on asset disposals/retirements	6,071	(16,545)	3,819	(1,231)	(1,411)
Other operating expenses	4,350	2,550	5,585	5,479	897
Total	1,667,596	1,443,918	1,507,422	1,159,159	852,302
Operating income	541,530	670,276	1,039,164	581,296	148,467
Other income	1,418	531	4,670	3,463	680
Income before income taxes and cumulative effect of change in accounting principle	542,948	670,807	1,043,834	584,759	149,147
Income tax expense	195,879	232,168	371,267	212,019	54,801
Income before cumulative effect of change in accounting principle	347,069	438,639	672,567	372,740	94,346

Cumulative effect of change in accounting principle, net of related income tax expense of $398			687		
Net income	$ 347,069	$ 438,639	$ 673,254	$ 372,740	$ 94,346
Income before cumulative effect of change in accounting principle per common share:					
Basic	$ 2.26	$ 2.83	$ 4.07	$ 2.19	$ 0.57
Diluted	$ 2.24	$ 2.79	$ 4.02	$ 2.15	$ 0.56

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	Years Ended December 31,				
	2008	2007	2006	2005	2004
	(In thousands, except per share amounts)				
Net income per common share:					
Basic	$ 2.26	$ 2.83	$ 4.08	$ 2.19	$ 0.57
Diluted	$ 2.24	$ 2.79	$ 4.02	$ 2.15	$ 0.56
Cash dividends per common share	$ 0.60	$ 0.44	$ 0.28	$ 0.16	$ 0.06
Weighted average number of common shares outstanding:					
Basic	153,379	154,755	165,159	170,426	166,258
Diluted	154,717	156,997	167,413	173,767	169,211
Balance Sheet Data:					
Total assets	$ 2,712,817	$ 2,465,199	$ 2,192,503	$ 1,795,781	$ 1,256,785
Borrowings under line of credit		50,000	120,000		
Stockholders equity	2,126,942	1,896,030	1,562,466	1,367,011	961,501
Working capital	338,761	227,577	335,052	382,448	235,480

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

This Report, including 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 invest, on a working interest basis, in oil and natural gas properties. For the three years ended December 31, 2008, our operating revenues consisted of the following (dollars in thousands):

	2008		2007		2006	
Contract drilling	$ 1,804,026	82%	$ 1,741,647	82%	$ 2,169,370	84%
Pressure pumping	217,494	10	202,812	10	145,671	6
Drilling and completion fluids	145,246	6	128,098	6	192,358	8
Oil and natural gas	42,360	2	41,637	2	39,187	2
	$ 2,209,126	100%	$ 2,114,194	100%	$ 2,546,586	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, Alabama, Colorado, Arizona, Utah, Wyoming, Montana, North Dakota, South Dakota, Pennsylvania, West Virginia 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. The oil and natural gas properties in which we hold interests are primarily located in Texas, New Mexico, Mississippi and Louisiana.

Typically, 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 2008, our average number of rigs operating was 254 compared to 244 in 2007 and 296 in 2006. Our average revenue per operating day was $19,380 in 2008 compared to $19,550 in 2007 and $20,050 in 2006. Our consolidated net income for 2008 decreased by $91.6 million, or 21%, as compared to 2007. Included in consolidated net income for 2007 was a pre-tax gain of approximately $44.0 million associated with the recovery of embezzled funds. Excluding this recovery in 2007, our consolidated net income for 2007 would have been approximately $410 million and the decrease in net income for 2008 would have been approximately $62.8 million or 15%. The decrease in consolidated net income in 2008 was primarily due to our contract drilling segment experiencing a decrease in operating income of $27.8 million driven by a decrease in average revenue per operating day and an increase in average costs per operating day; our pressure pumping segment experiencing a decrease in operating income of $22.2 million driven by an increase in average direct operating costs per job; the recognition of an impairment of goodwill in the amount of $9.964 million in our drilling and completion fluids segment; and losses incurred on the disposal and retirement of assets in 2008 of $6.1 million as compared to a gain on disposal of assets in 2007 of $16.5 million.

Our revenues, profitability and cash flows are highly dependent upon prevailing prices for natural gas and, to a lesser extent, oil. During periods of improved commodity prices, the capital spending budgets of oil and natural gas operators tend to expand, which generally results in increased demand for our contract services. Conversely, in periods when these commodity prices deteriorate, the demand for our contract services generally weakens and we experience downward pressure on pricing for our services. During recent months, there has been a significant decline in oil and natural gas prices. During this time there has also been a substantial deterioration in the global economic environment. As part of this deterioration, there has been substantial uncertainty in the capital markets and access to financing has been reduced. Due to these conditions, customers have recently started reducing or curtailing their drilling programs, which is resulting in a decrease in demand for our services, as evidenced by the decline in our monthly average rigs operating from 283 in October 2008 to 162 in January 2009. Furthermore, these factors could result in certain of our customers experiencing an inability to pay suppliers, including us, if they are not able to access capital to fund their operations. We are also highly impacted by competition, the availability of excess equipment, labor issues and various other factors that could materially adversely affect our business, financial condition, cash flows and results of operations which are more fully described as Risk Factors in Item 1A of this Report.

We believe that the liquidity shown on our balance sheet as of December 31, 2008, which includes approximately $339 million in working capital (including $81.2 million in cash) and approximately $316.5 million currently available under our current $375 million revolving line of credit, together with cash expected to be generated from operations, provides us with sufficient ability to fund our 2009 plans to build new equipment, make improvements to our existing equipment, expand into new regions, pay cash dividends and survive the current downturn in our industry.

Commitments and Contingencies We maintain letters of credit in the aggregate amount of $58.5 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 and are typically renewed annually. As of December 31, 2008, no amounts had been drawn under the letters of credit.

As of December 31, 2008, we had commitments to purchase approximately $269 million of major equipment.

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 and money market accounts.

Description of business We conduct our contract drilling operations in Texas, New Mexico, Oklahoma, Arkansas, Louisiana, Mississippi, Alabama, Colorado, Arizona, Utah, Wyoming, Montana, North Dakota, South Dakota, Pennsylvania, West Virginia and western Canada. For the years ended December 31, 2008, 2007 and 2006, revenue earned outside of the United States was $88.5 million, $72.9 million and $98.5 million, respectively. Additionally, we had long-lived assets located outside of the United States of $67.2 million and $91.6 million as of December 31, 2008 and 2007, respectively. As of December 31, 2008, we had 344 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, New Mexico, Oklahoma and 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 also invest, on a working interest basis, in oil and natural gas properties.

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 long-lived assets, including property and equipment, for impairment when events or changes in circumstances indicate that the carrying values of certain assets may not be recovered over their estimated remaining useful lives. In connection with this review, assets are grouped at the lowest level at which identifiable cash flows are largely independent of other asset groupings. 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

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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 against income when estimated future cash flows, on an undiscounted basis, are less than the asset s net book value. Any provision for impairment is measured based on discounted cash flows.

During 2008, we evaluated our fleet of marketable drilling rigs and identified 22 rigs that we determined would no longer be marketed as rigs. The components which made up these rigs were evaluated, and those components with continuing utility to our other marketed rigs (with a net book value of $13.4 million) were transferred to our yards to be used as spare equipment. The remaining components of these rigs were retired and the associated net book value of $10.4 million was expensed in our statement of operations as a component of net loss (gain) on asset disposals/retirements .

In the fourth quarter of 2008, we experienced a significant decrease in the number of our rigs operating and oil and natural gas prices decreased significantly. These events were deemed by us to be triggering events that required us to perform an assessment with respect to impairment of long-lived assets, including property and equipment, in our contract drilling, drilling and completion fluids and oil and natural gas segments. With respect to the long-lived assets in our contract drilling and drilling and completion fluids segments, we estimated future cash flows over the expected life of the long-lived assets, which were comprised primarily of property and equipment, and determined that, on an undiscounted basis, expected cash flows exceeded the carrying value of the long-lived assets. Based on this assessment, no impairment was indicated. Impairment considerations in our oil and natural gas segment related to proved properties are discussed below. No triggering event has occurred with respect to our pressure pumping segment as the level of activity and revenue growth in that segment has not been impacted to the same degree as in our other segments. There were no material impairment charges related to property and equipment during the years 2008, 2007 or 2006.

Oil and natural gas properties Working interests in 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 a triggering 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 based on our expectation of future pricing over the lives of the respective fields. These estimates are then 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 assess potential impairment. The 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 $4.4 million, $3.9 million and $5.0 million for the years ended December 31, 2008, 2007 and 2006, 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 as of December 31 or on an interim basis if events or circumstances

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indicate that the fair value of the asset has decreased below its carrying value. Goodwill impairment testing is performed at the level of our reporting units. Our reporting units have been determined to be the same as our operating segments. The contract drilling segment and drilling and completion fluids segments are the reporting units of the Company that have goodwill. In connection with our annual assessment of potential impairment of goodwill, we compare the fair value of the reporting units with their carrying value. If the fair value exceeds the carrying value, no impairment is indicated. If the carrying value exceeds the fair value, we measure any impairment of goodwill in that reporting unit by allocating the fair value to the identifiable assets and liabilities of the reporting unit based on their respective fair values. Any excess un-allocated fair value would equal the implied fair value of goodwill, and if that amount is below the carrying value of goodwill, an impairment charge is recognized.

In connection with our annual goodwill impairment assessment performed as of December 31, 2008, we performed an impairment test of our contract drilling and drilling and completion fluids reporting units. In light of the adverse market conditions affecting our common stock price beginning in the fourth quarter of 2008 and continuing into 2009, including a significant decrease in the number of our rigs operating and a significant decline in oil and natural gas commodity prices, we utilized a discounted cash flow methodology to estimate the fair values of our reporting units. In completing the first step of our analysis, we used a three-year projection of discounted cash flows, plus a terminal value determined using the constant growth method to estimate the fair value of our reporting units. In developing these fair value estimates, certain key assumptions included an assumed discount rate of 13.99% for all reporting units, an assumed long-term growth rate of 3.50% for the contract drilling reporting unit and an assumed long-term growth rate of 2.00% for the drilling and completion fluids reporting unit.

Based on the results of the first step of the impairment test, we concluded that no impairment was indicated in the contract drilling reporting unit; however, an impairment was indicated in our drilling and completion fluids reporting unit. In validating this conclusion, we considered the results of our long-lived asset impairment tests and performed sensitivity analyses of the key assumptions used in deriving the respective fair values of our reporting units. We performed the second step of the analysis of our drilling and completion fluids reporting unit, allocating the estimated fair value to the identifiable tangible and intangible assets and liabilities of this reporting unit based on their respective values. This allocation indicated no residual value for goodwill, and accordingly we recorded an impairment charge of $9.964 million in our December 31 2008 statement of operations.

