PATTERSON-UTI ENERGY, INC. | 2010 ANNUAL REPORT

COMPANY PROFILE Patterson-UTI Energy, Inc. subsidiaries provide onshore contract drilling and pressure pumping services to exploration and production companies in North America. Patterson-UTI Drilling Company LLC has approximately 350 marketable land-based drilling rigs that operate primarily in the oil and natural gas producing regions of Texas, New Mexico, Oklahoma, Arkansas, Louisiana, Mississippi, Colorado, Utah, Wyoming, Montana, North Dakota, Pennsylvania, West Virginia and western Canada. Universal Pressure Pumping, Inc. and Universal Well Services, Inc. provide pressure pumping services primarily in Texas and the Appalachian Basin.

Financial Highlights

(in thousands, except per share amounts – unaudited)

	Year Ended December 31,				
	2006	2007	2008	2009	2010
Revenues	$2,354,228	$1,986,096	$2,063,880	$ 781,946	$1,462,931
Operating income (loss)	1,010,319	663,310	545,933	(48,214)	200,925
Net income (loss)	673,254	438,639	347,069	(38,290)	116,942
Net income (loss) per share					
Basic	4.05	2.81	2.25	(0.25)	0.76
Diluted	4.00	2.78	2.23	(0.25)	0.76
Cash dividends per share	0.28	0.44	0.60	0.20	0.20
Total assets	2,192,503	2,465,199	2,712,817	2,662,152	3,423,031
Borrowings under revolving credit facility	120,000	50,000	—	—	—
Long-term debt	—	—	—	—	392,500
Stockholders' equity	1,562,466	1,896,030	2,126,942	2,081,700	2,187,607
Working capital	334,429	226,209	337,615	263,511	241,445

Operational Highlights

(dollars in thousands – unaudited)

	2006	2007	2008	2009	2010
Contract Drilling:					
Revenues	$2,169,370	$1,741,647	$1,804,026	$ 599,287	$1,081,898
Average revenue per day	$ 20.05	$ 19.55	$ 19.38	$ 17.95	$ 17.67
Average direct operating costs per day	$ 9.26	$ 10.81	$ 11.16	$ 10.71	$ 10.71
Average margin per day (1)	$ 10.79	$ 8.74	$ 8.22	$ 7.24	$ 6.96
Operating days	108,192	89,095	93,068	33,394	61,244
Average rigs operating during the year	296	244	254	91	168
Number of rigs operated during the year	331	338	315	243	220
Number of wells drilled during the year	5,050	4,237	4,218	1,539	2,919
Pressure Pumping:					
Revenues	$ 145,671	$ 202,812	$ 217,494	$ 161,441	$ 350,608
Average revenue per fracturing job	$ 33.19	$ 40.62	$ 49.62	$ 70.88	$ 180.21
Average revenue per other job	$ 6.61	$ 7.16	$ 8.04	$ 9.17	$ 12.47
Average revenue per total job	$ 13.51	$ 15.56	$ 18.03	$ 23.14	$ 46.29
Average direct operating costs per total job	$ 7.93	$ 9.00	$ 12.22	$ 17.78	$ 31.04
Average margin per total job (1)	$ 5.58	$ 6.57	$ 5.81	$ 5.35	$ 15.25
Number of fracturing jobs	2,797	3,274	2,898	1,579	1,527
Number of other jobs	7,986	9,757	9,162	5,399	6,047
Total number of jobs	10,783	13,031	12,060	6,978	7,574
Quintiplex fracturing horsepower at end of year	—	—	11,250	45,000	226,750
Triplex fracturing horsepower at end of year	43,200	67,200	79,200	82,800	126,850
Other pumping equipment horsepower at end of year	22,200	28,200	32,400	35,400	81,600
Total hydraulic horsepower at end of year	65,400	95,400	122,850	163,200	435,200

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

PATTERSON-UTI ENERGY INC.

CONTRACT DRILLING

We have made significant upgrades over the last several years to our drilling fleet to match the needs of our customers. While conventional wells remain an important source of natural gas and oil, our customers have expanded the development of shale and other unconventional wells to help supply the long-term demand for natural gas and oil in North America.

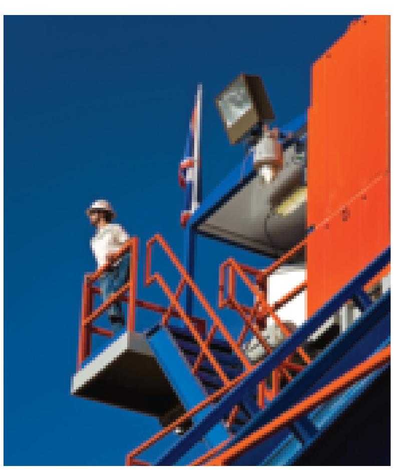
To address our customers' needs for drilling wells in the newer horizontal shale and other unconventional "resource plays", we have expanded our areas of operations and improved the capability of our drilling fleet. We have continued to deliver new APEX™ rigs to the market and make performance and safety improvements to existing high-capacity rigs. In 2010, we added 19 new APEX™ rigs to our fleet consisting of nine APEX™ 1500, five APEX™ 1000 and five APEX™ Walking rigs. In addition, we plan to complete 25 new APEX™ rigs in 2011.

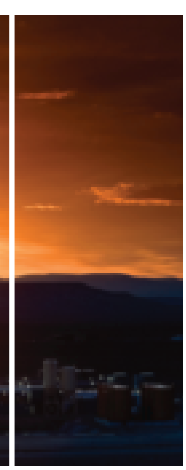
APEX™ 1500s are 1,500HP electric rigs with advanced EDS systems, 500 ton top drives, iron roughnecks, hydraulic catwalks, and other highly automated pipe handling equipment. APEX™ 1000s are 1,000HP electric rigs with advanced technology equipment similar to the APEX™ 1500s, but with a more compact design to fit on smaller locations, such as for drilling Marcellus Shale wells in Appalachia. APEX™ Walking rigs are designed to efficiently drill multiple wells from a single pad, by "walking" between the wellbores without requiring time to lower the mast and remove the drill pipe.

Additionally, to meet the needs of the increased demand for drilling horizontal wells, we have continued to acquire top drives and improve the capability of many of our non-APEX™ rigs to efficiently drill these wells. We are a major participant in significant unconventional "resource plays" in the United States.

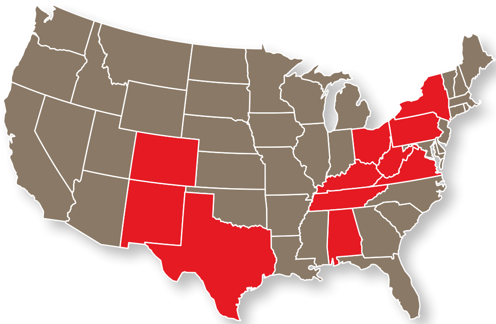
We also remain a market leader in the drilling of conventional wells of varying depths. Over the last several years we have made substantial improvements to our overall drilling fleet to improve the drilling efficiency of these wells. Improvements have included higher capacity pumps, high-efficiency mud systems and iron roughnecks.

As of the end of 2010, we had 356 marketable land drilling rigs of which 80% had depth capacities ranging from 12,000 to 30,000 feet.





PRESSURE PUMPING



Our pressure pumping businesses, Universal Pressure Pumping, Inc. and Universal Well Services, Inc., are adding capacity as a result of increased demand for our services as customers expand development of shale, liquids-rich and oil reserves. The primary source of revenues for this business segment is fracturing services. Other services provided include cementing, acidizing, nitrogen vaporization and flowback testing.

Our coverage of shale basins includes the Marcellus in the Appalachian region, the Eagle Ford in South Texas and the Barnett in North Texas. Our pressure pumping operations also extend to the oily Permian basin in West Texas and New Mexico. These businesses have a long-standing presence in most of these areas, which gives us a home field advantage as development increases.

Our total hydraulic pumping horsepower has increased more than 550% over the past four years to approximately 435,000 as of December 31, 2010. This growth was accomplished through the purchase of new-build equipment and through the acquisition, during the fourth quarter of 2010, of the assets which are operated by Universal Pressure Pumping, Inc. New-build additions included quintiplex frac pumpers, 140 BPM blenders, and satellite equipped frac vans which allow efficient completion of complex shale frac jobs. Also, we plan to add approximately 200,000 hydraulic horsepower of pumping capacity in 2011.

As the country continues to recognize and develop the huge energy resources available on land in the U.S., we expect the pressure pumping industry will continue its growth. We have a strong and deep foundation from which to grow each part of our services and take full advantage of the many opportunities that are presented to us.

Financial Review

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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2010

or

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

For the transition period from to

Commission File Number 0-22664

Patterson-UTI Energy, Inc.

(Exact name of registrant as specified in its charter)

Delaware *(State or other jurisdiction of incorporation or organization)*	**75-2504748** *(I.R.S. Employer Identification No.)*
450 Gears Road, Suite 500, Houston, Texas *(Address of principal executive offices)*	**77067** *(Zip Code)*

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

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

Title of Each Class	Name of Exchange on Which Registered
Common Stock, $0.01 Par Value	The Nasdaq Global Select Market
Preferred Share Purchase Rights	The Nasdaq Global Select Market

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ or No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, 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 ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐
(Do not check if a smaller reporting company)

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2010, the last business day of the registrant's most recently completed second fiscal quarter, was $1,948,746,558, calculated by reference to the closing price of $12.87 for the common stock on the Nasdaq Global Select Market on that date.

As of February 11, 2011, the registrant had outstanding 154,203,597 shares of common stock, $.01 par value, its only class of common stock.

Documents incorporated by reference:

Portions of the registrant's definitive proxy statement for the 2011 Annual Meeting of Stockholders are incorporated by reference into Part III of this report.

DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this "Report") and other public filings and press releases by us contain "forward-looking statements" within the meaning of the Securities Act of 1933, as amended (the "Securities Act"), the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and the Private Securities Litigation Reform Act of 1995, as amended. These "forward-looking statements" involve 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 building new equipment and additional acquisitions (if further opportunities arise); impact of inflation; demand for our services; 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," "continue," "expects," "estimates," "project," "will," "could," "may," "plans," "intends," "strategy," or "anticipates," or the negative thereof 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 orally or in writing, including, but not limited to, Management's Discussion and Analysis of Financial Condition and Results of Operations included in this Report and other sections of our filings with the United States Securities and Exchange Commission (the "SEC") under the Exchange Act and the Securities Act.

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 rates, utilization, margins and planned capital expenditures, excess availability of land drilling rigs and pressure pumping equipment, including as a result of reactivation or construction, adverse industry conditions, adverse credit and equity market conditions, difficulty in integrating acquisitions, shortages of equipment and materials, governmental regulation and ability to retain management and field personnel. Refer to "Risk Factors" contained in Part 1 of this Report for a more complete discussion of these and other factors that might affect our performance and financial results. You are cautioned not to place undue reliance on any of our forward-looking statements. 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, changes in internal estimates or otherwise.

PART I

Item 1. *Business*

Available Information

This Report, 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 Exchange Act, 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

We own and operate one of the largest fleets of land-based drilling rigs in the United States. The Company was formed in 1978 and reincorporated in 1993 as a Delaware corporation. Our contract drilling business operates primarily in Texas, New Mexico, Oklahoma, Arkansas, Louisiana, Mississippi, Colorado, Utah, Wyoming, Montana, North Dakota, Pennsylvania, West Virginia and western Canada.

As of December 31, 2010, we had a drilling fleet that consisted of 356 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 drill pipe and drilling rig components.

We provide pressure pumping services to oil and natural gas operators primarily in Texas and the Appalachian Basin. Pressure pumping services consist primarily of well stimulation and cementing for completion of new wells and remedial work on existing wells. We also own and invest in oil and natural gas assets as a working interest owner. Our oil and natural gas working interests are located primarily in Texas and New Mexico.

Prior to January 20, 2010, we provided 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 sold our drilling and completion fluids services business on January 20, 2010.

On October 1, 2010 we acquired the assets and operations of a pressure pumping business and an electric wireline business. The electric wireline business that we acquired was classified as held for sale at December 31, 2010 and sold on January 27, 2011. The results of our drilling and completion fluids services business and our electric wireline business are presented as discontinued operations in this Report.

Industry Segments

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

- contract drilling services,
- pressure pumping services, and
- oil and natural gas exploration and production.

All of our industry segments had operating profits in 2010 and 2008. In 2009, our pressure pumping services and oil and natural gas exploration and production segments had operating profits and our contract drilling services segment had an operating loss.

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

Contract Drilling Operations

General — We market our contract drilling services to major and independent oil and natural gas operators. As of December 31, 2010, we had 356 marketable land-based drilling rigs based in the following regions:

- 73 in west Texas and southeastern New Mexico,
- 97 in north central and east Texas, northern Louisiana and Mississippi,
- 58 in the Rocky Mountain region (Colorado, Utah, Wyoming, Montana and North Dakota),
- 51 in south Texas and southern Louisiana,
- 32 in the Texas panhandle, Oklahoma and Arkansas,
- 25 in the Appalachian Basin, and
- 20 in western Canada.

Our marketable drilling rigs have rated maximum depth capabilities ranging from 5,000 feet to 25,000 feet. Of these drilling rigs, 124 are electric rigs and 232 are mechanical rigs. An electric rig differs from a mechanical rig in that the electric rig converts the diesel power (the sole energy source for a mechanical rig) into electricity to power the rig. We also have a substantial inventory of drill pipe and drilling rig components, 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 2010, 2009 and 2008, we spent approximately $656 million, $395 million and $361 million, respectively, on these capital expenditures.

Depth and complexity of the well and drill site conditions are the principal factors in determining the specifications of the rig selected for a particular job.

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 2010, our average number of days to drill a well (which includes moving to the drill site, rigging up and rigging down) was approximately 21 days.

Our 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. Generally, we 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. Generally, the customers indemnify us against claims that might arise from other surface and subsurface pollution. Each drilling contract contains the actual terms setting forth our rights and obligations and those of the customer, any of which rights and obligations may deviate from what is customary due to industry conditions or other factors.

Our drilling contracts provide for payment on a daywork, footage or turnkey basis, or a combination thereof. In each case, we provide the rig and crews. Our bid for each job 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.

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. Except for two wells drilled under footage contracts in 2009, all of the wells we drilled in 2010, 2009 and 2008 were under daywork 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-upon depth. If we drill the well in less time than estimated, we have the opportunity to improve our profits over those that would be attainable under a daywork contract. Profits are reduced and losses may be incurred if the well requires more days to drill to the contracted depth than estimated. Footage contracts generally contain greater risks for a drilling contractor than daywork contracts. Under footage contracts, the drilling contractor typically assumes certain risks associated with loss of the well from fire, blowouts and other risks. We drilled two wells under footage contracts in 2009, and we did not drill any wells under footage contracts in 2010 or 2008.

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- upon 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. Although we have entered into turnkey contracts in the past, 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,		
	2010	**2009**	**2008**
Average rigs operating per day(1)	168	91	254
Number of rigs operated during the year	220	243	315
Number of wells drilled during the year	2,919	1,539	4,218
Number of operating days(2)	61,244	33,394	93,068

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

(2) Includes standby days under term contracts where revenue was earned but the rig was not working. The number of these standby days under term contracts was zero in 2010, 2,070 in 2009 and 486 in 2008.

Drilling Rigs and Related Equipment — We estimate the depth capacity with respect to our marketable rigs as of December 31, 2010 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	59	9	68
12,000 to 15,999	193	8	201
16,000 to 25,000	84	—	84
Totals	336	20	356

At December 31, 2010, we owned and operated 317 trucks and 402 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 generally 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, Oklahoma, Wyoming, Utah, Pennsylvania and western Canada.

Pressure Pumping Operations

General — We provide pressure pumping services to oil and natural gas operators primarily in Texas and the Appalachian Basin. Pressure pumping services consist of well stimulation and cementing for the completion of new wells and remedial work on existing wells. Wells drilled in shale formations and other unconventional plays require well stimulation through fracturing to allow the flow of oil and natural gas. This is accomplished by pumping fluids under pressure into the well bore to fracture the formation. Many wells in conventional plays also receive well stimulation services. The cementing process inserts material between the wall of the well bore and the casing to support and stabilize the casing.

Equipment — Our pressure pumping equipment at December 31, 2010 includes equipment used in providing hydraulic and nitrogen fracturing services as well as nitrogen, cementing and acid pumping services as follows:

	Quintiplex Fracturing Equipment	Triplex Fracturing Equipment	Other Pumping Equipment	Total
Number of Units	101	90	130	321
Approximate Hydraulic Horsepower	226,750	126,850	81,600	435,200

Our pressure pumping operations are supported by a fleet of equipment including blenders, tractors, manifold trailers and numerous trailers for transportation of materials to and from the worksite as well as bins for storage of materials at the worksite.

Oil and Natural Gas Interests

We own and invest in oil and natural gas assets as a working interest owner. Our oil and natural gas working interests are located primarily in producing regions of Texas and New Mexico.

Customers

The customers of each of our contract drilling and pressure pumping business segments are oil and natural gas operators. Our customer base includes both major and independent oil and natural gas operators. During 2010, no single customer accounted for 10% or more of our consolidated operating revenues.

Competition

Our contract drilling and pressure pumping businesses are highly competitive. Historically, available equipment used in these businesses has frequently exceeded demand in our markets. The price for our services is a key competitive factor in our markets, in part because equipment used in our businesses can be moved from one area to another in response to market conditions. In addition to price, we believe availability and condition of equipment, quality of personnel, service quality and safety record are key factors in determining which contractor is awarded a job in the markets in which we operate. We expect that the market for land drilling and pressure pumping services will continue to be highly competitive.

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,
- the relationships with our employees,
- containment and disposal of hazardous materials, oilfield waste, other waste materials and acids,
- use of underground storage tanks,
- use of underground injection wells, and
- hydraulic fracturing and related activities.

To date, applicable environmental laws and regulations in the United States and Canada have not required the expenditure of significant resources outside the ordinary course of business. 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, and otherwise have an adverse effect on our operations. Federal, state, foreign and local environmental laws and regulations currently apply to our operations and may become more stringent in the future. Any suspension or moratorium of the services we provide, whether or not short-term in nature, by a Federal, state, foreign or local governmental authority, could have a material adverse effect on our business, financial condition and results of operation.

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, which may have resulted, or may result, in soil and groundwater contamination in certain locations. Any contamination found on, under or originating from the properties may be subject to remediation requirements under Federal, state, foreign and local laws and regulations. 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. We could be required to remove or remediate wastes disposed of or released by prior owners or operators. In addition, it is possible we could be held responsible for oil and natural gas properties in which we own an interest but are not the operator.

Some of the environmental laws and regulations that are applicable to our business operations are discussed in the following paragraphs, but the discussion does not cover all environmental laws and regulations that govern our operations.

In the United States, 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 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. 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 activities include the performance of hydraulic fracturing services to enhance the production of oil and natural gas from formations with low permeability, such as shales. Due to concerns raised relating to potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the Federal level and in some states have been initiated to render permitting and compliance requirements more stringent for hydraulic fracturing or prohibit the activity altogether. Such efforts could have an adverse effect on oil and natural gas production activities, which in turn could have an adverse effect on the hydraulic fracturing services that we render for our exploration and production customers.

In Canada, a variety of Canadian federal, provincial and municipal laws and regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and wastes and in connection with spills, releases and emissions of various substances to the environment. These laws and regulations also require that facility sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, new projects or changes to existing projects may require the submission and approval of environmental assessments or permit applications. These laws and regulations are subject to frequent change, and the clear trend is to place increasingly stringent limitations on activities that may affect the environment.

Our operations are also subject to Federal, state, foreign and local laws, rules and regulations for the control of air emissions, including the Federal Clean Air Act and the Canadian Environmental Protection Act. We are aware of the increasing focus of local, state, national and international regulatory bodies on greenhouse gas (GHG) emissions and climate change issues. We are also aware of legislation proposed by United States lawmakers and the Canadian legislature to reduce GHG emissions, as well as GHG emissions regulations enacted by the U.S. Environmental Protection Agency and the Canadian provinces of Alberta and British Columbia. We will continue to monitor and assess any new policies, legislation or regulations in the areas where we operate to determine the impact of GHG emissions and climate change on our operations and take appropriate actions, where necessary. Any direct and indirect costs of meeting these requirements may adversely affect our business, results of operations and financial condition.

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 and other 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, including through:

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

We maintain insurance coverage of types and amounts that we believe to be customary in the industry, but we are not fully insured against all risks, either because insurance is not available or because of the high premium costs. Such risks include personal injury, well disasters, extensive fire damage, damage to the environment, and other hazards. The insurance coverage that we maintain includes insurance for fire, windstorm and other risks of physical loss to our rigs and other assets, employer's liability, automobile liability, commercial general liability insurance, and workers compensation insurance. We cannot assure, however, that any insurance obtained by us will be adequate to cover any losses or liabilities, or that this insurance will continue to be available or available on terms that are acceptable to us. While we carry insurance to cover physical damage to, or loss of, our drilling rigs and other assets, such insurance does not cover the full replacement cost of the rigs or other assets, and we do not carry insurance against loss of earnings resulting from such damage. Liabilities for which we are not insured, or which exceed the policy limits of our applicable insurance, could have a material adverse effect on our financial condition and results of operations.

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. There is no assurance that we will obtain such contractual indemnity, and if obtained, whether such indemnity will be enforceable, whether the customer will be able to satisfy such indemnity or whether such indemnity will be supported by adequate insurance maintained by the customer.

Employees

We had approximately 7,000 full-time employees at December 31, 2010. 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, to a lesser extent, our pressure pumping operations in the Appalachian Basin, are subject to slow periods of activity during the annual Spring thaw.

Raw Materials and Subcontractors

We use many suppliers of raw materials and services. Although, these materials and services have historically been available, 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.

Beginning in late 2008 and continuing through 2009, there was a substantial deterioration in the global economic environment. As part of this deterioration, there was substantial uncertainty in the capital markets and access to financing was reduced. Due to these conditions, our customers reduced or curtailed their drilling programs, which resulted in a decrease in demand for our services. Furthermore, these factors resulted in certain of our customers experiencing an inability to pay suppliers, including us. Although the significant deterioration in the global economic environment appeared to stabilize to some degree during 2010, there is no assurance that the global economic environment could not quickly deteriorate again due to one or more factors. A return of the conditions causing a deterioration in the global economic environment 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 cash flows are highly dependent upon prevailing prices for natural gas and 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 (monthly average Henry Hub price as reported by the Energy Information Administration) peaked in June at $13.06 per Mcf before rapidly declining to an average of $5.99 per Mcf in December. In 2009, the monthly average market price of natural gas declined further to a low of $3.06 per Mcf in September. The monthly average market price of natural gas has not recovered to levels experienced during early 2008 and was $4.38 per Mcf in December 2010. This volatility and the extended declines in the market price of natural gas resulted in our customers significantly reducing their drilling activities beginning in the fourth quarter of 2008, and drilling activities remained low through 2009 before increasing somewhat in 2010. The increase in 2010 can be attributed partially to increased activity in oil rich basins as a result of the growing development of unconventional oil reservoirs and an improvement in the price of oil compared to 2009. Although our average number of rigs operating increased during 2010, it remains well below the number of our available rigs. Construction of new land drilling rigs in the United States during the last ten years has significantly contributed to excess capacity. As a result of decreased drilling activity and excess capacity, our average number of rigs operating has declined significantly from historic highs. 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. Low market prices for natural gas and oil would likely result in low demand for our drilling rigs and pressure pumping services and would adversely affect our operating results, financial condition and cash flows.

A General Excess of Operable Land Drilling Rigs, Increasing Rig Specialization and Excess Pressure Pumping Equipment May Adversely Affect Our Utilization and Profit Margins.

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 and, at times, have sustained losses during the downturn periods.

In addition, unconventional resource plays have substantially increased recently and some drilling rigs are not capable of drilling these wells efficiently. Accordingly, the utilization of some older technology drilling rigs may be hampered by their lack of capability to successfully compete for this work. Other 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.

Construction of new drilling rigs increased significantly during the last ten years. The addition of new drilling rigs to the market and the recent decrease in demand has resulted in excess capacity. Similarly, the substantial recent increase in unconventional resource plays has led to higher demand for pressure pumping services. As a result, we believe there has been, and we expect there to continue to be, a significant increase in the construction of new pressure pumping equipment. The addition of new pressure pumping equipment, as well as any general decline in demand for pressure pumping services, could result in there being substantially more pressure pumping equipment available than necessary to meet demand. If this were to occur, providers of pressure pumping services will have difficulty sustaining profit margins and may sustain losses during downturn periods. We cannot predict either the future level of demand for our contract drilling or pressure pumping services or future conditions in the oil and natural gas contract drilling or pressure pumping businesses.

Shortages of Drill Pipe, Replacement Parts, Other Equipment and Materials Adversely Affect Our Operating Results.

During periods of increased demand for drilling and pressure pumping services, the industry has experienced shortages of drill pipe, replacement parts, other equipment and materials, including proppants and gels for our pressure pumping operations. 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. In addition, any interruption in supply due to vendor or other issues could result in significant delays in delivery of equipment and materials or prevent operations. These price increases and delays in delivery may require us to increase capital and repair expenditures and incur higher operating costs. Severe shortages or delays in delivery could limit our ability to operate our drilling rigs and pressure pumping equipment.

The Oil Service Business Segments in Which We Operate Are Highly Competitive with Excess Capacity, which Adversely Affects 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 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.

Labor Shortages and Rising Labor Costs 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.

Growth Through the Building of New Rigs and Pressure Pumping Equipment and Rig and Other Acquisitions are Not Assured.

We have increased our drilling rig fleet and pressure pumping horsepower in the past through mergers, acquisitions and new construction. The land drilling and pressure pumping industries have experienced significant consolidation, and there can be no assurance that acquisition opportunities will be available in the future. We are also likely to continue to face intense competition from other companies for available acquisition opportunities. In addition, because improved technology has enhanced the ability to recover oil and natural gas, contract drillers may continue to build new, high technology rigs and providers of pressure pumping services may continue to build new, high horsepower equipment.

There can be no assurance that we will:

- have sufficient capital resources to complete additional acquisitions or build new rigs or pressure pumping equipment,

- successfully integrate additional drilling rigs, pressure pumping equipment or other assets,
- effectively manage the growth and increased size of our organization, drilling fleet and pressure pumping equipment,
- successfully deploy idle, stacked or additional rigs and pressure pumping equipment,
- maintain the crews necessary to operate additional drilling rigs and pressure pumping equipment, or
- successfully improve our financial condition, results of operations, business or prospects as a result of any completed acquisition or the building of new drilling rigs and pressure pumping equipment.

We may incur substantial indebtedness to finance future acquisitions, build new drilling rigs or build new pressure pumping equipment and also may issue equity, convertible or debt securities in connection with any such acquisitions or building program. 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 and pressure pumping 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 be enforceable or 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. It is possible that a customer or insurer could fail or be unable to meet its indemnification or insurance obligations, which could result in a material loss. Moreover, we could suffer a material loss if we were to become subject to an unexpected judgment against us for which we are uninsured, for which indemnification is unenforceable or otherwise not available or that is beyond the amounts we reserved or anticipated incurring. Incurring a liability for which we are not fully insured or indemnified could materially affect our business, financial condition and results of operations.

We have also elected in some cases to accept a greater amount of risk through increased deductibles on certain insurance policies. For example, we generally maintain a $1.0 million per occurrence deductible on our workers' compensation and equipment insurance coverages and a $2.0 million per occurrence self insured retention on our general liability insurance coverage.

Difficulties Integrating Our Recently Acquired Pressure Pumping Assets Could Adversely Affect Our Operating Results.

We expect that our recently acquired pressure pumping assets will complement and expand our business. Successfully integrating the acquired business depends on our ability to integrate the acquired assets and personnel and to maintain and grow the acquired customer base. We may encounter challenges in integrating the acquired business with our existing operations and management. We may not be able to fully take advantage of expected business opportunities, including successfully developing new markets and retaining acquired customers. The integration of the new business may place additional strain on our management. In addition, the acquired business may not achieve anticipated results. If the acquired business is not successfully integrated, our operating results could be adversely affected.

We are Dependent Upon our Subsidiaries to Meet our Obligations Under our Long Term Debt

We have borrowings outstanding under a term loan and our senior notes. These obligations are guaranteed by each of our existing subsidiaries other than immaterial subsidiaries. Our ability to meet our interest and principal payment obligations depends in large part on dividends paid to us by our subsidiaries. If our subsidiaries do not generate sufficient cash flows to pay us dividends, we may be unable to meet our interest and principal payment obligations.

Environmental Laws and Regulations, Including Violations Thereof Could Materially Adversely Affect Our Operating Results.

All of our operations and facilities are subject to numerous Federal, state, foreign and local 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. 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, environmental laws and regulations in the United States and Canada impose a variety of requirements 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 and pressure pumping equipment, we may be deemed to be a responsible party under these laws and regulations.