In the event that market conditions continue to deteriorate, we may be required to record an impairment of goodwill in our contract drilling reporting unit in the future and such impairment may be material.

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. 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 total revenues. We recognize reimbursements received from third parties for out-of-pocket expenses incurred as revenues and account for these out-of-pocket expenses as direct costs. We did not enter into any footage or turnkey contracts in the past three years.

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,
- depreciation and depletion,

goodwill and long-lived asset impairments,

reserves for self-insured levels of insurance coverage, and

fair values of assets acquired 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.

Liquidity and Capital Resources

As of December 31, 2008, we had working capital of $339 million, including cash and cash equivalents of $81.2 million. During 2008, our sources of cash flow included:

$675 million from operating activities,

$11.6 million in proceeds from the disposal of property and equipment, and

$41.8 million from the exercise of stock options and related tax benefits associated with stock-based compensation.

During 2008, we used $92.9 million to pay dividends on our common stock, $70.8 million to repurchase shares of our common stock, $50.0 million to repay borrowings under our line of credit and $449 million:

to build new drilling rigs,

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 segments, and

to fund investments in oil and natural gas properties on a working interest basis.

We paid cash dividends during the year ended December 31, 2008 as follows:

	Per Share	Total (In thousands)
Paid on March 28, 2008	$ 0.12	$ 18,493
Paid on June 27, 2008	0.16	25,011
Paid on September 29, 2008	0.16	24,803
Paid on December 29, 2008	0.16	24,558
Total cash dividends	$ 0.60	$ 92,865

On February 11, 2009, our Board of Directors approved a cash dividend on our common stock in the amount of $0.05 per share to be paid on March 31, 2009 to holders of record as of March 12, 2009. The amount and timing of all future dividend payments, if any, 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 August 1, 2007, our Board of Directors approved a stock buyback program (2007 Program), authorizing purchases of up to $250 million of our common stock in open market or privately negotiated transactions. During the year ended December 31, 2007, we purchased 3,308,850 shares of our common stock under the 2007 Program at a cost of approximately $70.4 million. During the year ended December 31, 2008, we purchased 3,502,047 shares of our common stock under the 2007 Program at a cost of approximately $66.3 million. As of December 31, 2008, we are authorized to purchase approximately $113 million of our outstanding common stock under the 2007 Program.

We have an unsecured revolving line of credit with a maximum borrowing capacity of $375 million which expires on December 16, 2009. Interest is paid on outstanding balances at a floating rate ranging from LIBOR plus 0.625% to 1.0% or the prime rate at our election. We are currently in the process of evaluating our alternative courses of action with respect to the upcoming maturity of this revolving line of credit. There can be no assurance that we will be able to renew or replace the existing revolving line of credit with similar terms, if at all. As of

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December 31, 2008, we had no borrowings outstanding under our $375 million revolving line of credit. We had $58.5 million in letters of credit outstanding under the revolving line of credit at December 31, 2008, and as a result we had available borrowing capacity of approximately $316.5 million at such date.

We believe that the current level of cash, short-term investments and borrowing capacity available under our current revolving line of credit, together with cash expected to be generated from operations, should be sufficient to meet our 2009 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 or additional debt or equity financing. However, there can be no assurance that additional capital will be available on reasonable terms, if at all.

Contractual Obligations

The following table presents information with respect to our contractual obligations as of December 31, 2008 (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)	$	$	$	$	$
Commitments to purchase equipment(2)	268,934	162,052	106,882		
	$ 268,934	$ 162,052	$ 106,882	$	$

(1) No borrowings were outstanding on our revolving line of credit as of December 31, 2008. Our revolving line of credit matures on December 16, 2009.

(2) Represents commitments to purchase major equipment to be delivered in 2009 and 2010 based on expected delivery dates.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements at December 31, 2008.

Results of Operations

Comparison of the years ended December 31, 2008 and 2007

The following tables summarize operations by business segment for the years ended December 31, 2008 and 2007:

	Year Ended December 31,		
Contract Drilling	**2008**	**2007**	**% Change**

	(Dollars in thousands)		
Revenues	$ 1,804,026	$ 1,741,647	3.6%
Direct operating costs	$ 1,038,327	$ 963,150	7.8%
Selling, general and administrative	$ 5,363	$ 5,893	(9.0)%
Depreciation	$ 229,311	$ 213,812	7.2%
Operating income	$ 531,025	$ 558,792	(5.0)%
Operating days	93,068	89,095	4.5%
Average revenue per operating day	$ 19.38	$ 19.55	(0.9)%
Average direct operating costs per operating day	$ 11.16	$ 10.81	3.2%
Average rigs operating	254	244	4.1%
Capital expenditures	$ 360,645	$ 539,506	(33.2)%

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The demand for our contract drilling services is impacted by the market price of natural gas and, to a lesser extent, oil. The reactivation and construction of new land drilling rigs in the United States in recent years has also contributed to an excess capacity of land drilling rigs compared to demand. The average market price of natural gas for each of the fiscal quarters and full years in 2008 and 2007 follow:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year
2007:					
Average natural gas price(1)	$ 7.44	$ 7.76	$ 6.35	$ 7.19	$ 7.18
2008:					
Average natural gas price(1)	$ 8.92	$ 11.74	$ 9.28	$ 6.60	$ 9.13

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

Revenues and direct operating costs increased in 2008 compared to 2007 primarily as a result of an increase in the number of operating days. The increase in operating days was due to increased demand caused by higher prices for natural gas during most of 2008 compared to 2007. Average revenue per operating day in 2008 was relatively flat compared to 2007. Average direct operating costs per operating day increased in 2008 due to incremental costs incurred to activate idle drilling rigs as well as increases in labor, repairs and other related costs. Significant capital expenditures have been incurred to build new 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	**2008**	**2007**	**% Change**
	(Dollars in thousands)		
Revenues	$ 217,494	$ 202,812	7.2%
Direct operating costs	$ 132,570	$ 105,273	25.9%
Selling, general and administrative	$ 23,305	$ 18,971	22.8%
Depreciation	$ 19,600	$ 14,311	37.0%
Operating income	$ 42,019	$ 64,257	(34.6)%
Total jobs	12,900	14,094	(8.5)%
Average revenue per job	$ 16.86	$ 14.39	17.2%
Average direct operating costs per job	$ 10.28	$ 7.47	37.6%
Capital expenditures	$ 61,289	$ 47,582	28.8%

In 2008, our customers increased their focus on the emerging development of unconventional reservoirs in the Appalachian Basin and the larger jobs associated therewith. As a result of this focus on unconventional reservoirs, we experienced a decrease in smaller traditional pressure pumping jobs, which resulted in an overall decrease in the number of total jobs. Revenues and direct operating costs increased as a result of an increase in the average revenue and average direct operating costs per job. Increased average revenue per job was due to an increase in larger jobs being driven by demand for services associated with unconventional reservoirs as discussed above. Average direct operating costs per job increased as a result of increases in compensation, maintenance and the cost of materials used in our operations, as well as an increase in larger jobs, which require significantly more materials to complete. In anticipation of increased activity associated with the unconventional reservoirs in the Appalachian Basin, we have added facilities, equipment and personnel over the past two years. Delays in the development of these reservoirs have caused a slower increase in customer activity than we had expected, negatively impacting the profitability of this business. Selling, general and administrative expense increased primarily as a result of expenses to support the expanding operations of this segment. Significant capital expenditures have been incurred to add capacity, expand our areas of operation and modify and upgrade existing equipment. The increase in depreciation expense is a result of the capital expenditures discussed above.

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Drilling and Completion Fluids	Year Ended December 31, 2008	2007	% Change
	(Dollars in thousands)		
Revenues	$ 145,246	$ 128,098	13.4%
Direct operating costs	$ 126,900	$ 108,752	16.7%
Selling, general and administrative	$ 10,110	$ 9,958	1.5%
Depreciation	$ 2,830	$ 2,860	(1.0)%
Goodwill impairment	$ 9,964	$	N/A%
Operating income (loss)	$ (4,558)	$ 6,528	N/A%
Capital expenditures	$ 3,467	$ 3,082	12.5%

Revenues increased in 2008 compared to 2007 due to increased sales both on land and offshore in the Gulf of Mexico, as well as increased pricing for certain products. Direct operating costs increased due to increased sales as well as increases in the cost of raw materials, including barite ore. Direct operating costs in 2008 also include approximately $940,000 in losses associated with damage suffered as a result of hurricanes. Direct operating costs in 2007 include a reduction of approximately $1.9 million related to a recovery received on an insurance claim. In connection with our annual assessment of the potential impairment of goodwill as of December 31, 2008, we estimated the fair value of our drilling and completion fluids reporting unit based on discounted expected cash flows. Based on this assessment we determined that all goodwill of this reporting unit was impaired and a charge was recognized in the fourth quarter of 2008. No impairment of goodwill was indicated in our previous annual assessment as of December 31, 2007. As of December 31, 2008, our drilling and completion fluids segment has no remaining goodwill.

Oil and Natural Gas Production and Exploration	Year Ended December 31, 2008	2007	% Change
	(Dollars in thousands, except commodity prices)		
Revenues	$ 42,360	$ 41,637	1.7%
Direct operating costs	$ 12,793	$ 10,864	17.8%
Selling, general and administrative	$	$ 2,365	(100.0)%
Depreciation, depletion and impairment	$ 15,856	$ 17,410	(8.9)%
Operating income	$ 13,711	$ 10,998	24.7%
Capital expenditures	$ 22,981	$ 17,516	31.2%
Average net daily oil production (Bbls)	801	971	(17.5)%
Average net daily gas production (Mcf)	3,755	4,996	(24.8)%
Average oil sales price (per Bbl)	$ 98.70	$ 68.82	43.4%
Average gas sales price (per Mcf)	$ 9.77	$ 7.37	32.6%

Revenues increased due to higher average sales prices of oil and natural gas. This increase was partially offset by a decrease in the average net daily production of oil and natural gas and by the elimination of well operations revenue due to the sale in the fourth quarter of 2007 of the operating responsibilities associated with oil and natural gas wells. Average net daily oil and natural gas production decreased primarily due to the sale of properties in 2007 and production declines. Direct operating costs increased due to an increase in seismic expenses as well as increased production taxes and other production costs. Selling, general and administrative expense decreased in 2008 due to the sale of the operating responsibilities mentioned above and the resulting elimination of headcount in this segment. Depreciation, depletion and impairment expense in 2008 includes approximately $4.4 million incurred to impair certain oil and natural gas properties compared to approximately $3.9 million incurred to impair certain oil and natural gas properties in 2007. Depletion expense decreased approximately $1.9 million primarily due to the sale of certain properties in 2007.