Potential Legislation and Regulation Covering Hydraulic Fracturing Could Increase Our Costs and Result in Operational Delays.

Members of the U.S. Congress and the U.S. Environmental Protection Agency (the "EPA") are reviewing more stringent regulation of hydraulic fracturing, a technology employed by our pressure pumping business, which involves the injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production. Both the EPA and the U.S. Congress are studying whether there is any link between hydraulic fracturing activities and soil or ground water contamination. As part of their respective studies, the House Subcommittee on Energy and Environment and the EPA each sent requests to a number of companies, including our company for information on their hydraulic fracturing practices. We have responded to each of the inquiries. In addition, legislation has been proposed in the U.S. Congress to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process are impairing ground water or causing other damage. These bills, if adopted, could establish an additional level of regulation at the federal or state level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business. Certain states have adopted or are considering similar disclosure legislation. Additional regulation could increase the costs of conducting our business and could materially reduce our business opportunities and revenues if our customers decrease their levels of activity in response to such regulation.

Legislation and Regulation of Greenhouse Gases Could Adversely Affect our Business

We are aware of the increasing focus of local, state, national and international regulatory bodies on GHG emissions and climate change issues. We are also aware of legislation proposed by United States lawmakers and the Canadian legislature to reduce GHG emissions, as well as GHG emissions regulations enacted by the EPA and the Canadian provinces of Alberta and British Columbia. In 2007, the U.S. Supreme Court in *Massachusetts, et al. v. Environmental Protection Agency* held that carbon dioxide, a GHG, may be regulated as an "air pollutant" under the Clean Air Act, which could result in future regulations even if the U.S. Congress does not enact new legislation regarding such emissions. We will continue to monitor and assess any new policies, legislation or regulations in the areas where we operate to determine the impact of GHG emissions and climate change on our operations and take appropriate actions, where necessary. Any direct and indirect costs of meeting these requirements may adversely affect our business, results of operations and financial condition.

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. 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 comprises approximately 12,000 square feet of leased office space, and is located at 450 Gears Road, Suite 500, Houston, Texas. 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.

Contract Drilling Operations — Our drilling services are supported by several offices and yard facilities located throughout our areas of operations, including Texas, New Mexico, Oklahoma, Colorado, Utah, Wyoming, Pennsylvania and western Canada.

Pressure Pumping — Our pressure pumping services are supported by several offices and yard facilities located throughout our areas of operations including Texas, Pennsylvania, Ohio, West Virginia, Kentucky, Tennessee and Colorado.

Oil and Natural Gas Working Interests — Our interests in oil and natural gas properties are primarily located in Texas and New Mexico.

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. *(Removed and Reserved).*

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 Global Select 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
2009:		
First quarter	$13.50	$ 7.49
Second quarter	15.95	8.56
Third quarter	15.98	11.38
Fourth quarter	18.07	14.20
2010:		
First quarter	$18.67	$13.19
Second quarter	16.15	11.85
Third quarter	17.42	12.52
Fourth quarter	22.67	16.59

(b) Holders

As of February 11, 2011, there were approximately 1,500 holders of record of our common stock.

(c) Dividends

We paid cash dividends during the years ended December 31, 2009 and 2010 as follows:

	Per Share	Total (in thousands)
2009:		
Paid on March 31, 2009	$0.05	$ 7,655
Paid on June 30, 2009	0.05	7,675
Paid on September 30, 2009	0.05	7,675
Paid on December 30, 2009	0.05	7,676
Total cash dividends	$0.20	$30,681
2010:		
Paid on March 30, 2010	$0.05	$ 7,677
Paid on June 30, 2010	0.05	7,706
Paid on September 30, 2010	0.05	7,704
Paid on December 30, 2010	0.05	7,709
Total cash dividends	$0.20	$30,796

On February 2, 2011, 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 30, 2011 to holders of record as of March 15, 2011. 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.

(d) Securities Authorized for Issuance Under Equity Compensation Plans

Equity compensation plan information as of December 31, 2010 follows:

	Equity Compensation Plan Information		
Plan Category	**Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights**	**Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights**	**Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans (Excluding Securities Reflected in Column(a))**
	(a)	**(b)**	**(c)**
Equity compensation plans approved by security holders(1)	7,541,550	$19.78	5,763,314
Equity compensation plans not approved by security holders(2)	168,552	$10.23	—
Total	7,710,102	$19.58	5,763,314

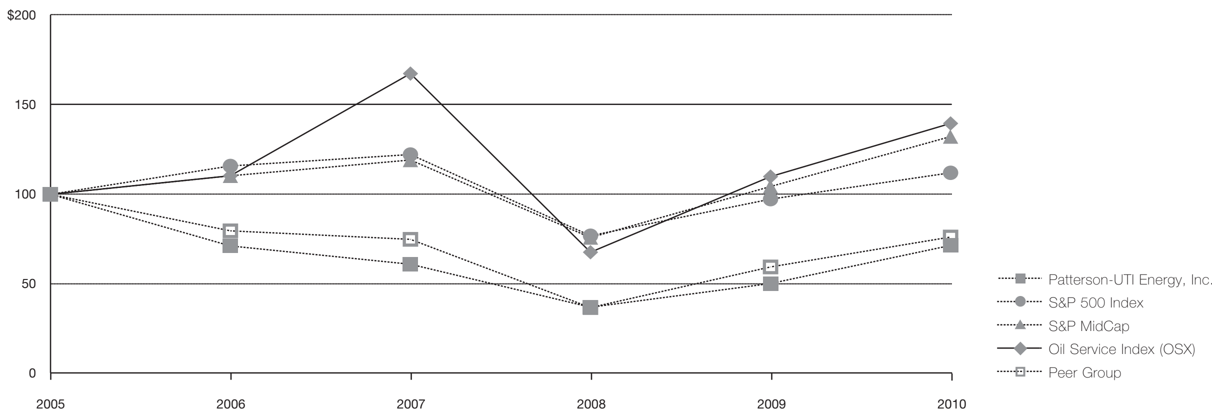
(1) The Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan, as amended (the "2005 Plan"), provides for awards of incentive stock options, non-incentive stock options, tandem and freestanding stock appreciation rights, restricted stock awards, other stock unit awards, performance share awards, performance 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 2001 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.

(e) Performance Graph

The following graph compares the cumulative stockholder return of our common stock for the period from December 31, 2005 through December 31, 2010, 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 peer group consists of BJ Services Company, Bronco Drilling Company, Inc., Helmerich & Payne, Inc., Nabors Industries, Ltd., Pioneer Drilling Co., Precision Drilling Corp and Superior Well Services, Inc. All of the companies in our peer group are providers of land-based drilling or pressure pumping services. BJ Services Company and Superior Well Services, Inc. were acquired by Baker Hughes, Inc. and Nabors Industries, Ltd., respectively during 2010. The graph assumes investment of $100 on December 31, 2005 and reinvestment of all dividends.

Comparison of Cumulative Total Return
(in dollars)



Company/Index	Fiscal Year Ended December 31, 2005 ($)	2006 ($)	2007 ($)	2008 ($)	2009 ($)	2010 ($)
Patterson-UTI Energy, Inc.	100.00	71.28	61.09	37.17	50.37	71.56
Peer Group Index	100.00	79.68	74.95	36.97	59.59	76.24
S&P 500 Stock Index	100.00	115.79	122.16	76.96	97.33	111.99
Oilfield Service Index (OSX)	100.00	110.35	167.21	67.77	109.89	139.47
S&P MidCap Index	100.00	110.32	119.12	75.96	104.36	132.16

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.

Item 6. *Selected Financial Data.*

Our selected consolidated financial data as of December 31, 2010, 2009, 2008, 2007 and 2006, and for each of the five years in the period ended December 31, 2010 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 2010 presentation. Due to the sale of our drilling and completion fluids business in January 2010 and the sale of our electric wireline business in January

2011, the results of operations for those businesses have been reclassified and are presented as discontinued operations in all periods presented below.

	Years Ended December 31,				
	2010	2009	2008	2007	2006
	(In thousands, except per share amounts)				
Statement of Operations Data:					
Operating revenues:					
Contract drilling	$1,081,898	$ 599,287	$1,804,026	$1,741,647	$2,169,370
Pressure pumping	350,608	161,441	217,494	202,812	145,671
Oil and natural gas	30,425	21,218	42,360	41,637	39,187
Total	1,462,931	781,946	2,063,880	1,986,096	2,354,228
Operating costs and expenses:					
Contract drilling	655,678	357,742	1,038,327	963,150	1,002,001
Pressure pumping	235,100	124,100	147,377	117,250	85,529
Oil and natural gas	7,020	7,341	12,793	10,864	13,374
Depreciation, depletion, amortization and impairment	333,493	289,847	275,990	246,346	193,664
Selling, general and administrative	53,042	43,935	43,273	42,688	36,770
Net (gain) loss on asset disposals	(22,812)	3,385	(4,163)	(16,432)	3,905
Provision for bad debts	(2,000)	3,810	4,350	2,875	5,585
Embezzlement costs (recoveries)	—	—	—	(43,955)	3,081
Acquisition-related expenses	2,485	—	—	—	—
Total	1,262,006	830,160	1,517,947	1,322,786	1,343,909
Operating income (loss)	200,925	(48,214)	545,933	663,310	1,010,319
Other income (expense)	(10,171)	(3,341)	1,425	527	4,657
Income (loss) from continuing operations before income taxes	190,754	(51,555)	547,358	663,837	1,014,976
Income tax expense (benefit)	72,856	(17,595)	193,490	229,350	360,639
Income (loss) from continuing operations	$ 117,898	$ (33,960)	$ 353,868	$ 434,487	$ 654,337
Income (loss) from continuing operations per common share:					
Basic	$ 0.77	$ (0.22)	$ 2.29	$ 2.78	$ 3.94
Diluted	$ 0.76	$ (0.22)	$ 2.27	$ 2.75	$ 3.89
Cash dividends per common share	$ 0.20	$ 0.20	$ 0.60	$ 0.44	$ 0.28
Weighted average number of common shares outstanding:					
Basic	152,772	152,069	153,379	154,755	165,159
Diluted	153,276	152,069	154,358	156,612	167,200
Balance Sheet Data:					
Total assets	$3,423,031	$2,662,152	$2,712,817	$2,465,199	$2,192,503
Borrowings under line of credit	—	—	—	50,000	120,000
Long term debt (including current maturities)	398,750	—	—	—	—
Stockholders' equity	2,187,607	2,081,700	2,126,942	1,896,030	1,562,466
Working capital	241,445	263,511	337,615	226,209	334,429

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

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, pressure pumping 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, 2010, our operating revenues consisted of the following (dollars in thousands):

	2010		2009		2008	
Contract drilling	$1,081,898	74%	$599,287	76%	$1,804,026	87%
Pressure pumping	350,608	24	161,441	21	217,494	11
Oil and natural gas	30,425	2	21,218	3	42,360	2
	$1,462,931	100%	$781,946	100%	$2,063,880	100%

We provide our contract services to oil and natural gas operators in many of the oil and natural gas producing regions of North America. Our contract drilling operations are focused in various regions of Texas, New Mexico, Oklahoma, Arkansas, Louisiana, Mississippi, Colorado, Utah, Wyoming, Montana, North Dakota, Pennsylvania, West Virginia and western Canada, while our pressure pumping services are focused primarily in Texas and the Appalachian Basin. The oil and natural gas properties in which we hold interests are primarily located in Texas and New Mexico.

Generally, the profitability of our business is impacted most by two primary factors in our contract drilling segment: our average number of rigs operating and our average revenue per operating day. During 2010, our average number of rigs operating was 168 compared to 91 in 2009 and 254 in 2008. Our average revenue per operating day was $17,670 in 2010 compared to $17,950 in 2009 and $19,380 in 2008. We had consolidated net income of $117 million for 2010 compared to a consolidated net loss of $38.3 million for 2009. The increase in consolidated net income was primarily due to our contract drilling segment experiencing an increase in the average number of rigs operating. Additionally, our pressure pumping segment experienced an increase in large multi-stage fracturing jobs in 2010 compared to 2009. This increase includes the fourth quarter contribution of a pressure pumping business we acquired on October 1, 2010, which significantly expanded our pressure pumping operations into new markets in the fourth quarter of 2010.

Our revenues, profitability and cash flows are highly dependent upon prevailing prices for natural gas and 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. After reaching a peak in June 2008, there was a significant decline in oil and natural gas prices and a substantial deterioration in the global economic environment. As part of this deterioration, there was substantial uncertainty in the capital markets and access to financing was reduced. Due to these conditions, our customers reduced or curtailed their drilling programs, which resulted in a decrease in demand for our services, as evidenced by the decline in our monthly average number of rigs operating from a high of 283 in October 2008 to a low of 60 in June 2009. Our monthly average number of rigs operating has subsequently increased from the mid-year low in 2009 to 196 in December 2010. The decline in commodity prices and deterioration in the global economy resulted in certain of our customers experiencing an inability to pay suppliers, including us. 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. Please see "Risk Factors" in Item 1A of this Report.

We believe that our liquidity as of December 31, 2010, which includes approximately $241 million in working capital and approximately $359 million available under our $400 million revolving credit facility, together with cash expected to be generated from operations, should provide us with sufficient ability to fund our current plans to build new equipment, make improvements to our existing equipment and pay cash dividends. If we pursue opportunities for growth that require capital, we believe we would be able to satisfy these needs through a combination of working capital, cash flows from operating activities borrowing capacity under our revolving credit facility or additional debt or equity financing. However, there can be no assurance that such capital will be available on reasonable terms, if at all.

Commitments and Contingencies — As of December 31, 2010, we maintained letters of credit in the aggregate amount of $41.2 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 annually at various times during the year and are typically renewed. As of December 31, 2010, no amounts had been drawn under the letters of credit.

As of December 31, 2010, we had commitments to purchase approximately $267 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, Colorado, Utah, Wyoming, Montana, North Dakota, Pennsylvania, West Virginia and western Canada. For the years ended December 31, 2010, 2009 and 2008, revenue earned in Canada was $65.7 million, $45.4 million and $88.5 million, respectively. Additionally, we had long-lived assets located in Canada of $70.7 million and $69.2 million as of December 31, 2010 and 2009, respectively. As of December 31, 2010, we had 356 marketable land-based drilling rigs. We provide pressure pumping services to oil and natural gas operators primarily in Texas and the Appalachian Basin. Pressure pumping services are primarily well stimulation and cementing for completion of new wells and remedial work on existing 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 whenever 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 continue to fluctuate. Based on management's expectations of future trends, we estimate future cash flows over the life of the respective assets in our assessment of impairment. These estimates of cash flows are based on historical cyclical trends in the industry as well as management's expectations regarding the continuation of these trends in the future. Provisions for asset impairment are charged 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.

On a periodic basis, we evaluate our fleet of drilling rigs for marketability. In connection with our long term planning process, we evaluated our then-current fleet of marketable drilling rigs in 2010, 2009 and 2008 and identified four, 23 and 22 rigs, respectively, that we determined would no longer be marketed as rigs. The components comprising these rigs were evaluated, and those components with continuing utility to our other marketed rigs were transferred to other rigs or to our yards to be used as spare equipment. The remaining components of these rigs were impaired and the associated net book value of $4.2 million in 2010, $10.5 million in 2009 and $10.4 million in 2008 was expensed in our consolidated statements of operations as an impairment charge.

In late 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 segment. With respect to these long-lived assets, 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 in 2008. Due to a continued decrease in the operating levels in our contract drilling segment through the first three quarters of 2009, we again deemed it necessary to perform an impairment assessment of long-lived assets in our contract drilling segment in 2009. Based on the estimated undiscounted cash flows associated with the assets, we determined that no impairment was indicated in 2009. In light of the recent favorable trends in rig utilization and revenue per operating day experienced by us and our peers, we concluded that no triggering event had occurred in 2010 with respect to our contract drilling segment. We also concluded that no triggering event had occurred with respect to our pressure pumping segment in 2010, 2009 or 2008. Impairment considerations related to our oil and natural gas segment are discussed below.

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. We review wells-in-progress quarterly to determine whether sufficient progress is being made in assessing the reserves and economic viability of the respective projects. If no progress has been made in assessing the reserves and economic viability of a project after one year following the completion of drilling, we consider the well costs 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 for each respective field.

We review our proved oil and natural gas properties for impairment whenever 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 commodity prices over the lives of the respective fields. These cash flow estimates are 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 net book value and discounted cash flow. The discounted cash flow estimates used in measuring impairment are based on our expectations of future commodity prices over the life of the respective field. We review unproved oil and natural gas properties quarterly to assess potential impairment. Our impairment assessment is made on a lease-by-lease basis and considers factors such as our intent to drill, lease terms and abandonment of an area. If an unproved property is determined to be impaired, the related property costs are expensed. Impairment expense related to proved and unproved oil and natural gas properties totaled approximately $792,000, $3.7 million and $4.4 million for the years ended December 31, 2010, 2009 and 2008, respectively, and is included in depreciation, depletion and impairment in the accompanying consolidated statements of operations.

Goodwill — Goodwill is considered to have an indefinite useful economic life and is not amortized. We assess impairment of our goodwill annually as of December 31, or on an interim basis if events or circumstances indicate that the fair value of goodwill may have 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.

In connection with our annual impairment assessment of goodwill, we compare the fair value of the reporting unit with its 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 unallocated 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 goodwill recorded in 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 average 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, we applied key assumptions, including 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 in 2008, we concluded that no impairment was indicated in our contract drilling reporting unit as the estimated fair value of that reporting unit exceeded its carrying value. However, an impairment was indicated in our drilling and completion fluids reporting unit as the estimated fair value of that reporting unit was less than its carrying value. 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 then performed the second step of the analysis of our drilling and completion fluids reporting unit, which included 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 approximately $10.0 million in our December 31, 2008 statement of operations. We exited the drilling and completion fluids business on January 20, 2010, and the 2008 impairment charge is included in our loss from discontinued operations in our statement of operations for the year ended December 31, 2008.

We performed our annual goodwill impairment assessment as of December 31, 2009 related to the $86.2 million in goodwill recorded in our contract drilling reporting unit. 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 the reporting unit. In developing this fair value estimate, we applied key assumptions, including an assumed discount rate of 15.42% and an assumed long-term growth rate of 3.50%. Based on the results of the first step of the impairment test in 2009, we concluded that no impairment was indicated in our contract drilling reporting unit as the estimated fair value of that reporting unit exceeded its carrying value.

We performed our annual goodwill impairment assessment as of December 31, 2010. In completing the first step of our analysis, we estimated our enterprise value based on our market capitalization as determined by reference to the closing price of our common stock during the fifteen days before and after year end. We allocated the enterprise value to our reporting units and determined that the fair values of our reporting units were in excess of their carrying value. As a result, we concluded that no impairment of goodwill was indicated as of December 31, 2010.

During the fourth quarter of 2010, we recorded goodwill in our pressure pumping reporting unit in connection with our acquisition of a pressure pumping business. The goodwill associated with this acquisition was estimated to be $67.6 million.

In the event that market conditions weaken, we may be required to record an impairment of goodwill in our contract drilling or pressure pumping reporting units in the future, and such impairment could 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 the 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 as revenue reimbursements received from third parties for out-of-pocket expenses and account for those out-of-pocket expenses as direct costs. Except for two wells drilled under footage contacts in 2009, all of the wells we drilled in 2010, 2009 and 2008 were drilled under daywork contracts.

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,
- fair values of assets acquired and liabilities assumed in acquisitions,
- goodwill and long-lived asset impairments, and
- reserves for self-insured levels of insurance coverage.

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, 2010, we had working capital of $241 million, including cash and cash equivalents of $27.6 million. During 2010, our sources of cash flow included:

- $526 million from operating activities,
- $400 million in proceeds from long term debt,
- $42.6 million in proceeds from the disposal of our drilling and completion fluids business, and
- $29.4 million in proceeds from the disposal of property and equipment.

During 2010, we used $238 million to acquire pressure pumping and electric wireline businesses, $30.8 million to pay dividends on our common stock, $10.8 million to pay debt issuance costs, $1.9 million to repurchase shares of our common stock and $738 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 segment, 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, 2010 as follows:

	Per Share	Total (In thousands)
Paid on March 30, 2010	$0.05	$ 7,677
Paid on June 30, 2010	0.05	7,706
Paid on September 30, 2010	0.05	7,704
Paid on December 30, 2010	0.05	7,709
Total cash dividends	$0.20	$30,796

On February 2, 2011, 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 30, 2011 to holders of record as of March 15, 2011. 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, authorizing purchases of up to $250 million of our common stock in open market or privately negotiated transactions. During the year ended December 31, 2010, we purchased 8,743 shares of our common stock under this program at a cost of approximately $123,000. As of December 31, 2010, we are authorized to purchase approximately $113 million of our outstanding common stock under this program.

On August 19, 2010, we entered into a Credit Agreement (the "2010 Credit Agreement"). The 2010 Credit Agreement is a committed senior unsecured credit facility that includes a revolving credit facility and a term loan facility. The 2010 Credit Agreement replaced a previous unsecured revolving credit facility.

The revolving credit facility permits aggregate borrowings of up to $400 million and contains a letter of credit facility that is limited to $150 million and a swing line facility that is limited to $40 million. Subject to customary conditions, we may request that the lenders' aggregate commitments with respect to the revolving credit facility be increased by up to $100 million, not to exceed total commitments of $500 million. The maturity date for the revolving credit facility is August 19, 2013.

The term loan facility provided for a loan of $100 million which was funded on August 19, 2010. The term loan facility is payable in quarterly principal installments commencing November 19, 2010, and the installment amounts vary from 1.25% of the original principal amount for each of the first four quarterly installments, 2.50% of the original principal amount for each of the subsequent eight quarterly installments, 5.00% of the original principal amount for the next subsequent three quarterly installments, and the remainder due at maturity. The maturity date for the term loan facility is August 19, 2014.

Loans under the 2010 Credit Agreement bear interest by reference, at our election, to the LIBOR rate or base rate. The applicable margin on LIBOR rate loans varies from 2.75% to 3.75% and the applicable margin on base rate loans varies from 1.75% to 2.75%, in each case determined based upon our debt to capitalization ratio. As of December 31, 2010, the applicable margin on LIBOR rate loans was 2.75% and the applicable margin on base rate loans was 1.75%. A letter of credit fee is payable by us equal to the applicable margin for LIBOR rate loans times the daily amount available to be drawn under outstanding letters of credit. The commitment fee payable to the lenders for the unused portion of the revolving credit facility varies from 0.50% to 0.75% based upon our debt to capitalization ratio and was 0.50% as of December 31, 2010.

The 2010 Credit Agreement contains customary representations, warranties, indemnities and affirmative and negative covenants. The 2010 Credit Agreement also requires compliance with two financial covenants. We must not permit our debt to capitalization ratio to exceed 45% at any time. The 2010 Credit Agreement generally defines the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. We also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 3.00 to 1.00. The 2010 Credit Agreement generally defines the interest coverage ratio as the ratio of earnings before interest, taxes, depreciation and amortization ("EBITDA") of the four prior fiscal quarters to interest charges for the same period. We were in compliance with these financial covenants as of December 31,

2010. We do not expect that the restrictions and covenants will impair our ability to operate or react to opportunities that might arise.

As of December 31, 2010, we had $98.8 million principal amount outstanding under the term loan facility at an interest rate of 3.125% and no borrowings outstanding under the revolving credit facility. We had $41.2 million in letters of credit outstanding at December 31, 2010, and as a result, we had available borrowing capacity of approximately $359 million at that date.

On October 5, 2010, we completed the issuance and sale of $300 million in aggregate principal amount of our 4.97% Series A Senior Notes due October 5, 2020 (the "Notes") in a private placement. A portion of the proceeds from the Notes was used to repay a $200 million borrowing on our revolving credit facility, which had been drawn to fund a portion of a business acquisition that closed on October 1, 2010.

The Notes bear interest at a rate of 4.97% per annum and were priced at 100% of the principal amount of the Notes. We will pay interest on the Notes on April 5 and October 5 of each year commencing on April 5, 2011. The Notes will mature on October 5, 2020. The Notes are prepayable at our option, in whole or in part, provided that in the case of a partial prepayment, prepayment must be in an amount not less than 5% of the aggregate principal amount of the Notes then outstanding, at any time and from time to time at 100% of the principal amount prepaid, plus accrued and unpaid interest to the prepayment date, plus a "make-whole" premium as specified in the note purchase agreement. We must offer to prepay the Notes upon the occurrence of any change of control. In addition, we must offer to prepay the Notes upon the occurrence of certain asset dispositions if the proceeds therefrom are not timely reinvested in productive assets. If any offer to prepay is accepted, the purchase price of each prepaid Note is 100% of the principal amount thereof, plus accrued and unpaid interest thereon to the prepayment date.

The note purchase agreement requires compliance with two financial covenants. We must not permit our debt to capitalization ratio to exceed 50% at any time. The note purchase agreement generally defines the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. We also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 2.50 to 1.00. The note purchase agreement generally defines the interest coverage ratio as the ratio for the four prior quarters of EBITDA to interest charges for the same period. We were in compliance with these financial covenants as of December 31, 2010. We do not expect that the restrictions and covenants will impair our ability to operate or react to opportunities that might arise.

Events of default under the note purchase agreement include failure to pay principal or interest when due, failure to comply with the financial and operational covenants, a cross default event, a judgment in excess of a threshold event, the guaranty agreement ceasing to be enforceable, the occurrence of certain ERISA events, a change of control event and bankruptcy and other insolvency events. If an event of default occurs and is continuing, then holders of a majority in principal amount of the Notes have the right to declare all the notes then-outstanding to be immediately due and payable. In addition, if we default in payments on any Note, then until such defaults are cured, the holder thereof may declare all the Notes held by it to be immediately due and payable.

We believe that our current level of cash, short-term investments and borrowing capacity available under our revolving credit facility, together with cash expected to be generated from our operating activities, should be sufficient to fund our current plans to build new equipment, make improvements to our existing equipment and pay cash dividends.

From time to time, opportunities to expand our business, including acquisitions and the building of new equipment, are evaluated. The timing, size or success of any acquisition and the associated capital commitments are unpredictable. If we pursue opportunities for growth that require capital, we believe we would be able to satisfy these needs through a combination of working capital, cash generated from operations, borrowing capacity under our revolving credit facility or additional debt or equity financing. However, there can be no assurance that such 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, 2010 (dollars in thousands):

	Payments due by period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Borrowings under revolving credit facility(1)	$ —	$ —	$ —	$ —	$ —
Borrowings under term loan(2)	98,750	6,250	22,500	70,000	—
Interest on term loan(3)	9,371	3,097	5,267	1,007	—
Series A Senior Notes(4)	300,000	—	—	—	300,000
Interest on Series A Senior Notes(5)	145,546	14,910	29,820	29,820	70,996
Commitments to purchase equipment(6)	266,567	266,567	—	—	—
	$820,234	$290,824	$57,587	$100,827	$370,996

(1) No borrowings were outstanding on our revolving credit facility as of December 31, 2010. Any borrowings that are drawn on our revolving credit facility would be due at maturity August 19, 2013.

(2) Represents repayments of borrowing under the term loan portion of the 2010 Credit Agreement. The term loan matures on August 19, 2014.

(3) Interest to be paid on term loan using 3.25% rate in effect as of December 31, 2010.

(4) Principal repayment of the Series A Senior Notes is required at maturity on October 5, 2020.

(5) Interest to be paid on the Series A Senior Notes using 4.97% coupon rate.

(6) Represents commitments to purchase major equipment to be delivered in 2011 based on expected delivery dates.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements at December 31, 2010.

Results of Operations

Comparison of the years ended December 31, 2010 and 2009

The following tables summarize operations by business segment for the years ended December 31, 2010 and 2009:

Contract Drilling	Year Ended December 31, 2010	2009	% Change
	(Dollars in thousands)		
Revenues	$1,081,898	$599,287	80.5%
Direct operating costs	$ 655,678	$357,742	83.3%
Selling, general and administrative	$ 5,279	$ 4,340	21.6%
Depreciation and impairment	$ 280,458	$248,424	12.9%
Operating income (loss)	$ 140,483	$ (11,219)	N/M
Operating days	61,244	33,394	83.4%
Average revenue per operating day	$ 17.67	$ 17.95	(1.6)%
Average direct operating costs per operating day	$ 10.71	$ 10.71	0.0%
Average rigs operating	168	91	84.6%
Capital expenditures	$ 655,550	$395,376	65.8%

The demand for our contract drilling services is impacted by the market price of natural gas and 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 and oil for each of the fiscal quarters and full year in 2010 and 2009 follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year
2009:					
Average natural gas price per Mcf(1)	$ 4.71	$ 3.82	$ 3.26	$ 4.46	$ 4.06
Average oil price per Bbl(2)	$42.91	$59.44	$68.20	$76.06	$61.65
2010:					
Average natural gas price per Mcf(1)	$ 5.30	$ 4.45	$ 4.41	$ 3.91	$ 4.52
Average oil price per Bbl(2)	$78.64	$77.79	$76.05	$85.10	$79.40

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

(2) The average oil price represents the average monthly Cushing, OK WTI spot price as reported by the United States Energy Information Administration.