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Corporate and Other	Year Ended December 31, 2008	2007	% Change
	(Dollars in thousands)		
Selling, general and administrative	$ 29,412	$ 27,436	7.2%
Depreciation	$ 834	$ 813	2.6%
Other operating expenses	$ 4,350	$ 2,550	70.6%
Embezzlement recoveries	$	$ (43,955)	(100.0)%
Net loss (gain) on asset disposals/retirements	$ 6,071	$ (16,545)	N/A%
Interest income	$ 1,555	$ 2,355	(34.0)%
Interest expense	$ 639	$ 2,187	(70.8)%
Other income	$ 502	$ 363	38.3%
Capital expenditures	$ 511	$	N/A%

Selling, general and administrative expense increased primarily as a result of additional compensation expense and an increase in payroll tax expense associated with the exercise of stock options during 2008. Other operating expenses increased due to an increase in bad debt expense of $1.8 million. In 2008, we retired 22 drilling rigs out of our fleet and transferred usable components with a net book value of $13.4 million to our yards to be used as spare equipment. Losses on the retirement of components that were not transferred to the yards were approximately $10.4 million, and we recognized gains on the disposal of other assets of approximately $4.3 million in 2008. In 2007, we sold certain oil and natural gas properties resulting in a gain of $21.6 million which was partially offset by approximately $5.1 million in losses associated with the disposal of other assets. Gains and losses on the disposal or retirement of assets are considered as part of our corporate activities because such transactions relate to decisions of our executive management regarding corporate strategy.

In November 2005, we discovered that our former Chief Financial Officer, Jonathan D. Nelson (Nelson), had fraudulently diverted approximately $77.5 million in Company funds for his own benefit during the period from 1998 through 2005. 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 was appointed to take control of and liquidate the assets of Nelson. In May 2007, the court approved a plan of distribution for the assets recovered by the receiver. We recovered a total of approximately $44.5 million pursuant to the approved plan, and we recognized this recovery in our consolidated statement of income in 2007, net of professional fees incurred as a result of the embezzlement.

Comparison of the years ended December 31, 2007 and 2006

The following tables summarize operations by business segment for the years ended December 31, 2007 and 2006:

Contract Drilling	Year Ended December 31, 2007	2006	% Change
	(Dollars in thousands)		
Revenues	$ 1,741,647	$ 2,169,370	(19.7)%
Direct operating costs	$ 963,150	$ 1,002,001	(3.9)%
Selling, general and administrative	$ 5,893	$ 7,313	(19.4)%
Depreciation	$ 213,812	$ 168,607	26.8%

Operating income	$	558,792	$	991,449	(43.6)%
Operating days		89,095		108,192	(17.7)%
Average revenue per operating day	$	19.55	$	20.05	(2.5)%
Average direct operating costs per operating day	$	10.81	$	9.26	16.7%
Average rigs operating		244		296	(17.6)%
Capital expenditures	$	539,506	$	531,087	1.6%

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The demand for our contract drilling services is impacted by the market price of natural gas and, to a lesser extent, oil. The reactivation and construction of new land drilling rigs in the United States in recent years has also contributed to excess capacity compared to demand. Additionally, drilling activity in Canada decreased significantly in 2007 compared to 2006. As a result, our average rigs operating declined to 244 in 2007 from 296 in 2006. The average market price of natural gas for each of the fiscal quarters and full years in 2007 and 2006 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
2007:					
Average natural gas price(1)	$ 7.44	$ 7.76	$ 6.35	$ 7.19	$ 7.18

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

Revenues in 2007 decreased as compared to 2006 as a result of decreases in the number of operating days and in the average revenues per operating day. Direct operating costs in 2007 decreased as compared to 2006 as a result of the decreased number of operating days, largely offset by an increase in the average direct operating costs per operating day. The increase in average direct operating costs per day resulted primarily from increased compensation costs and an increase in the cost of maintenance for our drilling rigs. Operating days, average rigs operating and average revenue per operating day decreased in 2007 as a result of decreased demand for our contract drilling services resulting from the excess capacity discussed above. Selling, general and administrative expense decreased primarily as a result of the transfer of certain administrative staff to our corporate segment. Significant capital expenditures have been incurred in both 2007 and 2006 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 is a result of the capital expenditures discussed above.

Pressure Pumping	**Year Ended December 31, 2007**	**2006**	**% Change**
	(Dollars in thousands)		
Revenues	$ 202,812	$ 145,671	39.2%
Direct operating costs	$ 105,273	$ 77,755	35.4%
Selling, general and administrative	$ 18,971	$ 13,185	43.9%
Depreciation	$ 14,311	$ 9,896	44.6%
Operating income	$ 64,257	$ 44,835	43.3%
Total jobs	14,094	11,650	21.0%
Average revenue per job	$ 14.39	$ 12.50	15.1%
Average direct operating costs per job	$ 7.47	$ 6.67	12.0%
Capital expenditures	$ 47,582	$ 41,262	15.3%

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 was attributable to increased demand for our services and increased operating capacity. Increased average revenue per job was due to increased pricing for our services and an increase in the number of larger jobs being driven by demand for services associated with unconventional reservoirs in the Appalachian basin. Average direct operating costs per job increased as a result of increases in compensation, maintenance 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 primarily as a result of expenses to support the expanding operations of the pressure pumping segment. Significant capital expenditures have been incurred in both 2007 and 2006 to add capacity, expand our areas of operation and modify and upgrade existing equipment. The increase in depreciation expense is a result of the capital expenditures discussed above.

Drilling and Completion Fluids	Year Ended December 31, 2007	2006	% Change
	(Dollars in thousands)		
Revenues	$ 128,098	$ 192,358	(33.4)%
Direct operating costs	$ 108,752	$ 150,372	(27.7)%
Selling, general and administrative	$ 9,958	$ 10,521	(5.4)%
Depreciation	$ 2,860	$ 2,706	5.7%
Operating income	$ 6,528	$ 28,759	(77.3)%
Capital expenditures	$ 3,082	$ 4,222	(27.0)%

Revenues and direct operating costs decreased as a result of a decrease in the number of large jobs offshore in the Gulf of Mexico caused primarily by a slowdown in drilling activity during 2007 as compared to 2006.

Oil and Natural Gas Production and Exploration	Year Ended December 31, 2007	2006	% Change
	(Dollars in thousands, except commodity prices)		
Revenues	$ 41,637	$ 39,187	6.3%
Direct operating costs	$ 10,864	$ 13,374	(18.8)%
Selling, general and administrative	$ 2,365	$ 2,785	(15.1)%
Depreciation, depletion and impairment	$ 17,410	$ 14,368	21.2%
Operating income	$ 10,998	$ 8,660	27.0%
Capital expenditures	$ 17,516	$ 21,198	(17.4)%
Average net daily oil production (Bbls)	971	983	(1.2)%
Average net daily gas production (Mcf)	4,996	5,143	(2.9)%
Average oil sales price (per Bbl)	$ 68.82	$ 63.83	7.8%
Average gas sales price (per Mcf)	$ 7.37	$ 6.82	8.1%

Revenues increased due to an increase in the average sales price of both oil and natural gas in 2007 compared to 2006. Average net daily oil and natural gas production decreased in 2007 primarily due to the sale of certain properties in the first half of 2007. The decrease in direct operating costs is primarily due to a decrease of approximately $3.0 million in costs associated with the abandonment of exploratory wells in 2007 compared to 2006. Selling, general and administrative expenses decreased in 2007 primarily due to the transfer in the fourth quarter of the operating responsibilities associated with oil and natural gas wells resulting in reduced headcount in our oil and natural gas production and exploration segment. Depreciation, depletion and impairment expense in 2007 includes approximately $3.9 million incurred to impair certain oil and natural gas properties compared to approximately $5.0 million incurred to impair certain oil and natural gas properties in 2006. Depletion expense increased approximately $4.2 million primarily due to the completion of new wells in 2007.

Corporate and Other	Year Ended December 31, 2007	2006	% Change
	(Dollars in thousands)		

Selling, general and administrative	$ 27,436	$ 21,261	29.0%
Depreciation	$ 813	$ 793	2.5%
Other operating expenses	$ 2,550	$ 5,585	(54.3)%
Embezzlement costs (recoveries)	$ (43,955)	$ 3,081	N/A%
Net loss (gain) on asset disposals/retirements	$ (16,545)	$ 3,819	N/A%
Interest income	$ 2,355	$ 5,925	(60.3)%
Interest expense	$ 2,187	$ 1,602	36.5%
Other income	$ 363	$ 347	4.6%
Capital expenditures	$	$ 150	(100.0)%

Selling, general and administrative expense increased primarily as a result of compensation expense related to transfers of certain administrative staff from our drilling segment to our corporate segment as well as increases in stock-based compensation expense. Other operating expenses decreased due to a decrease in bad debt expense of $2.9 million. In 2007, we sold certain oil and natural gas properties resulting in a gain of $21.6 million This gain was reduced by approximately $5.1 million in losses associated with the disposal of other assets. Gains and losses on the disposal or retirement of assets are considered as part of our corporate activities due to the fact that such transactions relate to decisions of the executive management group regarding corporate strategy. Embezzlement costs (recoveries) in 2007 includes a recovery of $44.5 million reduced by professional fees incurred as a result of the embezzlement involving our former Chief Financial Officer. Embezzlement costs (recoveries) in 2006 include professional fees incurred as a result of the embezzlement reduced by insurance proceeds of $2.3 million.

Income Taxes

	Year Ended December 31,		
	2008	2007	2006
	(Dollars in thousands)		
Income before income tax	$ 542,948	$ 670,807	$ 1,043,834
Income tax expense	195,879	232,168	371,267
Effective tax rate	36.1%	34.6%	35.6%

The effective tax rate is a result of a Federal rate of 35.0% adjusted as follows:

	2008	2007	2006
Statutory tax rate	35.0%	35.0%	35.0%
State income taxes	1.7	1.4	1.4
Permanent differences	(0.4)	(1.6)	(0.8)
Other, net	(0.2)	(0.2)	0.0
Effective tax rate	36.1%	34.6%	35.6%

The permanent differences indicated above are largely attributable to our Domestic Production Activities deduction, partially offset in 2008 by the non-deductible goodwill impairment recognized in our drilling and completion fluids segment. The Domestic Production Activities Deduction was enacted as part of the American Jobs Creation Act of 2004 (as revised by the Emergency Economic Stabilization Act of 2008, the Act) and is effective for taxable years after December 31, 2004. The Act allows a deduction of 3% in 2006 and 6% in both 2007 and 2008 on the lesser of qualified production activities income or taxable income.

We record deferred Federal income taxes based primarily on the temporary differences between the book and tax bases of 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 expense of approximately $66.0 million in 2008, $38.3 million in 2007 and a deferred tax benefit of approximately $4.1 million in 2006.