Revenues and direct operating costs increased in 2010 compared to 2009 as a result of an increase in the number of operating days. The increase in operating days was due to increased demand largely caused by higher prices for natural gas and oil. Our average number of rigs operating during 2009 included an average of approximately six rigs operating under term contracts that earned standby revenues of $22.3 million. Rigs on standby earn a discounted dayrate as they do not have crews and have lower costs. We had no significant standby revenue associated with rigs operating under term contracts in 2010. We recognized approximately $8.0 million of revenues during 2009 from the early termination of term contracts. We had no such revenue from the early termination of term contracts in 2010. Selling, general and administrative expenses increased in 2010 primarily as a result of increased personnel costs to support increased activity levels. Significant capital expenditures were incurred in 2010 and 2009 to build new drilling rigs, to modify and upgrade our drilling rigs and to acquire additional related equipment such as top drives, drill pipe, drill collars, engines, fluid circulating systems, rig hoisting systems and safety enhancement equipment. Depreciation expense increased as a result of capital expenditures. Depreciation and impairment expense includes approximately $4.2 million in 2010 and approximately $10.5 million in 2009 of impairment charges related to drilling equipment on drilling rigs that were removed from our marketable fleet. We removed four rigs from our marketable fleet in 2010 and removed 23 rigs from our marketable fleet in 2009.

	Year Ended December 31,		
Pressure Pumping	2010	2009	% Change
	(Dollars in thousands)		
Revenues	$350,608	$161,441	117.2%
Direct operating costs	$235,100	$124,100	89.4%
Selling, general and administrative	$ 12,590	$ 8,735	44.1%
Depreciation and amortization	$ 40,724	$ 27,589	47.6%
Operating income	$ 62,194	$ 1,017	N/M
Fracturing jobs	1,527	1,579	(3.3)%
Other jobs	6,047	5,399	12.0%
Total jobs	7,574	6,978	8.5%
Average revenue per fracturing job	$ 180.21	$ 70.88	154.2%
Average revenue per other job	$ 12.47	$ 9.17	36.0%
Average revenue per total job	$ 46.29	$ 23.14	100.0%
Average direct operating costs per total job	$ 31.04	$ 17.78	74.6%
Capital expenditures	$ 51,064	$ 43,144	18.4%

Revenues and direct operating costs increased primarily as a result of the increase in the number of larger multi-stage fracturing jobs, which was driven by higher demand for services associated with unconventional reservoirs. Also contributing to these increases was our acquisition of a pressure pumping business on October 1, 2010 which significantly expanded the size of our fleet of pressure pumping equipment and the markets in which we provide pressure pumping services. This acquisition was accounted for as a business combination and the results of operations of the acquired business are included in our pressure pumping segment results from the date of acquisition. The acquired business contributed revenue of $84.7 million and operating income of $22.8 million to our operating results during the year ended December 31, 2010.

Our customers have increased their activities in the development of unconventional reservoirs resulting in an increase in larger multi-stage fracturing jobs associated therewith. As a result, we have experienced an increase in the number of these larger multi-stage fracturing jobs as a proportion of the total fracturing jobs we performed. Average revenue per other job increased as a result of increased pricing for the services provided and a change in job mix. Selling, general and administrative expenses in 2010 include $1.5 million associated with the acquired business. The remaining increase in selling, general and administrative expenses is due to additional costs necessary to support increased business activity in 2010. Significant capital expenditures have been incurred in recent years to add capacity in our pressure pumping segment. Depreciation and amortization expense in 2010 includes $1.0 million in amortization of intangible assets and $4.7 million in depreciation of property and equipment associated with the acquired business. The remaining increase in depreciation in 2010 compared to 2009 is a result of our recent capital expenditures.

Oil and Natural Gas Production and Exploration	Year Ended December 31,		
	2010	2009	% Change
	(Dollars in thousands, except commodity prices)		
Revenues	$30,425	$21,218	43.4%
Direct operating costs	$ 7,020	$ 7,341	(4.4)%
Depreciation, depletion and impairment	$10,950	$12,927	(15.3)%
Operating income	$12,455	$ 950	N/M
Capital expenditures	$23,067	$ 7,341	214.2%
Average net daily oil production (Bbls)	877	761	15.2%
Average net daily gas production (Mcf)	2,788	3,225	(13.6)%
Average oil sales price (per Bbl)	$ 77.26	$ 58.09	33.0%
Average gas sales price (per Mcf)	$ 5.60	$ 4.32	29.6%

Revenues increased due to higher average sales prices of oil and natural gas and increased oil production partially offset by a decline in natural gas production. Average net daily oil production increased primarily due to the addition of new wells. Average net daily natural gas production decreased primarily due to production declines on existing wells. Depreciation, depletion and impairment expense in 2010 includes approximately $792,000 of oil and natural gas property impairments compared to approximately $3.7 million of oil and natural gas property impairments in 2009. Depletion expense increased approximately $915,000 in 2010 compared to 2009. Capital expenditures increased in 2010 as a result of greater drilling activity and increased costs per well.

Corporate and Other	Year Ended December 31,		
	2010	2009	% Change
	(Dollars in thousands)		
Selling, general and administrative	$ 35,173	$30,860	14.0%
Depreciation	$ 1,361	$ 907	50.1%
Provision for bad debts	$ (2,000)	$ 3,810	N/M
Net (gain) loss on asset disposals	$(22,812)	$ 3,385	N/M
Acquisition-related expenses	$ 2,485	$ —	N/M
Interest income	$ 1,674	$ 381	339.4%
Interest expense	$ 12,772	$ 4,148	207.9%
Other income	$ 927	$ 426	117.6%
Capital expenditures	$ 8,409	$ 6,785	23.9%

Selling, general and administrative expense increased in 2010 primarily as a result of increased personnel costs. The provision for bad debts in 2009 resulted from an increase in our reserve on specific account balances based on the deteriorating economic and credit environment at the time. The negative provision for bad debts in 2010 is the result of reductions in our reserve for specific accounts due to improved industry conditions. Gains and losses on the disposal of assets are treated as part of our corporate activities because such transactions relate to corporate strategy decisions of our executive management group. The gain on asset disposals in 2010 includes a gain of $20.1 million related to the sale of certain rights to explore and develop zones deeper than depths that we generally target for certain of the oil and natural gas properties in which we have working interests. Losses on asset disposals in 2009 were primarily related to the disposal of contract drilling equipment. Acquisition-related expenses in 2010 were incurred in connection with the acquisition of pressure pumping and electric wireline businesses during the fourth quarter of 2010. These expenses included certain legal and other professional fees directly related to the transaction, fees incurred in connection with the title transfers of the acquired equipment and transition costs related to information technology. Interest income increased due to the collection of interest on a customer account as well as interest received on prior overpayments of sales taxes in certain jurisdictions. Interest expense in 2010 includes $3.3 million due to the recognition of remaining deferred financing costs associated with a revolving credit facility that was replaced in August 2010, and $1.3 million due to the recognition of financing costs associated with a bridge facility that expired unused on September 30, 2010. The remainder of the 2010 increase relates to interest charges and the amortization of debt issuance costs associated with the $100 million term loan entered into in August 2010 and the $300 million Senior Notes issued in October 2010. Capital expenditures increased in 2010 due to the ongoing implementation of a new enterprise resource planning system.

Discontinued Operations:	Year Ended December 31, 2010	2009	% Change
	(Dollars in thousands)		
Electric wireline revenue	$5,712	$ —	N/M
Electric wireline direct operating costs	$4,962	$ —	N/M
Drilling and completion fluids revenue	$3,737	$79,786	(95.3)%
Drilling and completion fluids direct operating costs	$3,307	$74,180	(95.5)%
Selling, general and administrative	$ 358	$ 7,192	(95.0)%
Depreciation	$ 166	$ 2,287	(92.7)%
Impairment of assets held for sale	$2,155	$ 1,900	13.4%
Net gain on asset disposals/retirements	$ —	$ (125)	(100.0%
Other operating expense	$ —	$ 890	(100.0)%
Income tax expense (benefit)	$ (543)	$ (2,208)	(75.4)%
Loss from discontinued operations, net of income taxes	$ (956)	$ (4,330)	(77.9)%

On January 27, 2011, we sold our electric wireline business, which had been acquired by us on October 1, 2010. The results of operations of this business have been classified as a discontinued operation and the assets held for sale at December 31, 2010 are presented at net realizable value in the consolidated balance sheet. On January 20, 2010, we sold our drilling and completion fluids services business which had previously been presented as one of our reportable operating segments. Due to our exit from this business, we have classified our drilling and completion fluids operating segment as a discontinued operation. Impairment of assets held for sale in 2010 and 2009 reflects the transaction-related costs recorded to reduce the carrying value of the assets sold to their net realizable value at December 31, 2010, and 2009.

Comparison of the years ended December 31, 2009 and 2008

The following tables summarize operations by business segment for the years ended December 31, 2009 and 2008:

Contract Drilling	Year Ended December 31, 2009	2008	% Change
	(Dollars in thousands)		
Revenues	$599,287	$1,804,026	(66.8)%
Direct operating costs	$357,742	$1,038,327	(65.5)%
Selling, general and administrative	$ 4,340	$ 5,363	(19.1)%
Depreciation and impairment	$248,424	$ 239,700	3.6%
Operating income (loss)	$(11,219)	$ 520,636	N/M
Operating days	33,394	93,068	(64.1)%
Average revenue per operating day	$ 17.95	$ 19.38	(7.4)%
Average direct operating costs per operating day	$ 10.71	$ 11.16	(4.0)%
Average rigs operating	91	254	(64.2)%
Capital expenditures	$395,376	$ 360,645	9.6%

The demand for our contract drilling services is impacted by the market price of natural gas and 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 and oil for each of the fiscal quarters and full year in 2009 and 2008 follow:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year
2008:					
Average natural gas price per Mcf(1)	$ 8.92	$ 11.74	$ 9.28	$ 6.60	$ 9.13
Average oil price per Bbl(2)	$97.94	$123.95	$118.05	$58.35	$99.57
2009:					
Average natural gas price per Mcf(1)	$ 4.71	$ 3.82	$ 3.26	$ 4.46	$ 4.06
Average oil price per Bbl(2)	$42.91	$ 59.44	$ 68.20	$76.06	$61.65

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

(2) The average oil price represents the average monthly Cushing, OK WTI spot price as reported by the United States Energy Information Administration.

Revenues and direct operating costs decreased in 2009 compared to 2008 primarily as a result of a decrease in the number of operating days. The decrease in operating days was due to decreased demand largely caused by lower commodity prices for natural gas and oil. Our average number of rigs operating during 2009 included an average of approximately six rigs operating under term contracts that earned standby revenues of $22.3 million. This represented an increase from an average of approximately one rig operating under a term contract that earned standby revenues of $4.7 million in 2008. Rigs on standby earn a discounted dayrate as they do not have crews and have lower costs. We recognized approximately $8.0 million of revenues during 2009 from the early termination of drilling contracts compared to approximately $1.3 million in 2008. Average revenue per operating day decreased in 2009 primarily due to decreases in dayrates for rigs that were operating in the spot market and the expiration of term contracts that were entered into at higher rates. Average direct operating costs per operating day decreased in 2009 primarily due to decreases in labor and repair costs. Significant capital expenditures were incurred in 2009 and 2008 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. Depreciation expense increased as a result of those capital expenditures. Depreciation and impairment expense includes approximately $10.5 million in 2009 and approximately $10.4 million in 2008 of impairment charges related to drilling equipment on drilling rigs that were removed from our marketable fleet. We removed 23 rigs from our marketable fleet in 2009 and removed 22 rigs from our marketable fleet in 2008.

Pressure Pumping	Year Ended December 31, 2009	2008	% Change
	(Dollars in thousands)		
Revenues	$161,441	$217,494	(25.8)%
Direct operating costs	$124,100	$147,377	(15.8)%
Selling, general and administrative	$ 8,735	$ 8,498	2.8%
Depreciation	$ 27,589	$ 19,600	40.8%
Operating income	$ 1,017	$ 42,019	(97.6)%
Fracturing jobs	1,579	2,898	(45.5)%
Other jobs	5,399	9,162	(41.1)%
Total jobs	6,978	12,060	(42.1)%
Average revenue per fracturing job	$ 70.88	$ 49.62	42.8%
Average revenue per other job	$ 9.17	$ 8.04	14.1%
Average revenue per total job	$ 23.14	$ 18.03	28.3%
Average direct operating costs per total job	$ 17.78	$ 12.22	45.5%
Capital expenditures	$ 43,144	$ 61,289	(29.6)%

Our customers have increased their activities in the development of unconventional reservoirs resulting in an increase in larger multi-stage fracturing jobs associated therewith. As a result, we have experienced an increase in the number of these larger multi-stage fracturing jobs as a proportion of the total fracturing jobs we performed. In 2009 we experienced a decrease in smaller traditional pressure pumping jobs due to depressed commodity prices, which contributed to the overall decrease in revenue and direct operating costs. In anticipation of increased activity associated with the unconventional reservoirs in the Appalachian Basin, we added facilities, equipment and personnel. Delays in the development of these reservoirs and lower commodity prices caused a slower increase in customer activity than we had expected, negatively impacting the profitability of this business. Significant capital expenditures have been incurred in recent years to add capacity. Depreciation expense increased as a result of our recent capital expenditures.

Oil and Natural Gas Production and Exploration	Year Ended December 31, 2009	2008	% Change
	(Dollars in thousands, except commodity prices)		
Revenues	$21,218	$42,360	(49.9)%
Direct operating costs	$ 7,341	$12,793	(42.6)%
Depreciation, depletion and impairment	$12,927	$15,856	(18.5)%
Operating income	$ 950	$13,711	(93.1)%
Capital expenditures	$ 7,341	$22,981	(68.1)%
Average net daily oil production (Bbls)	761	801	(5.0)%
Average net daily gas production (Mcf)	3,225	3,755	(14.1)%
Average oil sales price (per Bbl)	$ 58.09	$ 98.70	(41.1)%
Average gas sales price (per Mcf)	$ 4.32	$ 9.77	(55.8)%

Revenues decreased due to lower average sales prices and lower average net daily production of oil and natural gas. Average net daily oil and natural gas production decreased primarily due to production declines on existing wells. Direct operating costs decreased primarily due to decreases in seismic expenses as well as decreased production taxes and other production costs. Depreciation, depletion and impairment expense in 2009 includes approximately $3.7 million of oil and natural gas property impairments compared to approximately $4.4 million of oil and natural gas property impairments in 2008. Depletion expense decreased approximately $2.3 million primarily due to lower production and the impact of decreases in the carrying value of properties resulting from previous impairment charges. Capital expenditures decreased in 2009 as a result of declines in commodity prices.

Corporate and Other	Year Ended December 31, 2009	2008	% Change
	(Dollars in thousands)		
Selling, general and administrative	$30,860	$29,412	4.9%
Depreciation	$ 907	$ 834	8.8%
Provision for bad debts	$ 3,810	$ 4,350	(12.4)%
Net (gain) loss on asset disposals	$ 3,385	$ (4,163)	N/M
Interest income	$ 381	$ 1,553	(75.5)%
Interest expense	$ 4,148	$ 630	558.4%
Other income	$ 426	$ 502	(15.1)%
Capital expenditures	$ 6,785	$ 511	N/M

Selling, general and administrative expense increased in 2009 primarily as a result of increased professional fees. The provision for bad debts resulted from an increase in our reserve on specific account balances based on the deteriorating economic and credit environment in 2008 and 2009. Gains and losses on the disposal of assets are treated as part of our corporate activities because such transactions relate to corporate strategy decisions of our executive management group. Losses on asset disposals in 2009 were primarily related to the disposal of contract drilling equipment. Gains on asset disposals in 2008 were primarily related to gains on the sale of contract drilling equipment and the sale of oil and natural gas properties. Interest expense increased in 2009 due to the amortization of debt issuance costs and increased fees associated with outstanding letters of credit and the unused portion of the revolving credit facility that was put into place in 2009. Capital expenditures increased in 2009 due to the purchase and ongoing implementation of a new enterprise resource planning system.

Discontinued Operations:	Year Ended December 31, 2009	2008	% Change
	(Dollars in thousands)		
Drilling and completion fluids revenue	$79,786	$145,246	(45.1)%
Drilling and completion fluids direct operating costs	$74,180	$126,900	(41.5)%
Selling, general and administrative	$ 7,192	$ 10,110	(28.9)%
Depreciation	$ 2,287	$ 2,830	(19.2)%
Goodwill impairment	$ —	$ 9,964	(100.0)%
Impairment of assets held for sale	$ 1,900	$ —	N/M
Net gain on asset disposals/retirements	$ (125)	$ (155)	(19.4)%
Other operating expense	$ 890	$ —	N/M
Net interest expense	$ —	$ 7	(100.0)%
Income tax expense (benefit)	$ (2,208)	$ 2,389	N/M
Loss from discontinued operations, net of income taxes	$ (4,330)	$ (6,799)	36.3%

On January 20, 2010, we exited our drilling and completion fluids services business, which had previously been presented as one of our reportable operating segments. Due to our exit from this business, we have classified our drilling and completion fluids operating segment as a discontinued operation. Accordingly, the assets and liabilities of this business, along with its results of operations, were reclassified for all periods presented. Drilling and completion fluids revenue and direct operating costs decreased in 2009 due to decreased sales volume both on land and offshore in the Gulf of Mexico. Drilling and completion fluids selling, general and administrative expenses decreased in 2009 primarily due to a decrease in compensation costs for sales and support personnel due to headcount reductions. Goodwill impairment was recognized in the drilling and completion fluids reporting unit in 2008 as a result of our annual impairment testing which indicated that the fair value of goodwill in that reporting unit was zero. Impairment of assets held for sale in 2009 of $1.9 million represents the transaction-related costs recorded to reduce the carrying value of the assets sold to their net realizable value at December 31, 2009. In 2008, income tax expense was recognized despite a pre-tax loss in the drilling and completion fluids business due to the fact that the goodwill impairment recorded in that year was not deductible for tax purposes.

Income Taxes

	Year Ended December 31,		
	2010	2009	2008
	(Dollars in thousands)		
Income (loss) from continuing operations before income tax	$190,754	$(51,555)	$547,358
Income tax expense (benefit)	72,856	(17,595)	193,490
Effective tax rate	38.2%	34.1%	35.3%

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

	2010	2009	2008
Statutory tax rate	35.0%	35.0%	35.0%
State income taxes	1.1	4.7	1.7
Permanent differences	2.3	(5.7)	(1.2)
Other, net	(0.2)	0.1	(0.2)
Effective tax rate	38.2%	34.1%	35.3%

For 2008, the permanent difference indicated above was largely attributable to our Domestic Production Activities Deduction. 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) and allows a deduction of 6% in both 2008 and 2009 and 9% in 2010 and thereafter on the lesser of qualified production activities income or taxable income. The permanent differences for 2010 and 2009 reflect the recapture of a portion of this deduction due to the planned carryback of the 2010 net operating loss to prior years and the carryback of the 2009 net operating loss to prior years. This recapture resulted in a negative effective rate impact in 2009 due to the Company having a loss before income taxes in that year.

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 recognized deferred tax expense of approximately $147 million in 2010, $101 million in 2009 and $65.4 million in 2008.

On January 1, 2010, we converted our Canadian operations from a Canadian branch to a controlled foreign corporation for Federal income tax purposes. Because the statutory tax rates in Canada are lower than those in the United States, this transaction triggered a $5.1 million reduction in deferred tax liabilities, which is being amortized as a reduction to deferred income tax expense over the weighted average remaining useful life of the Canadian assets.

As a result of the above conversion, our Canadian assets are no longer subject to United States taxation, provided that the related unremitted earnings are permanently reinvested in Canada. Effective January 1, 2010, we have elected to permanently reinvest these unremitted earnings in Canada, and intend to do so for the foreseeable future. As a result, no deferred United States Federal or state income taxes have been provided on such unremitted foreign earnings, which totaled approximately $6.3 million as of December 31, 2010.

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

Our revenue, profitability, financial condition and rate of growth are substantially dependent upon prevailing prices for natural gas and 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 (monthly average Henry Hub price as reported by the United States Energy Information Administration) peaked in June at $13.06 per Mcf before rapidly declining to an average of $5.99 per Mcf in December. In 2009, the monthly average market price of natural gas declined further to a low of $3.06 per Mcf in September. This decline in the market price of natural gas resulted in our customers significantly reducing their drilling activities beginning in the fourth quarter of 2008, and drilling activities remained low throughout 2009 before recovering somewhat in 2010. Construction of new land drilling rigs in the United States during the last ten years has significantly contributed to excess capacity. As a result of these factors, our average number of rigs operating has declined significantly from historic highs. 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. Low market prices for natural gas and oil would likely result in lower demand for our drilling rigs and pressure pumping services and adversely affect our operating results, financial condition and cash flows.

The North American land drilling industry has experienced downturns in demand during 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 and, at times, have incurred losses 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, 2010. We believe that inflation will not have a significant near-term impact on our financial position.

Recently Issued Accounting Standards

In June 2009, the FASB issued a new accounting standard that amends the accounting and disclosure requirements for the consolidation of variable interest entities. This new standard removes the previously existing exception from applying consolidation guidance to qualifying special-purpose entities and requires ongoing reassessments of whether an enterprise is the primary beneficiary of a variable interest entity. Prior to this new standard, generally accepted accounting principles required reconsideration of whether an enterprise is the primary beneficiary of a variable interest entity only when specific events occurred. This new standard is effective as of the beginning of each reporting entity’s first annual reporting period that begins after November 15, 2009, for interim periods within that first annual reporting period, and for interim and annual reporting periods thereafter. This new standard became effective for us on January 1, 2010. The adoption of this standard did not impact our consolidated financial statements.

In October 2009, the FASB issued a new accounting standard that addresses the accounting for multiple-deliverable revenue arrangements to enable vendors to account for deliverables separately rather than as a combined unit. This new standard addresses how to separate deliverables and how to measure and allocate arrangement consideration to one or more units of accounting. Existing accounting standards require a vendor to use objective and reliable evidence of fair value for the undelivered items or the residual method to separate deliverables in a multiple-deliverable arrangement. Under the new standard, it is expected that multiple-deliverable arrangements will be separated in more circumstances than under current requirements. The new standard establishes a hierarchy for determining the selling price of a deliverable for purposes of allocating revenue to multiple deliverables. The selling price used will be based on vendor-specific objective evidence if available, third-party evidence if vendor-specific objective evidence is not available, or estimated selling price if neither vendor-specific objective evidence nor third-party evidence is available. The new standard must be prospectively applied to all revenue arrangements entered into in fiscal years beginning on or after June 15, 2010 and became effective for us on January 1, 2011. The adoption of this standard did not have a material impact on our consolidated financial position, results of operations or cash flows.

In December 2010, the FASB issued an accounting standard update that addresses the disclosure of supplementary pro forma information for business combinations. This update clarifies that when public entities are required to disclose pro forma information for business combinations that occurred in the current reporting period, the pro forma information should be presented as if the business combination occurred as of the beginning of the previous fiscal year when comparative financial statements are presented. This update is effective prospectively 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, 2010. Early adoption is permitted. We elected to early adopt this update and this early adoption did not have an impact on our consolidated financial position, results of operations or cash flows.

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 term credit facility or our revolving credit facility. Interest is paid on the outstanding principal amount of borrowings at a floating rate based on, at our election, LIBOR or a base rate. The margin on LIBOR loans ranges from 2.75% to 3.75% and the margin on base rate loans ranges from 1.75% to 2.75%, based on our debt to capitalization ratio. At December 31, 2010, the margin on LIBOR loans was 2.75% and the margin on base rate loans was 1.75%. As of December 31, 2010, we had no borrowings outstanding under our revolving credit facility and $98.8 million outstanding under our term credit facility at an interest rate of 3.125%. The interest rate on the borrowing outstanding under our term credit facility is variable and adjusts at each interest payment date based on our election of LIBOR or the base rate. A one percent increase in the interest rate on the borrowing outstanding under our term credit facility as of December 31, 2010 would increase our annual cash interest expense by $987,500.

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 Exchange Act, as of the end of the period covered by this Report. Based on this evaluation, our CEO and CFO concluded that, as of December 31, 2010, 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, 2010, 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, 2010.

Our wholly-owned subsidiaries, Universal Pressure Pumping, Inc. ("UPP") and Universal Wireline, Inc. ("UWL"), were excluded from our evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2010. UPP and UWL were formed in 2010 for the purpose of acquiring the assets of pressure pumping and wireline businesses in a business acquisition which closed on October 1, 2010. These subsidiaries were excluded from the scope of our review due to the fact that the acquisition closed in the fourth quarter of 2010, at which time we began integrating the acquired businesses into our existing internal controls over financial reporting. The acquired businesses represented approximately 6 percent of consolidated revenues for the year ended December 31, 2010 and approximately 9 percent of consolidated total assets as of December 31, 2010.

The effectiveness of our internal control over financial reporting as of December 31, 2010 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 which is incorporated by reference into Item 8 of this Report.

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. As discussed above, we began integrating the acquired pressure pumping and wireline businesses into our existing internal control over financial reporting during the most recently completed fiscal quarter.

Item 9B. ***Other Information***

None.

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.

We have adopted a Code of Business Conduct and Ethics for Senior Financial Executives, which covers, among others, our principal executive officer, principal financial officer and principal accounting officer. The text of this code is located on our website under “Governance.” Our Internet address is www.patenergy.com. We intend to disclose any amendments to or waivers from this code on our website.

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.

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.

2.1 Asset Purchase Agreement dated July 2, 2010 by and among Patterson-UTI Energy, Inc., Portofino Acquisition Company (n/k/a Universal Pressure Pumping, Inc.), Key Energy Pressure Pumping Services, LLC, Key Electric Wireline Services, LLC and Key Energy Services, Inc. (filed July 6, 2010 as Exhibit 2.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

2.2 Letter Agreement dated September 1, 2010 by and among Patterson-UTI Energy, Inc., Universal Pressure Pumping, Inc., Universal Wireline, Inc., Key Energy Services, Inc., Key Energy Pressure Pumping Services, LLC, and Key Electric Wireline Services LLC (filed November 1, 2010 as Exhibit 2.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2010 and incorporated herein by reference).

2.3 Letter Agreement dated October 1, 2010 by and among Patterson-UTI Energy, Inc., Universal Pressure Pumping, Inc., Universal Wireline, Inc., Key Energy Services, Inc., Key Energy Pressure Pumping Services, LLC, and Key Electric Wireline Services LLC (filed November 1, 2010 as Exhibit 2.3 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2010 and incorporated herein by reference).

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 to 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 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).*

10.3 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).*

10.4 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).*

10.5 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).*

10.6 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).*

10.7 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).*

10.8 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).*

10.9 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).*

10.10 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).*

10.11 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).

10.12 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).

10.13 Third Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed April 27, 2010 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

10.14 Fourth Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed April 27, 2010 as Exhibit 10.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

10.15 Fifth Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed April 27, 2010 as Exhibit 10.3 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

10.16 Form of Cash-Settled Performance Unit Award Agreement pursuant to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan, as amended from time to time (filed February 19, 2010 as Exhibit 10.9 to the Company's Annual Report on Form 10-K for the year ended December 31, 2009 and incorporated herein by reference).*

10.17 Form of Amendment to Cash-Settled Performance Unit Award Agreement under the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed May 4, 2010 as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2010 and incorporated herein by reference).*

10.18 Form of Share-Settled Performance Unit Award Agreement under the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed August 2, 2010 as Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2010 and incorporated herein by reference).*

10.19 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, Seth D. Wexler 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).*

10.20 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).*

10.21 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of November 2, 2009, by and between Patterson-UTI Energy, Inc. and Seth D. Wexler (filed November 2, 2009 as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2009 and incorporated herein by reference).*

10.22 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).*

10.23 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).*

10.24 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).*

10.25 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).*

10.26 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).*

10.27 Credit Agreement dated August 19, 2010, among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, letter of credit issuer and lender and each of the other letter of credit issuer and lender parties thereto (filed August 19, 2010 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.28 Note Purchase Agreement dated October 5, 2010 by and among Patterson-UTI Energy, Inc. and the purchasers named therein (filed October 6, 2010 as Exhibit 10.1 to the Company's Current Report on Form 8-K 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.

101 The following materials from Patterson-UTI Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2010, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Income, (iii) the Consolidated Statements of Changes in Stockholders' Equity, (iv) the Consolidated Statements of Cash Flows, and (v) Notes to Consolidated Financial Statements, tagged as blocks of text.