Volatility of Oil and Natural Gas Prices and its Impact on Operations

Our revenue, profitability, and rate of growth are substantially dependent upon prevailing prices for natural gas and, to a lesser extent, oil. For many years, oil and natural gas prices and markets have been extremely 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. During 2008, the monthly average market price of natural gas peaked in June at $13.06 per Mcf before rapidly declining to an average of $5.99 per Mcf in December. In January 2009, the average market price of natural gas declined further to $5.40 per Mcf. This has resulted in our customers significantly reducing their drilling activities beginning in the fourth quarter of 2008 and continuing into 2009. This reduction in demand combined with the reactivation and construction of new land drilling rigs in the United States during the last several years has resulted in excess capacity compared to demand. As a result of these factors, our average number of rigs operating has recently declined significantly. We expect oil and natural gas prices to continue to be volatile and to affect our

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financial condition, operations and ability to access sources of capital. Continued low market prices for natural gas will likely result in further decreases in demand for our drilling rigs and adversely affect our operating results.

The North American land drilling industry has experienced 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

Inflation has not had a significant impact on our operations during the three years in the period ended December 31, 2008. We believe that inflation will not have a significant near-term impact on our financial position.

Recently Issued Accounting Standards

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. The initial application of FAS 157 is limited to financial assets and liabilities and became effective on January 1, 2008 for us. The impact of the initial application of FAS 157 was not material. On January 1, 2009, we adopted FAS 157 on a prospective basis for non-financial assets and liabilities that are not measured at fair value on a recurring basis. The application of FAS 157 to our non-financial assets and liabilities will primarily be limited to assets acquired and liabilities assumed in a business combination, asset retirement obligations and asset impairments, including goodwill and long-lived assets. This application of FAS 157 is not expected to have a material impact to us.

In December 2007, the FASB issued Statement No. 141(R), *Business Combinations* (FAS 141(R)) and Statement No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51* (FAS 160). FAS 141(R) is a revision of Statement No. 141, *Business Combinations*, and calls for significant changes from current practice in accounting for business combinations. FAS 141(R) is effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. FAS 160 amends ARB 51 to establish accounting and reporting standards for the non-controlling interest in a subsidiary and for the deconsolidation of a subsidiary. FAS 160 is effective for fiscal years beginning on or after December 15, 2008. Both FAS 141(R) and FAS 160 became effective for us on January 1, 2009. The application of FAS 141(R) and FAS 160 are not expected to have a material impact to us.

In June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* (FSP EITF 03-6-1). FSP EITF 03-6-1 clarifies that share-based payment awards that entitle their holders to receive non-forfeitable dividends before vesting should be considered participating securities and, as such, should be included in the calculation of basic earnings-per-share using the two-class method. Certain of our share-based payment awards entitle the holders to receive non-forfeitable dividends and the application of the provisions of FSP EITF 03-6-1 may have the effect of reducing basic and diluted earnings-per-share by an immaterial amount. FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008, as well as interim periods within those years. Once effective, all prior-period earnings-per-share data presented must be adjusted retrospectively to conform with the provisions of FSP EITF 03-6-1. FSP EITF 03-6-1 will be effective for us beginning in the quarter ending March 31, 2009, and early application is not permitted. The adoption of FSP EITF 03-6-1 is not expected to have a material impact to us.

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

We currently have exposure to interest rate market risk associated with any borrowings that we have under our revolving 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. As of December 31, 2008, we had no borrowings outstanding under our credit facility.

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We conduct a portion of our 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.

The carrying values of cash and cash equivalents, trade receivables and accounts payable approximate fair value due to the short-term maturity of these items.

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, 2008, 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, 2008, 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, 2008.

The effectiveness of our internal control over financial reporting as of December 31, 2008 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page F-2 of this Report and is incorporated by reference into Item 8 of this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting:

There have been no 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***

None.

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PART III

The information required by Part III is omitted from this Report because we expect to file a definitive proxy statement (the 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 and 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.

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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	Second Amended and Restated Bylaws (filed August 6, 2007 as Exhibit 3.3 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 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	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).*
10.4	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).*
10.5	

	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).*
10.6	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).*
10.7	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).*

10.8	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 21, 2005 as Exhibit 10.1 to the Company s Current Report on Form 8-K, and incorporated herein by reference).*
10.9	First Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed June 6, 2008 as Exhibit 10.1 to the Company s Current Report on Form 8-K and incorporated herein by reference).
10.10	Second Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed June 6, 2008 as Exhibit 10.2 to the Company s Current Report on Form 8-K and incorporated herein by reference).
10.11	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).*
10.12	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).*
10.13	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, dated as of September 1, 2007 between Patterson-UTI Energy, Inc. and Cloyce A. Talbott (filed on September 24, 2007 as Exhibit 10.1 to the Company s Current Report on Form 8-K, 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 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).*
10.18	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).*
10.19	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).*
10.20	Form of Indemnification Agreement entered into by Patterson-UTI Energy, Inc. with each of Mark S. Siegel, Cloyce A. Talbott, Douglas J. Wall, Kenneth N. Berns, Curtis W. Huff, Terry H. Hunt, Kenneth R. Peak, Charles O. Buckner, John E. Vollmer III, William L. Moll, Jr. and Gregory W. Pipkin (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).*
10.21	Severance Agreement between Patterson-UTI Energy, Inc. and Douglas J. Wall, effective as of August 31, 2007 (filed September 4, 2007 as Exhibit 10.3 to the Company s Current Report on Form 8-K and incorporated herein by reference).*

10.22 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of August 31, 2007, by and between Patterson-UTI Energy, Inc. and Douglas J. Wall (filed September 4, 2007 as Exhibit 10.2 to the Company s Current Report on Form 8-K and incorporated herein by reference).*

10.23	Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of August 31, 2007, by and between Patterson-UTI Energy, Inc. and William L. Moll, Jr. (filed November 5, 2007 as Exhibit 10.7 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*
10.24	First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and Mark S. Siegel, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.8 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*
10.25	First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and Douglas J. Wall, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.9 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*
10.26	First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and John E. Vollmer, III, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.10 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*
10.27	First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and Kenneth N. Berns, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.11 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*
10.28	First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and William L. Moll, Jr., entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.12 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*
10.29	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).
10.30	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).
10.31	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.:

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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 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. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide 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.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 18, 2009

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PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 81,223	$ 17,434
Accounts receivable, net of allowance for doubtful accounts of $9,330 and $10,014 at December 31, 2008 and 2007, respectively	414,531	373,279
Federal and state income taxes receivable	10,175	
Inventory	41,999	44,416
Deferred tax assets, net	35,928	35,370
Other	57,518	52,286
Total current assets	641,374	522,785
Property and equipment, net	1,937,112	1,841,404
Goodwill	86,234	96,198
Deposits on equipment purchases	43,944	
Other	4,153	4,812
Total assets	$ 2,712,817	$ 2,465,199
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 169,958	$ 156,916
Federal and state income taxes payable		1,458
Accrued expenses	132,655	136,834
Total current liabilities	302,613	295,208
Borrowings under line of credit		50,000
Deferred tax liabilities, net	277,717	219,490
Other	5,545	4,471
Total liabilities	585,875	569,169
Commitments and contingencies (see Note 8)		
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 180,192,093 and 177,385,808 issued and 153,094,803 and 153,942,800 outstanding at December 31, 2008 and 2007, respectively	1,801	1,773

Additional paid-in capital	765,512	703,581
Retained earnings	1,970,824	1,716,620
Accumulated other comprehensive income	5,774	20,207
Treasury stock, at cost, 27,097,290 shares and 23,443,008 shares at December 31, 2008 and 2007, respectively	(616,969)	(546,151)
Total stockholders equity	2,126,942	1,896,030
Total liabilities and stockholders equity	$ 2,712,817	$ 2,465,199

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

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PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2008	2007	2006
	(In thousands, except per share data)		
Operating revenues:			
Contract drilling	$ 1,804,026	$ 1,741,647	$ 2,169,370
Pressure pumping	217,494	202,812	145,671
Drilling and completion fluids	145,246	128,098	192,358
Oil and natural gas	42,360	41,637	39,187
	2,209,126	2,114,194	2,546,586
Operating costs and expenses:			
Contract drilling	1,038,327	963,150	1,002,001
Pressure pumping	132,570	105,273	77,755
Drilling and completion fluids	126,900	108,752	150,372
Oil and natural gas	12,793	10,864	13,374
Goodwill impairment	9,964		
Depreciation, depletion and other impairment	268,431	249,206	196,370
Selling, general and administrative	68,190	64,623	55,065
Embezzlement costs (recoveries)		(43,955)	3,081
Net loss (gain) on asset disposals/retirements	6,071	(16,545)	3,819
Other operating expenses	4,350	2,550	5,585
	1,667,596	1,443,918	1,507,422
Operating income	541,530	670,276	1,039,164
Other income (expense):			
Interest income	1,555	2,355	5,925
Interest expense	(639)	(2,187)	(1,602)
Other	502	363	347
	1,418	531	4,670
Income before income taxes and cumulative effect of change in accounting principle	542,948	670,807	1,043,834
Income tax expense (benefit):			
Current	129,840	193,897	375,373
Deferred	66,039	38,271	(4,106)
	195,879	232,168	371,267

Income before cumulative effect of change in accounting principle		347,069		438,639		672,567
Cumulative effect of change in accounting principle, net of related income tax expense of $398						687
Net income	$	347,069	$	438,639	$	673,254
Income before cumulative effect of change in accounting principle per common share:						
Basic	$	2.26	$	2.83	$	4.07
Diluted	$	2.24	$	2.79	$	4.02
Net income per common share:						
Basic	$	2.26	$	2.83	$	4.08
Diluted	$	2.24	$	2.79	$	4.02
Weighted average number of common shares outstanding:						
Basic		153,379		154,755		165,159
Diluted		154,717		156,997		167,413
Cash dividends per common share	$	0.60	$	0.44	$	0.28

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

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PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY

	Common Stock Number of Shares	Common Stock Amount	Additional Paid-in Capital	Deferred Compensation	Retained Earnings	Accumulated Other Comprehensive Income	Treasury Stock	Total
				(In thousands)				
lance, December 31, 05	175,909	$ 1,759	$ 672,151	$ (9,287)	$ 719,113	$ 8,565	$ (25,290)	$ 1,367,01
mprehensive income:								
t income					673,254			673,25
reign currency nslation adjustment, (net tax of $6)						(175)		(17
tal comprehensive ome					673,254	(175)		673,07
mination of deferred mpensation due to ange in accounting nciple			(9,287)	9,287				
uance of restricted stock	613	6	(6)					
rfeitures of restricted ares	(47)	(1)	1					
ercise of stock options	181	2	1,944					1,94
x benefit related to ck-based compensation			1,087					1,08
ock-based compensation, t of cumulative effect of ange in accounting nciple			15,179					15,17
yment of cash dividend					(45,825)			(45,82
rchase of treasury stock							(450,011)	(450,01
lance, December 31, 06	176,656	1,766	681,069		1,346,542	8,390	(475,301)	1,562,46
mprehensive income:								
t income					438,639			438,63
reign currency nslation adjustment, (net tax of $6,755)						11,817		11,81
					438,639	11,817		450,45

tal comprehensive ome								
uance of restricted stock	601	6	(6)					
rfeitures of restricted ares	(101)	(1)	1					
ercise of stock options	230	2	2,048					2,05
x benefit related to ck-based compensation			1,105					1,10
ock-based compensation			19,364					19,36
yment of cash dividend					(68,561)			(68,56
rchase of treasury stock							(70,850)	(70,85
lance, December 31, 07	177,386	1,773	703,581		1,716,620	20,207	(546,151)	1,896,03
mprehensive income:								
t income					347,069			347,06
reign currency nslation adjustment, (net tax of $8,368)						(14,433)		(14,43
tal comprehensive ome					347,069	(14,433)		332,63
uance of restricted stock	577	6	(6)					
rfeitures of restricted ares	(75)	(1)	1					
ercise of stock options	2,304	23	25,525					25,54
x benefit related to ck-based compensation			16,280					16,28
ock-based compensation			20,131					20,13
yment of cash dividend					(92,865)			(92,86
rchase of treasury stock							(70,818)	(70,81
lance, December 31, 08	180,192	$ 1,801	$ 765,512	$	$ 1,970,824	$ 5,774	$ (616,969)	$ 2,126,94

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

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PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2008	2007	2006
	(In thousands)		
Cash flows from operating activities:			
Net income	$ 347,069	$ 438,639	$ 673,254
Adjustments to reconcile net income to net cash provided by operating activities:			
Goodwill impairment	9,964		
Depreciation, depletion and other impairment	268,431	249,206	196,370
Provision for bad debts	4,350	2,550	5,400
Dry holes and abandonments	1,617	1,309	4,338
Deferred income tax expense (benefit)	66,039	38,271	(3,708)
Stock-based compensation expense	20,131	19,364	15,179
Net loss (gain) on asset disposals/retirements	6,071	(16,545)	3,819
Changes in operating assets and liabilities:			
Accounts receivable	(50,567)	112,353	(67,417)
Income taxes receivable/payable	(11,258)	7,174	(16,231)
Inventory and other current assets	5,492	4,853	(47,406)
Accounts payable	10,341	(40,317)	27,184
Accrued expenses	(3,750)	(6,104)	32,972
Other liabilities	1,074	1,471	13,416
Net cash provided by operating activities	675,004	812,224	837,170
Cash flows from investing activities:			
Acquisitions		(29,000)	
Purchases of property and equipment	(448,893)	(607,686)	(597,919)
Proceeds from disposal of assets	11,617	34,224	10,934
Net cash used in investing activities	(437,276)	(602,462)	(586,985)
Cash flows from financing activities:			
Purchases of treasury stock	(70,818)	(70,850)	(450,011)
Dividends paid	(92,865)	(68,561)	(45,825)
Tax benefit related to stock-based compensation	16,280	1,105	1,087
Proceeds from borrowings under line of credit		142,500	274,000
Repayment of borrowings under line of credit	(50,000)	(212,500)	(154,000)
Line of credit issuance costs			(342)
Proceeds from exercise of stock options	25,548	2,050	1,946
Net cash used in financing activities	(171,855)	(206,256)	(373,145)
Effect of foreign exchange rate changes on cash	(2,084)	543	(53)

Net increase (decrease) in cash and cash equivalents	63,789	4,049	(123,013)
Cash and cash equivalents at beginning of year	17,434	13,385	136,398
Cash and cash equivalents at end of year	$ 81,223	$ 17,434	$ 13,385
Supplemental disclosure of cash flow information:			
Net cash paid during the year for:			
Interest expense	$ (323)	$ (1,808)	$ (1,278)
Income taxes	(126,331)	(176,281)	(377,847)

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

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PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

NOTES TO 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, Alabama, Colorado, Arizona, Utah, Wyoming, Montana, North Dakota, South Dakota, Pennsylvania, West Virginia 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, New Mexico, Oklahoma and Louisiana. The Company owns and invests in oil and natural gas assets as a working interest owner. The oil and natural gas properties in which the Company holds interests are located primarily in Texas, New Mexico, Mississippi and Louisiana.

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. Except for wholly-owned subsidiaries, the Company has no controlling financial interests in any entity 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 its functional currency. The effects of exchange rate changes are reflected in accumulated other comprehensive income, which is a separate component of stockholders equity.

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. The Company follows 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, 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. The Company did not have any footage or turnkey contracts during the years ended December 31, 2008, 2007 or 2006.

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 at least quarterly. 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.

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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 shown below:

	Useful Lives
Drilling rigs and other equipment	2-15
Buildings	15-20
Other	3-12

Long-lived assets, including property and equipment, are evaluated for impairment when certain triggering events or changes in circumstances indicate that the carrying values may not be recoverable over their estimated remaining useful life.

Oil and natural gas properties Working interests in 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 a triggering 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 based on management s expectation of future pricing over the lives of the respective fields. These estimates are then 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 assess potential 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 triggering events or circumstances indicate that the fair value of the asset has decreased below its carrying value in accordance with the provisions of Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets* (FAS 142). As discussed in Note 4, the Company determined that goodwill in its drilling and completion fluids reporting unit was impaired in connection with its annual impairment testing performed as of December 31, 2008.

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.

Disposals/retirements Upon disposition or retirement of property and equipment, the cost and related accumulated depreciation are removed and any resulting gain or loss is reflected in the consolidated statement of income.

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Net income per common share The Company provides a dual presentation of its net income per common share in its Consolidated Statements of Income: 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 common shares outstanding during the period excluding non-vested restricted stock. Diluted EPS is based on the weighted-average number of common shares outstanding plus the impact of dilutive instruments, including stock options, restricted stock and restricted stock units using the treasury stock method. The following table presents information necessary to calculate net income per share for the years ended December 31, 2008, 2007 and 2006 as well as 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):

	2008	2007	2006
Net income	$ 347,069	$ 438,639	$ 673,254
Weighted average number of common shares outstanding, excluding non-vested restricted stock	153,379	154,755	165,159
Basic net income per common share	$ 2.26	$ 2.83	$ 4.08
Weighted average number of common shares outstanding, excluding non-vested restricted stock	153,379	154,755	165,159
Dilutive effect of stock options and restricted shares	1,338	2,242	2,254
Weighted average number of diluted common shares outstanding	154,717	156,997	167,413
Diluted net income per common share	$ 2.24	$ 2.79	$ 4.02
Potentially dilutive securities excluded as anti-dilutive	2,455	2,460	800

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.

The Company adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109* (FIN 48) on January 1, 2007. 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. As a result of the adoption of FIN 48 in 2007, the Company reduced a reserve for an uncertain tax position related to a prior business combination that had originally been recorded as goodwill (see Note 4). The impact of adjustments to reserves with respect to other uncertain tax positions was not material. In connection with the adoption of FIN 48, the Company established a policy to account for interest and penalties with respect to income taxes as operating expenses.

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), *Share-Based Payment* (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. (See Note 10)

Statement of cash flows For purposes of reporting cash flows, cash and cash equivalents include cash on deposit and money market funds.

Recently Issued Accounting Standards 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. The initial application of FAS 157 is limited to financial assets and liabilities and became effective on January 1, 2008 for the Company. The impact of the initial application of FAS 157 was not material. On January 1, 2009, the Company adopted FAS 157 on a prospective basis for non-financial assets and liabilities that are not measured at fair value on a recurring basis. The application of FAS 157 to the Company s non-financial assets and liabilities will primarily be limited to assets acquired and liabilities assumed in a business combination, asset retirement obligations and asset impairments, including goodwill and long-lived assets. This application of FAS 157 is not expected to have a material impact to the Company.

In December 2007, the FASB issued Statement No. 141(R), *Business Combinations* (FAS 141(R)) and Statement No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51* (FAS 160). FAS 141(R) is a revision of Statement No. 141, *Business Combinations*, and calls for significant changes from current practice in accounting for business combinations. FAS 141(R) is effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. FAS 160 amends ARB 51 to establish accounting and reporting standards for the non-controlling interest in a subsidiary and for the deconsolidation of a subsidiary. FAS 160 is effective for fiscal years beginning on or after December 15, 2008. Both FAS 141(R) and FAS 160 became effective for the Company on January 1, 2009. The application of FAS 141(R) and FAS 160 are not expected to have a material impact to the Company.

In June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* (FSP EITF 03-6-1). FSP EITF 03-6-1 clarifies that share-based payment awards that entitle their holders to receive non-forfeitable dividends before vesting should be considered participating securities and, as such, should be included in the calculation of basic earnings-per-share using the two-class method. Certain of the Company s share-based payment awards entitle the holders to receive non-forfeitable dividends and the application of the provisions of FSP EITF 03-6-1 may have the effect of reducing basic and diluted earnings-per-share by an immaterial amount. FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008, as well as interim periods within those years. Once effective, all prior-period earnings-per-share data presented must be adjusted retrospectively to conform with the provisions of FSP EITF 03-6-1. FSP EITF 03-6-1 will be effective for the Company beginning in the quarter ending March 31, 2009 and early application is not permitted. The adoption of FSP EITF 03-6-1 is not expected to have a material impact to the Company.

Reclassifications Certain reclassifications have been made to the 2007 and 2006 consolidated financial statements in order for them to conform with the 2008 presentation.

2. Acquisitions

On October 9, 2007, the Company acquired three recently refurbished SCR electric land-based drilling rigs and spare drilling equipment for $29.0 million. 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.

3. Property and Equipment

Property and equipment consisted of the following at December 31, 2008 and 2007 (in thousands):

	2008	2007
Equipment	$ 2,897,431	$ 2,748,007
Oil and natural gas properties	89,809	75,732
Buildings	61,529	50,955
Land	10,196	9,991
	3,058,965	2,884,685
Less accumulated depreciation and depletion	(1,121,853)	(1,043,281)
Property and equipment, net	$ 1,937,112	$ 1,841,404

Depreciation, depletion and other impairment The following table summarizes depreciation, depletion and impairment expense for 2008, 2007 and 2006 (in millions):

	2008	2007	2006
Depreciation and impairment expense	$ 256.9	$ 235.8	$ 187.3
Depletion expense	11.5	13.4	9.1
Total	$ 268.4	$ 249.2	$ 196.4

As required under Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (FAS 144), the Company evaluates the recoverability of its long-lived assets whenever events or changes in circumstances indicate that their carrying amounts may not be recoverable. In light of the adverse market conditions affecting the Company beginning in the fourth quarter of 2008 and continuing into 2009, including a substantial decrease in the operating levels of certain of its business segments, a significant decline in oil and natural gas commodity prices, and the preliminary results of the Company s annual goodwill impairment test (see Note 4), management deemed it necessary to assess the recoverability of long-lived assets within its contract drilling, drilling and completion fluids, and oil and natural gas business segments. Management concluded that the Company s pressure pumping segment was not subject to the same events and trends noted above to the same degree, and thus did not require further assessment of recoverability under FAS 144.