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* 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 (the "Company") at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 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, 2010, 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.

As described in Management's Report on Internal Control Over Financial Reporting, management has excluded Universal Pressure Pumping, Inc. and Universal Wireline, Inc. from its assessment of internal control over financial reporting as of December 31, 2010 because they were formed in 2010 to acquire certain pressure pumping and wireline businesses in a business combination during the fourth quarter of 2010. We have also excluded Universal Pressure Pumping, Inc. and Universal Wireline, Inc. from our audit of internal control over financial reporting. As of December 31, 2010, Universal Pressure Pumping, Inc. and Universal Wireline, Inc. were wholly-owned subsidiaries whose total assets and total revenues represented 9 percent and 6 percent, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2010.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 14, 2011

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2010	December 31, 2009
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 27,612	$ 49,877
Accounts receivable, net of allowance for doubtful accounts of $5,114 and $10,911 at December 31, 2010 and 2009, respectively	337,167	164,498
Federal and state income taxes receivable	75,062	118,869
Inventory	17,215	6,941
Deferred tax assets, net	26,815	32,877
Assets held for sale	23,370	42,424
Other	50,169	40,475
Total current assets	557,410	455,961
Property and equipment, net	2,620,900	2,110,402
Goodwill and intangible assets	179,683	86,234
Deposits on equipment purchases	51,084	914
Other	13,954	8,641
Total assets	$3,423,031	$2,662,152
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 162,400	$ 83,700
Accrued expenses	147,315	108,750
Current portion of long term debt	6,250	—
Total current liabilities	315,965	192,450
Long term debt	392,500	—
Deferred tax liabilities, net	511,422	381,656
Other	15,537	6,346
Total liabilities	1,235,424	580,452
Commitments and contingencies (see Note 9)	—	—
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 181,537,568 and 180,828,773 issued and 154,193,754 and 153,610,785 outstanding at December 31, 2010 and 2009, respectively	1,815	1,808
Additional paid-in capital	796,641	781,635
Retained earnings	1,987,999	1,901,853
Accumulated other comprehensive income	21,597	14,996
Treasury stock, at cost, 27,343,814 shares and 27,217,988 shares at December 31, 2010 and 2009, respectively	(620,445)	(618,592)
Total stockholders' equity	2,187,607	2,081,700
Total liabilities and stockholders' equity	$3,423,031	$2,662,152

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2010	2009	2008
	(In thousands, except per share data)		
Operating revenues:			
Contract drilling	$1,081,898	$ 599,287	$1,804,026
Pressure pumping	350,608	161,441	217,494
Oil and natural gas	30,425	21,218	42,360
Total operating revenues	1,462,931	781,946	2,063,880
Operating costs and expenses:			
Contract drilling	655,678	357,742	1,038,327
Pressure pumping	235,100	124,100	147,377
Oil and natural gas	7,020	7,341	12,793
Depreciation, depletion, amortization and impairment	333,493	289,847	275,990
Selling, general and administrative	53,042	43,935	43,273
Net (gain) loss on asset disposals	(22,812)	3,385	(4,163)
Provision for bad debts	(2,000)	3,810	4,350
Acquisition-related expenses	2,485	—	—
Total operating costs and expenses	1,262,006	830,160	1,517,947
Operating income (loss)	200,925	(48,214)	545,933
Other income (expense):			
Interest income	1,674	381	1,553
Interest expense	(12,772)	(4,148)	(630)
Other	927	426	502
Total other income (expense)	(10,171)	(3,341)	1,425
Income (loss) from continuing operations before income taxes	190,754	(51,555)	547,358
Income tax expense (benefit):			
Current	(74,634)	(119,038)	128,098
Deferred	147,490	101,443	65,392
Total income tax expense (benefit)	72,856	(17,595)	193,490
Income (loss) from continuing operations	117,898	(33,960)	353,868
Loss from discontinued operations, net of income taxes	(956)	(4,330)	(6,799)
Net income (loss)	$ 116,942	$ (38,290)	$ 347,069
Basic income (loss) per common share:			
Income (loss) from continuing operations	$ 0.77	$ (0.22)	$ 2.29
Loss from discontinued operations, net of income taxes	$ (0.01)	$ (0.03)	$ (0.04)
Net income (loss)	$ 0.76	$ (0.25)	$ 2.25
Diluted income (loss) per common share:			
Income (loss) from continuing operations	$ 0.76	$ (0.22)	$ 2.27
Loss from discontinued operations, net of income taxes	$ (0.01)	$ (0.03)	$ (0.04)
Net income (loss)	$ 0.76	$ (0.25)	$ 2.23
Weighted average number of common shares outstanding:			
Basic	152,772	152,069	153,379
Diluted	153,276	152,069	154,358
Cash dividends per common share	$ 0.20	$ 0.20	$ 0.60

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

	Common Stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income	Treasury Stock	Total
	Number of Shares	Amount					
				(In thousands)			
Balance, December 31, 2007	177,386	$1,773	$703,581	$1,716,620	$ 20,207	$(546,151)	$1,896,030
Comprehensive income:							
Net income	—	—	—	347,069	—	—	347,069
Foreign currency translation adjustment, (net of tax of $8,368)	—	—	—	—	(14,433)	—	(14,433)
Total comprehensive income	—	—	—	347,069	(14,433)	—	332,636
Issuance of restricted stock	577	6	(6)	—	—	—	—
Forfeitures of restricted stock	(75)	(1)	1	—	—	—	—
Exercise of stock options	2,304	23	25,525	—	—	—	25,548
Stock-based compensation	—	—	20,131	—	—	—	20,131
Tax benefit related to stock-based compensation	—	—	16,280	—	—	—	16,280
Payment of cash dividends	—	—	—	(92,865)	—	—	(92,865)
Purchase of treasury stock	—	—	—	—	—	(70,818)	(70,818)
Balance, December 31, 2008	180,192	1,801	765,512	1,970,824	5,774	(616,969)	2,126,942
Comprehensive income (loss):							
Net loss	—	—	—	(38,290)	—	—	(38,290)
Foreign currency translation adjustment, (net of tax of $5,347)	—	—	—	—	9,222	—	9,222
Total comprehensive loss	—	—	—	(38,290)	9,222	—	(29,068)
Issuance of restricted stock	604	6	(6)	—	—	—	—
Vesting of restricted stock units	6	—	—	—	—	—	—
Forfeitures of restricted stock	(56)	—	—	—	—	—	—
Exercise of stock options	83	1	568	—	—	—	569
Stock-based compensation	—	—	18,565	—	—	—	18,565
Tax expense related to stock-based compensation	—	—	(3,004)	—	—	—	(3,004)
Payment of cash dividends	—	—	—	(30,681)	—	—	(30,681)
Purchase of treasury stock	—	—	—	—	—	(1,623)	(1,623)
Balance, December 31, 2009	180,829	1,808	781,635	1,901,853	14,996	(618,592)	2,081,700
Comprehensive income:							
Net income	—	—	—	116,942	—	—	116,942
Foreign currency translation adjustment, (net of tax of $2,814)	—	—	—	—	6,601	—	6,601
Total comprehensive income	—	—	—	116,942	6,601	—	123,543
Issuance of restricted stock	700	7	(7)	—	—	—	—
Vesting of restricted stock units	7	—	—	—	—	—	—
Forfeitures of restricted stock	(59)	(1)	1	—	—	—	—
Exercise of stock options	61	1	524	—	—	—	525
Stock-based compensation	—	—	16,779	—	—	—	16,779
Tax expense related to stock-based compensation	—	—	(2,291)	—	—	—	(2,291)
Payment of cash dividends	—	—	—	(30,796)	—	—	(30,796)
Purchase of treasury stock	—	—	—	—	—	(1,853)	(1,853)
Balance, December 31, 2010	181,538	$1,815	$796,641	$1,987,999	$ 21,597	$(620,445)	$2,187,607

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2010	2009	2008
		(In thousands)	
Cash flows from operating activities:			
Net income (loss)	$ 116,942	$ (38,290)	$ 347,069
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and impairment	333,493	289,847	275,990
Provision for bad debts	(2,000)	3,810	4,350
Dry holes and abandonments	519	129	1,617
Deferred income tax expense	147,490	101,443	65,392
Stock-based compensation expense	16,779	18,214	19,688
Net (gain) loss on asset disposals	(22,812)	3,385	(4,163)
Tax expense related to stock-based compensation	(2,291)	(3,004)	—
Changes in operating assets and liabilities:			
Accounts receivable	(178,444)	213,813	(30,777)
Income taxes receivable/payable	43,522	(108,664)	(11,258)
Inventory and other assets	(8,772)	14,178	2,498
Accounts payable	49,576	(52,673)	6,486
Accrued expenses	18,072	(21,178)	(4,474)
Other liabilities	3,234	(92)	1,242
Net cash provided by operating activities of discontinued operations	10,390	32,759	1,344
Net cash provided by operating activities	525,698	453,677	675,004
Cash flows from investing activities:			
Acquisitions	(238,022)	—	—
Purchases of property and equipment	(738,090)	(452,646)	(445,426)
Proceeds from disposal of assets	29,409	3,359	11,436
Net cash provided by (used in) investing activities of discontinued operations	42,638	(54)	(3,286)
Net cash used in investing activities	(904,065)	(449,341)	(437,276)
Cash flows from financing activities:			
Purchases of treasury stock	(1,853)	(1,623)	(70,818)
Dividends paid	(30,796)	(30,681)	(92,865)
Tax benefit related to stock-based compensation	—	—	16,280
Proceeds from long term debt	400,000	—	—
Repayment of long term debt	(1,250)	—	—
Proceeds from borrowings under revolving credit facility	200,000	—	—
Repayment of borrowings under revolving credit facility	(200,000)	—	(50,000)
Debt issuance costs	(10,779)	(6,169)	—
Proceeds from exercise of stock options	525	569	25,548
Net cash provided by (used in) financing activities	355,847	(37,904)	(171,855)
Effect of foreign exchange rate changes on cash	255	2,222	(2,084)
Net increase (decrease) in cash and cash equivalents	(22,265)	(31,346)	63,789
Cash and cash equivalents at beginning of year	49,877	81,223	17,434
Cash and cash equivalents at end of year	$ 27,612	$ 49,877	$ 81,223
Supplemental disclosure of cash flow information:			
Net cash (paid) received during the year for:			
Interest expense, net of capitalized interest of $2,288 in 2010, $0 in 2009 and $0 in 2008	$ —	$ (1,804)	$ (323)
Income taxes	115,666	14,029	(126,331)
Non-cash investing and financing activities:			
Net increase (decrease) in payables for purchases of property and equipment	$ 29,188	$ (25,110)	$ (3,590)
Net (increase) decrease in deposits on equipment purchases	(50,170)	43,029	(42,293)

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

1. Description of Business and Summary of Significant Accounting Policies

A description of the business and basis of presentation follows:

Description of business — Patterson-UTI Energy, Inc., through its wholly-owned subsidiaries (collectively referred to herein as "Patterson-UTI" or the "Company"), provides onshore contract drilling services to major and independent oil and natural gas operators primarily in Texas, New Mexico, Oklahoma, Arkansas, Louisiana, Mississippi, Colorado, Utah, Wyoming, Montana, North Dakota, Pennsylvania, West Virginia and western Canada. The Company provides pressure pumping services primarily in Texas and the Appalachian Basin. The Company also owns and invests in oil and natural gas assets as a working interest owner primarily in Texas and New Mexico.

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 other 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 the 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 as revenue reimbursements received from third parties for out-of-pocket expenses and accounts for those out-of-pocket expenses as direct costs. Except for two wells drilled under footage contracts in 2009, all of the wells the Company drilled during the years ended December 31, 2010, 2009 and 2008 were under daywork contracts.

Accounts receivable — Trade accounts receivable are recorded at the invoiced amount. 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.

Inventories — Inventories consist primarily of sand and chemical products to be used in conjunction with the Company's 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 whenever 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 economic viability of the respective projects. If no progress has been made in assessing the reserves and economic viability of a project after one year following the completion of drilling, the Company considers the well costs 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 for each respective field.

The Company reviews its proved oil and natural gas properties for impairment whenever 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 management's expectation of future pricing over the lives of the respective fields. These cash flow estimates are 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 net book value and discounted cash flow. The discounted cash flow estimates used in measuring impairment are based on management's expectations of future commodity prices over the life of the respective field. The Company reviews unproved oil and natural gas properties quarterly to assess potential impairment. The Company's impairment assessment is made on a lease-by-lease basis and considers factors such as management's intent to drill, lease terms and abandonment of an area. If an unproved property is determined to be impaired, the related property costs are expensed.

Goodwill — Goodwill is considered to have an indefinite useful economic life and is not amortized. The Company assesses impairment of its goodwill at least annually as of December 31, or on an interim basis if events or circumstances indicate that the fair value of goodwill may have decreased below its carrying value.

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 — Upon disposition 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 operations.

Net income (loss) per common share — The Company provides a dual presentation of its net income (loss) per common share in its consolidated statements of operations: Basic net income (loss) per common share ("Basic EPS") and diluted net income (loss) per common share ("Diluted EPS"). The Company adopted a new accounting standard on January 1, 2009, which clarified 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 earnings-per-share using the two-class method. All earnings-per-share data presented for the year ended December 31, 2008 have been adjusted retrospectively to conform with this accounting standard.

The impact of this retrospective application to the year ended December 31, 2008 was to reduce Basic EPS and Diluted EPS by $0.01.

Basic EPS excludes dilution and is computed by first allocating earnings between common stockholders and holders of non-vested shares of restricted stock. Basic EPS is then determined by dividing the earnings attributable to common stockholders by the weighted average number of common shares outstanding during the period, excluding non-vested shares of restricted stock.

Diluted EPS is based on the weighted average number of common shares outstanding plus the dilutive effect of potential common shares, including stock options, non-vested shares of restricted stock and restricted stock units. The dilutive effect of stock options and restricted stock units is determined using the treasury stock method. The dilutive effect of non-vested shares of restricted stock is based on the more dilutive of the treasury stock method or the two-class method, assuming a reallocation of undistributed earnings to common stockholders after considering the dilutive effect of potential common shares other than non-vested shares of restricted stock.