Management performed the first step of its impairment assessment under the provisions of FAS 144 using the undiscounted cash flows for each long-lived asset or asset group, using assumptions and methods consistent with those used in its assessment of the carrying values of goodwill for its contract drilling and drilling and completion fluids reporting units. Based on the results of these impairment tests, the carrying amounts of long-lived assets in the contract drilling, drilling and completion fluids and oil and natural gas segments were determined to be recoverable, except as described below.

Management s analysis indicated that the carrying amounts of certain oil and natural gas properties were not recoverable. The Company recorded a $2.4 million impairment charge in the fourth quarter of 2008 related to these properties, based on the related estimated discounted cash flows. This impairment charge reflects management s revised estimate of expected future net cash flows from such properties due, in large part, to the significant decline in commodity prices in the fourth quarter of 2008.

Also, during the fourth quarter of 2008, the Company evaluated its fleet of marketable drilling rigs and identified 22 rigs that it determined would no longer be marketed as rigs. The components which made up these rigs were evaluated, and those components with continuing utility to the Company s other marketed rigs (with a net book value of $13.4 million) were transferred to yards to be used as spare equipment. The remaining components of these rigs were retired and the associated net book value of $10.4 million was expensed in the Company s statement of operations as a component of net loss (gain) on asset disposals/retirements .

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4. Goodwill

Goodwill by operating segment as of December 31, 2008 and 2007 and changes for the years then ended are as follows (in thousands):

	2008	2007
Contract Drilling:		
Goodwill at beginning of year	$ 86,234	$ 89,092
Changes to goodwill		(2,858)
Goodwill at end of period	86,234	86,234
Drilling and completion fluids:		
Goodwill at beginning of year	9,964	9,964
Changes to goodwill	(9,964)	
Goodwill at end of period		9,964
Total goodwill	$ 86,234	$ 96,198

In connection with the implementation of FIN 48 as of January 1, 2007 as discussed in Note 1 of these Consolidated Financial Statements, the Company determined that a tax reserve of $2.9 million related to a prior business combination should be reduced to zero. This reserve had originally been established in connection with the allocation of the purchase price in the transaction and was reflected as a component of goodwill recorded in the transaction.

Goodwill is evaluated at least annually to determine if the fair value of recorded goodwill has decreased below its carrying value. 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.

In connection with its annual goodwill impairment assessment performed as of December 31, 2008, the Company performed an impairment test of its contract drilling and drilling and completion fluids reporting units under the provisions of FAS 142. In light of the adverse market conditions affecting the Company s common stock price beginning in the fourth quarter of 2008 and continuing into 2009, including a significant decrease in the number of its rigs operating and a significant decline in oil and natural gas commodity prices, management utilized a discounted cash flow methodology to estimate the fair values of the Company s reporting units. In completing its first step of the analysis, management used a three-year projection of discounted cash flows, plus a terminal value determined using the constant growth method to estimate the fair value of its reporting units. In developing these fair value estimates, certain key assumptions included an assumed discount rate of 13.99% for all reporting units, an assumed long-term growth rate of 3.50% for the contract drilling reporting unit and an assumed long-term growth rate of 2.00% for the drilling and completion fluids reporting unit.

Based on the results of the first step of the impairment test, management concluded that no impairment was indicated in its contract drilling reporting unit; however, an impairment was indicated in its drilling and completion fluids reporting unit. In validating this conclusion, management considered the results of its long-lived asset impairment tests and performed sensitivity analyses of the key assumptions used in deriving the respective fair values of its reporting units. Management performed the second step of the analysis of its drilling and completion fluids reporting unit, allocating the estimated fair value to the identifiable tangible and intangible assets and liabilities of this reporting unit based on their respective values. This allocation indicated no residual value for goodwill, and accordingly the Company recorded an impairment charge of $9.964 million in its December 31, 2008 statement of operations.

In the event that market conditions continue to deteriorate, the Company may be required to record an impairment of goodwill in its contract drilling reporting unit in the future, and such impairment could be material.

5. Accrued Expenses

Accrued expenses consisted of the following at December 31, 2008 and 2007 (in thousands):

	2008	2007
Salaries, wages, payroll taxes and benefits	$ 30,334	$ 33,816
Workers compensation liability	70,439	70,989
Sales, use and other taxes	12,015	12,119
Insurance, other than workers compensation	14,209	16,308
Other	5,658	3,602
	$ 132,655	$ 136,834

6. 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. This liability is included in the caption other liabilities on the consolidated balance sheet. The following table describes the changes to the Company s asset retirement obligations during 2008 and 2007 (in thousands):

	2008	2007
Balance at beginning of year	$ 1,593	$ 1,829
Liabilities incurred	516	276
Liabilities settled	(424)	(862)
Accretion expense	59	61
Revision in estimated costs of plugging oil and natural gas wells	1,303	289
Asset retirement obligation at end of year	$ 3,047	$ 1,593

7. Borrowings Under Line of Credit

The Company has an unsecured revolving line of credit (LOC) with a maximum borrowing capacity of $375 million which expires on December 16, 2009. Interest is paid on outstanding LOC balances at a floating rate ranging from LIBOR plus 0.625% to 1.0% or the prime rate at the Company s election. This arrangement includes various fees, including a commitment fee on the average daily unused amount (0.15% at December 31, 2008). 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 impact its ability to operate or react to opportunities that might arise. There can be no assurance that the Company will be able to renew or replace the existing revolving line of credit with similar terms, if at all. As of December 31, 2008, the Company had no borrowings outstanding under the LOC. The Company had $58.5 million in letters of credit outstanding at December 31, 2008, however, and as a result the Company had available borrowing capacity of approximately $316.5 million at such date.

8. Commitments, Contingencies and Other Matters

Commitments As of December 31, 2008, the Company maintained letters of credit in the aggregate amount of $58.5 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 the calendar year and are typically renewed annually. As of December 31, 2008, no amounts had been drawn under the letters of credit.

As of December 31, 2008, the Company had commitments to purchase approximately $269 million of major equipment.

Contingencies The Company s contract services 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 $10.0 million of aggregate coverage and excess liability and umbrella coverages up to $200 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. Accrued expenses related to insurance claims are set forth in Note 5.

The Company believes it is adequately insured for bodily injury 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. There can be no assurance that such insurance coverage will always be available on terms that are satisfactory to the Company.

The Company is party to various 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, results of operations or cash flows.

Other Matters The Company has Change in Control Agreements with its Chairman of the Board, Chief Executive Officer, two Senior Vice Presidents and its General Counsel (the Key Employees). Each Change in Control Agreement generally has an initial 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 generally be entitled to, among other things,

a 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), 2 times (in the case of the Senior Vice Presidents) or 1.5 times (in the case of the General Counsel) 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 and General Counsel).

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.

9. Stockholders Equity

Cash Dividends The Company paid cash dividends during the years ended December 31, 2006, 2007 and 2008 as follows:

	Per Share	Total (In thousands)
2006:		
Paid on March 30, 2006	$ 0.04	$ 6,906
Paid on June 30, 2006	0.08	13,413
Paid on September 29, 2006	0.08	13,024
Paid on December 29, 2006	0.08	12,482
Total cash dividends	$ 0.28	$ 45,825
2007:		
Paid on March 30, 2007	$ 0.08	$ 12,527
Paid on June 29, 2007	0.12	18,860
Paid on September 28, 2007	0.12	18,690
Paid on December 28, 2007	0.12	18,484
Total cash dividends	$ 0.44	$ 68,561
2008:		
Paid on March 28, 2008	$ 0.12	$ 18,493
Paid on June 27, 2008	0.16	25,011
Paid on September 29, 2008	0.16	24,803
Paid on December 29, 2008	0.16	24,558
Total cash dividends	$ 0.60	$ 92,865

On February 11, 2009, the Company s Board of Directors approved a cash dividend on its common stock in the amount of $0.05 per share to be paid on March 31, 2009 to holders of record as of March 12, 2009. The amount and timing of all future dividend payments, if any, 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 2004, the Company s Board of Directors authorized a stock buyback program (2004 Program) for the purchase of the Company s outstanding common stock in open market or privately negotiated transactions. During 2006, the Company completed the purchase of 16,645,342 shares of its common stock under the 2004 Program in the open market at a cost of approximately $450 million.

On August 1, 2007, the Company s Board of Directors approved a new stock buyback program (2007 Program), authorizing purchases of up to $250 million of the Company s common stock in open market or privately negotiated transactions. During the year ended December 31, 2007, the Company purchased 3,308,850 shares of its common stock under the 2007 Program at a cost of approximately $70.4 million. During the year ended December 31, 2008, the Company purchased 3,502,047 shares of its common stock under the 2007 Program at a cost of approximately $66.3 million. As of December 31, 2008, the Company is authorized to purchase approximately $113 million of the Company s outstanding common stock under the 2007 Program. Shares purchased under the stock buyback programs have been accounted for as treasury stock.

Additionally, the Company purchased 152,235 and 20,269 shares of treasury stock from employees during 2008 and 2007, respectively. These shares were purchased at fair market value upon the vesting of restricted stock to provide the employees with the funds necessary to satisfy payroll tax withholding obligations. The total purchase price for these shares was approximately $4.5 million and $496,000 in 2008 and 2007, respectively. These purchases were made pursuant to the terms of the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan and not pursuant to the stock buyback programs.

10. Stock-based Compensation

Effective January 1, 2006, the Company adopted the provisions of Financial Accounting Standards Board Statement No. 123(R), *Share-Based Payment* (SFAS 123(R)). The Company 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 share-based awards have been equity instruments in the form of stock options, restricted stock awards or restricted stock units and have included service and, in certain cases, performance conditions. The Company issues shares of common stock when vested stock option awards are exercised, when restricted stock awards are granted and when restricted stock units vest. For the year ended December 31, 2008, the Company recognized $20.1 million in stock-based compensation expense and a related income tax benefit of approximately $7.1 million. For the year ended December 31, 2007, the Company recognized $19.4 million in stock-based compensation expense and a related income tax benefit of approximately $6.7 million. 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. In addition, effective January 1, 2006, the Company 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.

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. During 2008, the Company amended the 2005 Plan to, among other things, increase the total number of shares authorized for grant from 6,250,000 to 10,250,000. The Company s share-based compensation plans at December 31, 2008 follow:

Plan Name	Shares Authorized for Grant	Awards Outstanding	Shares Available for Grant
Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan, as amended (2005 Plan)	10,250,000	4,081,571	4,637,004
Patterson-UTI Energy, Inc. Amended and Restated 1997 Long-Term Incentive Plan, as amended (1997 Plan)		2,950,634	
Amended and Restated Patterson-UTI Energy, Inc. 2001 Long-Term Incentive Plan (2001 Plan)		248,938	
Amended and Restated Non-Employee Director Stock Option Plan of Patterson-UTI Energy, Inc. (Non-Employee Director Plan)		40,000	
Amended and Restated Patterson-UTI Energy, Inc. 1996 Employee Stock Option Plan (1996 Plan)		51,400	
Patterson-UTI Energy, Inc., 1993 Incentive Stock Plan, as amended (1993 Plan)		8,100	

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.

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The 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. As of December 31, 2008, only non-incentive stock options, restricted stock awards and restricted stock units 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 vested 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 and have a term of five 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.

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 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 estimates the grant date fair values of stock options using the Black-Scholes-Merton valuation model (Black-Scholes). 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 are 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 are 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, 2008, 2007 and 2006 follow:

	2008	**2007**	**2006**
Volatility	37.04%	36.37%	33.18%
Expected term (in years)	4.17	4.00	4.00
Dividend yield	2.27%	1.97%	1.09%
Risk-free interest rate	2.91%	4.55%	4.87%

Stock option activity for the year ended December 31, 2008 follows:

	Shares	**Weighted-Average Exercise Price**

Outstanding at beginning of year	7,403,084	$	17.52
Granted	834,500	$	25.99
Exercised	(2,303,877)	$	11.09
Expired	(135)	$	14.64
Outstanding at end of year	5,933,572	$	21.20
Exercisable at end of year	4,483,793	$	19.77

Options outstanding at December 31, 2008 have an aggregate intrinsic value of approximately $1.1 million and a weighted-average remaining contractual term of 6.3 years. Options exercisable at December 31, 2008 have an aggregate intrinsic value of approximately $1.1 million and a weighted-average remaining contractual term of

5.5 years. Additional information with respect to options granted, vested and exercised during the years ended December 31, 2008, 2007 and 2006 follows:

	2008	2007	2006
Weighted-average grant-date fair value of stock options granted (per share)	$ 7.20	$ 7.09	$ 8.62
Grant-date fair value of stock options vested during the year (in thousands)	$ 6,761	$ 5,613	$ 6,900
Aggregate intrinsic value of stock options exercised (in thousands)	$ 45,240	$ 3,186	$ 3,377

As of December 31, 2008, options to purchase 1,449,779 shares were outstanding and not vested. All of these non-vested options are expected to ultimately vest. Additional information as of December 31, 2008 with respect to these options that are expected to vest follows:

Aggregate intrinsic value	$ 0
Weighted-average remaining contractual term	8.85 years
Weighted-average remaining expected term	2.95 years
Weighted-average remaining vesting period	1.89 years
Unrecognized compensation cost	$ 8.9 million

Restricted Stock For all restricted stock awards to date, shares of common stock were issued when granted. Non-vested shares are subject to forfeiture for failure to fulfill service conditions and, in certain cases, performance conditions. Non-forfeitable dividends are paid on non-vested 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 non-vested 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.

For restricted stock awards granted prior to 2008, the Company used the graded-vesting attribution method to recognize periodic compensation cost over the vesting period. For restricted stock awards granted in 2008, the Company uses the straight-line method to recognize periodic compensation cost over the vesting period.

Restricted stock activity for the year ended December 31, 2008 follows:

	Shares	Weighted-Average Grant Date Fair Value
Non-vested restricted stock outstanding at beginning of year	1,490,150	$ 26.22

Granted	576,950	$	30.31
Vested	(562,987)	$	24.37
Forfeited	(74,542)	$	28.27
Non-vested restricted stock outstanding at end of year	1,429,571	$	28.49

As of December 31, 2008, approximately 1,368,000 shares of non-vested restricted stock outstanding are expected to vest. Additional information as of December 31, 2008 with respect to these shares that are expected to vest follows:

Aggregate intrinsic value	$ 15.7 million
Weighted-average remaining vesting period	1.66 years
Unrecognized compensation cost	$ 18.3 million

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Restricted Stock Units For all restricted stock units awarded to date, shares of common stock are not issued until the awards vest. Awards are subject to forfeiture for failure to fulfill service conditions. Non-forfeitable cash dividend equivalents are paid on non-vested restricted stock units.

Restricted stock unit activity from January 1, 2008 to December 31, 2008 follows:

	Shares	Weighted Average Grant Date Fair Value
Non-vested restricted stock units outstanding at January 1, 2008		$
Granted	17,500	$ 31.60
Vested		$
Forfeited		$
Non-vested restricted stock units outstanding at December 31, 2008	17,500	$ 31.60

Dividends on Equity Awards Non-forfeitable cash dividends and dividend equivalents paid on equity awards are recognized as follows:

Dividends are recognized as reductions of retained earnings for the portion of restricted stock awards expected to vest.

Dividends are recognized as additional compensation cost for the portion of restricted stock awards that are not expected to vest or that ultimately do not vest.

Dividend equivalents are recognized as additional compensation cost for restricted stock units.

Forfeiture assumptions in regard to these cash dividend payments are the same as forfeiture assumptions used to recognize compensation cost.

11. Leases

The Company incurred rent expense of $37.6 million, $33.9 million and $31.8 million for the years 2008, 2007 and 2006, respectively. Rent expense is primarily related to short-term equipment rentals that are passed through to customers. The Company s obligations under non-cancelable operating lease agreements are not material to the Company s operations or cash flows.

12. Income Taxes

The Company adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109* (FIN 48), on January 1, 2007. 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. As a result of the adoption of FIN 48, the Company reduced a reserve that had been established for an uncertain tax position related to a prior business combination. The reserve was originally recorded as goodwill (see Note 4). The impact of adjustments to reserves related to other uncertain tax positions was not material. As of December 31, 2008, the Company had no unrecognized tax benefits. In connection with the adoption of FIN 48, the Company established a policy to account for interest and penalties related to uncertain income tax positions as operating expenses. As of December 31, 2008, the tax years ended December 31, 2005 through December 31, 2007 are open for examination by U.S. taxing authorities. As of December 31, 2008, the tax years ended December 31, 2004 through December 31, 2007 are open for examination by Canadian taxing authorities.

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Components of the income tax provision applicable to Federal, state and foreign income taxes for the years ended December 31, 2008, 2007 and 2006 are as follows (in thousands):

	2008	2007	2006
Federal income tax expense (benefit):			
Current	$ 118,887	$ 172,221	$ 344,395
Deferred	58,480	36,864	(5,851)
	177,367	209,085	338,544
State income tax expense:			
Current	6,697	16,456	21,371
Deferred	7,116	983	1,392
	13,813	17,439	22,763
Foreign income tax expense:			
Current	4,256	5,220	9,607
Deferred	443	424	353
	4,699	5,644	9,960
Total income tax expense (benefit):			
Current	129,840	193,897	375,373
Deferred	66,039	38,271	(4,106)
Total income tax expense	$ 195,879	$ 232,168	$ 371,267

The difference between the statutory Federal income tax rate and the effective income tax rate for the years ended December 31, 2008, 2007 and 2006 is summarized as follows:

	2008	2007	2006
Statutory tax rate	35.0%	35.0%	35.0%
State income taxes	1.7	1.4	1.4
Permanent differences	(0.4)	(1.6)	(0.8)
Other, net	(0.2)	(0.2)	0.0
Effective tax rate	36.1%	34.6%	35.6%

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

	December 31, 2008	Net Change	December 31, 2007	Net Change	December 31, 2006	Net Change	December 31, 2005
Deferred tax assets:							
Current:							
Federal net operating loss carryforwards	$	$ (374)	$ 374	$ (1,496)	$ 1,870	$	$ 1,870
Workers compensation allowance	25,984	(602)	26,586	223	26,363	6,902	19,461
Embezzlement costs	728	68	660	(13,634)	14,294	14,294	
Other	21,623	3,219	18,404	3,903	14,501	3,137	11,364
	48,335	2,311	46,024	(11,004)	57,028	24,333	32,695
Non-current:							
Federal net operating loss carryforwards				(374)	374	(1,871)	2,245
AMT credit		(118)	118		118		118
Federal benefit of foreign deferred tax liabilities	9,416	443	8,973	424	8,549	353	8,196
Federal benefit of state deferred tax liabilities	7,070	1,643	5,427	735	4,692	460	4,232
Other	11,994	1,995	9,999	2,890	7,109	6,172	937
	28,480	3,963	24,517	3,675	20,842	5,114	15,728
Total deferred tax assets	76,815	6,274	70,541	(7,329)	77,870	29,447	48,423
Deferred tax liabilities:							
Current:							
Other	(12,407)	(1,753)	(10,654)	(2,492)	(8,161)	(1,848)	(6,313)
Non-current:							
Property and equipment basis difference	(302,327)	(70,362)	(231,965)	(28,466)	(203,500)	(23,775)	(179,725)
Other	(3,870)	8,172	(12,042)	(6,741)	(5,301)	(110)	(5,191)
	(306,197)	(62,190)	(244,007)	(35,207)	(208,801)	(23,885)	(184,916)

Total deferred tax liabilities	(318,604)	(63,943)	(254,661)	(37,699)	(216,962)	(25,733)	(191,229)
Net deferred tax liability	$ (241,789)	$ (57,669)	$ (184,120)	$ (45,028)	$ (139,092)	$ 3,714	$ (142,806)

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, 2008 and 2007 to be realized as a result of the reversal of existing taxable temporary differences giving rise to deferred tax liabilities and the generation of taxable income; therefore, no valuation allowance is necessary.

Other deferred tax assets consist primarily of various allowance accounts and tax-deferred expenses expected to generate future tax benefit of approximately $34 million. Other deferred tax liabilities consist primarily of receivables from insurance companies and tax-deferred income not yet recognized for tax purposes.

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13. Employee Benefits

The Company maintains a 401(k) plan for all eligible employees. The Company s operating results include expenses of approximately $4.8 million in 2008, $4.2 million in 2007 and $3.1 million in 2006 for the Company s cash contributions to the plan.

14. Business Segments

The Company s revenues, operating profits and identifiable assets are primarily attributable to four business segments: (i) contract drilling of oil and natural gas wells, (ii) pressure pumping services, (iii) drilling and completion fluids services and (iv) the investment, on a working interest basis, in oil and natural gas properties. 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 operating decision maker and their results are regularly reviewed by the chief operation decision maker for purposes of making decisions about resource allocation and assessing their performance.

Contract Drilling The Company markets its contract drilling services to major and independent oil and natural gas operators. As of December 31, 2008, the Company had 344 marketable land-based drilling rigs, of which 93 of the drilling rigs were based in west Texas and southeastern New Mexico; 92 in north central and eastern Texas, northern Louisiana, Mississippi and Alabama; 56 in the Rocky Mountain region (Colorado, Arizona, Utah, Wyoming, Montana, North Dakota and South Dakota); 50 in south Texas; 27 in the Texas panhandle, Oklahoma and Arkansas; 20 in western Canada; and 6 in the Appalachian Basin.

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, 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 has been engaged in the development, exploration, acquisition and production of oil and natural gas. Through October 31, 2007, the Company served as operator with respect to several properties and was actively involved in the development, exploration, acquisition and production of oil and natural gas. Effective November 1, 2007 the Company sold the related operations portion of its exploration and production business. The Company continues to own and invest in oil and natural gas assets as a working interest owner. The Company s oil and natural gas interests are located primarily in Texas, New Mexico, Mississippi and Louisiana.

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

	Years Ended December 31,		
	2008	2007	2006
Revenues:			
Contract drilling(a)	$ 1,808,600	$ 1,744,884	$ 2,174,805
Pressure pumping	217,494	202,812	145,671
Drilling and completion fluids(b)	145,423	128,447	192,974
Oil and natural gas	42,360	41,637	39,187
Total segment revenues	2,213,877	2,117,780	2,552,637
Elimination of intercompany revenues(a)(b)	(4,751)	(3,586)	(6,051)
Total revenues	$ 2,209,126	$ 2,114,194	$ 2,546,586
Income (loss) before income taxes:			
Contract drilling	$ 531,025	$ 558,792	$ 991,449
Pressure pumping	42,019	64,257	44,835
Drilling and completion fluids	(4,558)	6,528	28,759
Oil and natural gas	13,711	10,998	8,660
	582,197	640,575	1,073,703
Corporate and other	(34,596)	(30,799)	(27,639)
Embezzlement (costs) recoveries(c)		43,955	(3,081)
Net (loss) gain on asset disposals/retirements(d)	(6,071)	16,545	(3,819)
Interest income	1,555	2,355	5,925
Interest expense	(639)	(2,187)	(1,602)
Other	502	363	347
Income before income taxes	$ 542,948	$ 670,807	$ 1,043,834
Identifiable assets:			
Contract drilling	$ 2,255,421	$ 2,132,910	$ 1,849,923
Pressure pumping	210,805	154,120	111,787
Drilling and completion fluids	99,433	91,989	106,032
Oil and natural gas	31,760	37,885	65,443
Corporate and other(e)	115,398	48,295	59,318
Total assets	$ 2,712,817	$ 2,465,199	$ 2,192,503
Depreciation, depletion and impairment:			
Contract drilling	$ 229,311	$ 213,812	$ 168,607
Pressure pumping	19,600	14,311	9,896
Drilling and completion fluids	2,830	2,860	2,706
Oil and natural gas	15,856	17,410	14,368
Corporate and other	834	813	793

Total depreciation, depletion and impairment	$	268,431	$	249,206	$	196,370
Capital expenditures:						
Contract drilling	$	360,645	$	539,506	$	531,087
Pressure pumping		61,289		47,582		41,262
Drilling and completion fluids		3,467		3,082		4,222
Oil and natural gas		22,981		17,516		21,198
Corporate and other		511				150
Total capital expenditures	$	448,893	$	607,686	$	597,919

(a) Includes contract drilling intercompany revenues of approximately $4.6 million, $3.2 million and $5.4 million for the years ended December 31, 2008, 2007 and 2006, respectively.

(b) Includes drilling and completion fluids intercompany revenues of approximately $177,000, $348,000 and $616,000 for the years ended December 31, 2008, 2007 and 2006, respectively.

(c) 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 from the Company prior to his termination in 2005. Embezzlement costs in 2006 include professional fees and other costs incurred as a result of the embezzlement. The net embezzlement recovery in 2007 includes the recognition of the recovery of assets seized by a court appointed receiver, net of related professional fees.

(d) Gains or losses associated with the disposal or retirement of assets relate to decisions of the executive management group regarding corporate strategy. Accordingly, the related gains or losses have been separately presented and excluded from the results of specific segments.

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

15. 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 it has placed its demand deposits and temporary cash investments with high credit-quality financial institutions. At December 31, 2008 and 2007, the Company s demand deposits and temporary cash investments consisted of the following (in thousands):

	2008	2007
Deposits in FDIC and SIPC-insured institutions under insurance limits	$ 588	$ 462
Deposits in FDIC and SIPC-insured institutions over insurance limits	79,387	53,112
Deposits in Foreign Banks	18,805	6,282
	98,780	59,856
Less outstanding checks and other reconciling items	(17,557)	(42,422)
Cash and cash equivalents	$ 81,223	$ 17,434

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 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, 2008, 2007, or 2006. The Company recognized bad debt expense for 2008, 2007 and 2006 of $4.4 million, $2.6 million and $5.4 million, respectively.

The carrying values of cash and cash equivalents, trade receivables and accounts payable approximate fair value due to the short-term maturity of these items.

16. Related Party Transactions

Joint Operation of Oil and Natural Gas Properties Through October 31, 2007, the Company served as operator with respect to several properties and was actively involved in the development, exploration, acquisition and production of oil and natural gas. Effective November 1, 2007, the Company sold the operations portion of its exploration and production business. The Company continues to own and invest in oil and natural gas assets as a working interest owner. During the time that the Company served as operator, it served as operator with respect to certain oil and natural gas properties in which certain of its affiliated persons have participated, either individually or through entities they control. These participations were typically through working interests in prospects or properties originated or acquired by Patterson Petroleum, LLC, a wholly owned subsidiary of Patterson-UTI.

During the time that the Company served as operator, sales of working interests to affiliated parties were made by the Company 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 received oil and natural gas production revenue (net of royalty) of $19.0 million and $15.8 million from these properties in 2007 and 2006, respectively. These persons or entities in turn paid for joint operating costs (including drilling and other development expenses) of $9.2 million and $14.1 million incurred in 2007 and 2006, respectively.

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

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2007				
Operating revenues	$ 547,101	$ 522,558	$ 524,002	$ 520,533
Operating income	179,725	215,136	144,100	131,315
Net income	115,801	139,551	98,181	85,106
Net income per common share:				
Basic	$ 0.75	$ 0.90	$ 0.63	$ 0.56
Diluted	$ 0.73	$ 0.88	$ 0.62	$ 0.55
2008				
Operating revenues	$ 504,554	$ 526,283	$ 608,532	$ 569,757
Operating income	119,874	126,419	165,282	129,955
Net income	77,409	81,422	108,746	79,492
Net income per common share:				
Basic	$ 0.51	$ 0.53	$ 0.70	$ 0.52
Diluted	$ 0.50	$ 0.52	$ 0.70	$ 0.52

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PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

Description	Beginning Balance	Charged to Costs and Expenses	Deductions(1)	Ending Balance
		(In thousands)		
Year Ended December 31, 2008				
Deducted from asset accounts:				
Allowance for doubtful accounts	$ 10,014	$ 4,350	$ 5,034	$ 9,330
Year Ended December 31, 2007				
Deducted from asset accounts:				
Allowance for doubtful accounts	$ 7,484	$ 2,550	$ 20	$ 10,014
Year Ended December 31, 2006				
Deducted from asset accounts:				
Allowance for doubtful accounts	$ 2,199	$ 5,400	$ 115	$ 7,484

(1) Uncollectible accounts written off net of recoveries.

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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/ Douglas J. Wall

Douglas J. Wall
President and Chief Executive Officer

Date: February 18, 2009

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 18, 2009.

Signature	**Title**
/s/ Mark S. Siegel Mark S. Siegel	Chairman of the Board
/s/ Douglas J. Wall Douglas J. Wall *(Principal Executive Officer)*	President and Chief Executive Officer
/s/ John E. Vollmer III John E. Vollmer III *(Principal Financial Officer)*	Senior Vice President Corporate Development, Chief Financial Officer and Treasurer
/s/ Gregory W. Pipkin Gregory W. Pipkin *(Principal Accounting Officer)*	Chief Accounting Officer and Assistant Secretary
/s/ Kenneth N. Berns Kenneth N. Berns	Senior Vice President and Director
/s/ Charles O. Buckner Charles O. Buckner	Director

/s/ Curtis W. Huff	Director
Curtis W. Huff	
/s/ Terry H. Hunt	Director
Terry H. Hunt	
/s/ Kenneth R. Peak	Director
Kenneth R. Peak	
/s/ Cloyce A. Talbott	Director
Cloyce A. Talbott	

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EXHIBIT INDEX

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	Second Amended and Restated Bylaws (filed August 6, 2007 as Exhibit 3.3 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 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	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).*
10.4	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).*
10.5	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).*
10.6	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).*
10.7	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).*
10.8	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 21, 2005 as Exhibit 10.1 to the Company s Current Report on Form 8-K, and incorporated herein by reference).*
10.9	First Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed June 6, 2008 as Exhibit 10.1 to the Company s Current Report on Form 8-K and incorporated herein by reference).
10.10	Second Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed June 6, 2008 as Exhibit 10.2 to the Company s Current Report on Form 8-K and incorporated herein by reference).

10.11	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).*
10.12	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).*

10.13	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, dated as of September 1, 2007 between Patterson-UTI Energy, Inc. and Cloyce A. Talbott (filed on September 24, 2007 as Exhibit 10.1 to the Company s Current Report on Form 8-K, 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 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).*
10.18	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).*
10.19	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).*
10.20	Form of Indemnification Agreement entered into by Patterson-UTI Energy, Inc. with each of Mark S. Siegel, Cloyce A. Talbott, Douglas J. Wall, Kenneth N. Berns, Curtis W. Huff, Terry H. Hunt, Kenneth R. Peak, Charles O. Buckner, John E. Vollmer III, William L. Moll, Jr. and Gregory W. Pipkin (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).*
10.21	Severance Agreement between Patterson-UTI Energy, Inc. and Douglas J. Wall, effective as of August 31, 2007 (filed September 4, 2007 as Exhibit 10.3 to the Company s Current Report on Form 8-K and incorporated herein by reference).*
10.22	Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of August 31, 2007, by and between Patterson-UTI Energy, Inc. and Douglas J. Wall (filed September 4, 2007 as Exhibit 10.2 to the Company s Current Report on Form 8-K and incorporated herein by reference).*
10.23	Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of August 31, 2007, by and between Patterson-UTI Energy, Inc. and William L. Moll, Jr. (filed November 5, 2007 as Exhibit 10.7 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*
10.24	First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and Mark S. Siegel, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.8 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*
10.25	First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and Douglas J. Wall, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.9 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*

10.26	First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and John E. Vollmer, III, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.10 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*
10.27	First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and Kenneth N. Berns, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.11 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*

10.28	First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and William L. Moll, Jr., entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.12 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*
10.29	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).
10.30	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).
10.31	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.