The following table presents information necessary to calculate income (loss) from continuing operations per share, loss from discontinued operations per share and net income (loss) per share for the years ended December 31, 2010, 2009 and 2008, as well as potentially dilutive securities excluded from the weighted average number of diluted common shares outstanding because their inclusion would have been anti-dilutive (in thousands, except per share amounts):

	2010	2009	2008
BASIC EPS:			
Income (loss) from continuing operations	$117,898	$ (33,960)	$353,868
Adjust for (income) loss attributed to holders of non-vested restricted stock	(884)	313	(3,279)
Income (loss) from continuing operations attributed to common stockholders	$117,014	$ (33,647)	$350,589
Loss from discontinued operations, net	$ (956)	$ (4,330)	$ (6,799)
Adjust for loss attributed to holders of non-vested restricted stock	7	38	64
Loss from discontinued operations attributed to common stockholders	$ (949)	$ (4,292)	$ (6,735)
Weighted average number of common shares outstanding, excluding non-vested shares of restricted stock	152,772	152,069	153,379
Basic income (loss) from continuing operations per common share	$ 0.77	$ (0.22)	$ 2.29
Basic loss from discontinued operations per common share	$ (0.01)	$ (0.03)	$ (0.04)
Basic net income (loss) per common share	$ 0.76	$ (0.25)	$ 2.25

	2010	2009	2008
DILUTED EPS:			
Income (loss) from continuing operations attributed to common stockholders	$117,014	$ (33,647)	$350,589
Add incremental earnings related to potential common shares	—	—	15
Adjusted income (loss) from continuing operations attributed to common stockholders	$117,014	$ (33,647)	$350,604
Weighted average number of common shares outstanding, excluding non-vested shares of restricted stock	152,772	152,069	153,379
Add dilutive effect of potential common shares	504	—	979
Weighted average number of diluted common shares outstanding	153,276	152,069	154,358
Diluted income (loss) from continuing operations per common share	$ 0.76	$ (0.22)	$ 2.27
Diluted loss from discontinued operations per common share	$ (0.01)	$ (0.03)	$ (0.04)
Diluted net income (loss) per common share	$ 0.76	$ (0.25)	$ 2.23
Potentially dilutive securities excluded as anti-dilutive	4,164	8,090	2,455

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's policy is to account for interest and penalties with respect to income taxes as operating expenses.

Stock-based compensation — The Company recognizes the cost of share-based payments under the fair-value-based method. Under this method, compensation cost related to share-based payments is measured based on the estimated fair value of the awards at the date of grant, net of estimated forfeitures. This expense is recognized over the expected life of the awards (See Note 11).

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 June 2009, the FASB issued a new accounting standard that amends the accounting and disclosure requirements for the consolidation of variable interest entities. This new standard removes the previously existing exception from applying consolidation guidance to qualifying special-purpose entities and requires ongoing reassessments of whether an enterprise is the primary beneficiary of a variable interest entity. Prior to this new standard, generally accepted accounting principles required reconsideration of whether an enterprise is the primary beneficiary of a variable interest entity only when specific events occurred. This new standard is effective as of the beginning of each reporting entity's first annual reporting period that begins after November 15, 2009, for interim periods within that first annual reporting period, and for interim and annual reporting periods thereafter. This new standard became effective for the Company on January 1, 2010. The adoption of this standard did not impact the Company's consolidated financial statements.

In October 2009, the FASB issued a new accounting standard that addresses the accounting for multiple-deliverable revenue arrangements to enable vendors to account for deliverables separately rather than as a combined unit. This new standard addresses how to separate deliverables and how to measure and allocate arrangement consideration to one or more units of accounting. Existing accounting standards require a vendor to use objective and reliable evidence of fair value for the undelivered items or the residual method to separate deliverables in a multiple-deliverable arrangement. Under the new standard, it is expected that multiple-deliverable arrangements will be separated in more circumstances than under current requirements. The new standard establishes a hierarchy for determining the selling price of a deliverable for purposes of allocating revenue to multiple deliverables. The selling price used will be based on vendor-specific objective evidence if available, third-party evidence if vendor-specific objective evidence is not available, or estimated selling price if neither vendor-specific objective evidence nor third-party evidence is available. The new standard must be prospectively applied to all revenue arrangements entered into in fiscal years beginning on or after June 15, 2010 and became effective for the Company on January 1, 2011. The adoption of this standard is not expected to have a material impact on the Company's consolidated financial position, results of operations or cash flows.

In December 2010, the FASB issued an accounting standard update that addresses the disclosure of supplementary pro forma information for business combinations. This update clarifies that when public entities are required to disclose pro forma information for business combinations that occurred in the current reporting period, the pro forma information should be presented as if the business combination occurred as of the beginning of the previous fiscal year when comparative financial statements are presented. This update is effective prospectively 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, 2010. Early adoption is permitted. The Company elected to early adopt this update and this early adoption did not have an impact on the Company's consolidated financial position, results of operations or cash flows.

Reclassifications — Certain reclassifications have been made to the 2009 and 2008 consolidated financial statements in order for them to conform with the 2010 presentation. These reclassifications had no significant impact on the Company's financial position, results of operations or cash flows.

2. Discontinued Operations

On January 27, 2011, the stock of the Company's electric wireline subsidiary, Universal Wireline, Inc., was sold in a cash transaction for $25.5 million. Except for inventory, the working capital of Universal Wireline, Inc. was excluded from the sale and retained by a subsidiary of the Company. Universal Wireline, Inc. was formed in 2010 to acquire the electric wireline business of Key Energy Services, Inc., as discussed in Note 3. The results of operations of this business have been presented as results of discontinued operations in these consolidated financial statements. As of December 31, 2010, the assets to be disposed of were classified as held for sale and are presented separately within current assets under the caption "Assets held for sale" in the consolidated balance sheet. Upon being classified as held for sale, the assets to be disposed of were recorded at fair value less estimated costs to sell resulting in a charge of $2.2 million. Due to the fact that the carrying value of the assets had been adjusted to net realizable value, no significant additional gain or loss was recognized in connection with the sale.

On January 20, 2010, the Company exited the drilling and completion fluids business, which had previously been presented as one of the Company's reportable operating segments. On that date, the Company's wholly owned subsidiary, Ambar Lone Star Fluids Services LLC, completed the sale of substantially all of its assets, excluding billed accounts receivable. The sales price was approximately $42.6 million. Upon the Company's exit from the drilling and completion fluids business, the Company classified its drilling and completion fluids operating segment as a discontinued operation. Accordingly, the results of operations of this business have been reclassified and presented as results of discontinued operations for all periods presented in these consolidated financial statements. As of December 31, 2009, the assets to be disposed of were considered held for sale and were presented separately within current assets under the caption "Assets held for sale" in the consolidated balance sheet. Upon being classified as held for sale, the assets to be disposed of were adjusted to fair value less estimated costs to sell resulting in an impairment loss of $1.9 million. Due to the fact that the carrying value of the assets had been adjusted to net realizable value, no significant additional gain or loss was recognized in connection with the sale in 2010.

Summarized operating results from discontinued operations for the years ended December 31, 2010, 2009 and 2008 are shown below (in thousands):

	2010	2009	2008
Drilling and completion fluids revenues	$ 3,737	$79,786	$145,246
Electric wireline revenues	5,712	—	—
Operating revenues from discontinued operations	$ 9,449	$79,786	$145,246
Loss before income taxes	$(1,499)	$ (6,538)	$ (4,410)
Income tax benefit (expense)	543	2,208	(2,389)
Loss from discontinued operations	$ (956)	$ (4,330)	$ (6,799)

The loss before income taxes in 2008 includes approximately $10.0 million in non-deductible charges resulting from the impairment of goodwill. As a result, income tax expense was incurred for the year despite the fact that the discontinued operation had a pre-tax book loss.

The components of assets held for sale at December 31, 2010 and 2009 are shown below (in thousands):

	2010	2009
Assets held for sale:		
Inventory	$ 756	$28,620
Unbilled accounts receivable	—	6,587
Prepaid expenses and other current assets	—	324
Property and equipment, net	24,769	8,793
Reserve to reduce disposal group to fair value less costs to sell	(2,155)	(1,900)
Total assets held for sale	$23,370	$42,424

3. Acquisitions

On October 1, 2010, two subsidiaries of the Company, Universal Pressure Pumping, Inc. and Universal Wireline, Inc., completed the acquisition of certain assets from Key Energy Pressure Pumping Services, LLC and Key Electric Wireline Services, LLC relating to the businesses of providing pressure pumping services and electric wireline services to participants in the oil and natural gas industry. This acquisition expanded the Company's pressure pumping operations to additional markets primarily in Texas. The aggregate purchase price was $241 million consisting of a cash payment of $238 million at closing funded through a combination of cash on hand and a $200 million draw on the Company's revolving credit facility, a subsequent cash payment based on the value of closing inventory of approximately $1.2 million to be made in the first quarter of 2011 and the assumption of liabilities of approximately $2.1 million. The purchase price was allocated to the tangible and identifiable intangible assets acquired and liabilities assumed based on fair value. The tangible assets acquired include property and equipment, inventories of sand and chemicals on hand and repair and maintenance supplies on hand. The identifiable intangible assets acquired include an agreement by the seller to not compete for a period of three years and the customer relationships in place at the time of the acquisition. The liabilities assumed arose from pricing agreements in place with certain customers that had pricing below current market rates. A related deferred tax asset was recognized to reflect the temporary difference associated with these below-market pricing arrangements. The excess of the purchase price over the fair values of the tangible assets, the identifiable intangible assets and deferred tax asset, net of the liabilities assumed is recorded as goodwill and was attributed to the pressure pumping business acquired. A summary of the purchase price allocation follows (in thousands):

Sand and chemical inventory	$ 6,848
Supplies	312
Property and equipment	154,359
Non-compete agreement	1,400
Customer relationships	25,500
Deferred tax asset	8,514
Goodwill	67,575
Below-market pricing agreements	(23,200)
Total purchase price	$241,308

In addition to the purchase price, acquisition-related expenses associated with this transaction of approximately $2.5 million were incurred by the Company and are presented in the consolidated statement of operations under the caption "acquisition-related expenses" for the year ended December 31, 2010. These expenses include certain legal and other professional fees directly related to the transaction, fees incurred in connection with title transfers of the acquired equipment and transition costs related to information technology.

As discussed in Note 2, the electric wireline business was classified as held for sale at December 31, 2010 and was subsequently sold on January 27, 2011. The results of operations of the wireline business from the date of acquisition included revenue of $5.7 million and a pre-tax operating loss of $1.5 million (including a charge of approximately $2.2 million incurred to reduce the carrying value of the disposal group to its net realizable value) which is included in loss from discontinued operations for the year ended December 31, 2010. Results of operations of the acquired pressure pumping business are included in the Company's consolidated results of operations from the date of acquisition. Revenues of $84.7 million and income from operations of $22.8 million from the acquired pressure pumping business are included in the consolidated statement of operations for the year ended December 31, 2010.

The following represents pro-forma unaudited financial information for the years ended December 31, 2010 and 2009 as if the acquisition had been completed on January 1, 2009 (in thousands, except per share amounts):

	2010	2009
	(Unaudited)	
Revenue	$1,660,635	$905,168
Income (loss) from continuing operations	$ 127,257	$ (46,807)
Net income (loss)	$ 126,301	$ (51,137)
Basic income (loss) from continuing operations per common share	$ 0.83	$ (0.33)
Basic net income (loss) per common share	$ 0.83	$ (0.36)
Diluted income (loss) from continuing operations per common share	$ 0.82	$ (0.33)
Diluted net income (loss) per common share	$ 0.82	$ (0.36)

4. Property and Equipment

Property and equipment consisted of the following at December 31, 2010 and 2009 (in thousands):

	2010	2009
Equipment	$ 3,972,891	$ 3,230,737
Oil and natural gas properties	110,749	93,354
Buildings	61,425	56,563
Land	11,074	9,795
	4,156,139	3,390,449
Less accumulated depreciation and depletion	(1,535,239)	(1,280,047)
Property and equipment, net	$ 2,620,900	$ 2,110,402

Depreciation, depletion, amortization and impairment — The following table summarizes depreciation, depletion, amortization and impairment expense related to property and equipment and intangible assets for 2010, 2009 and 2008 (in millions):

	2010	2009	2008
Depreciation and impairment expense	$322.3	$280.6	$264.5
Amortization expense	1.0	—	—
Depletion expense	10.2	9.2	11.5
Total	$333.5	$289.8	$276.0

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 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 and a significant decline in oil and natural gas commodity prices, the Company deemed it necessary to assess the recoverability of long-lived assets within its contract drilling segment in 2008. Due to a continued decrease in the operating levels within its contract drilling business segment through the first three quarters of 2009, the Company again deemed it necessary to perform an impairment assessment of long-lived assets in its contract drilling segment in 2009. In light of the recent favorable trends in rig utilization and revenue per operating day experienced by the Company and its peers, management concluded that no triggering event had occurred in 2010 with respect to its contract drilling segment. With respect to the long-lived assets in the Company's oil and natural gas exploration and production segment, the Company assesses the recoverability of long-lived assets at the end of each quarter due to revisions in its oil and natural gas reserve estimates and expectations about future commodity prices. The Company concluded that its pressure pumping segment was not subject to the negative events and trends to the same degree as the contract drilling segment, and thus did not require further assessment of recoverability in 2010, 2009 or 2008.

The Company performs the first step of its impairment assessments by comparing the undiscounted cash flows for each long-lived asset or asset group to its respective carrying value. Based on the results of these impairment tests, the carrying amounts of long-lived assets in the contract drilling and oil and natural gas segments were determined to be recoverable, except as described below.

The Company's analysis indicated that the carrying amounts of certain oil and natural gas properties were not recoverable at various testing dates in 2010, 2009 and 2008. The Company's estimates of expected future net cash flows from impaired properties are used in measuring the fair value of such properties. The Company recorded impairment charges of $792,000, $3.7 million and $4.4 million in 2010, 2009 and 2008, respectively, related to its oil and natural gas properties. The Company determined the fair value of the impaired assets using internally developed unobservable inputs including future pricing and reserves (level 3 inputs in the fair value hierarchy of fair value accounting).

During 2010, 2009 and 2008, in connection with its long-term planning process, the Company evaluated its then-current fleet of marketable drilling rigs and identified four, 23 and 22 rigs, respectively, that it determined would no longer be marketed as rigs. The components comprising these rigs were evaluated, and those components with continuing utility to the Company's other marketed rigs were transferred to other rigs or yards to be used as spare equipment. The remaining components of these rigs were impaired and the associated net book value of $4.2 million in 2010, $10.5 million in 2009 and $10.4 million in 2008 was expensed in the Company's consolidated statements of operations as an impairment charge. The impaired components were estimated to have no fair value.

During 2010, the Company sold certain rights to explore and develop zones deeper than depths that it generally targets for certain of the oil and natural gas properties in which it has working interests. The proceeds from this sale were approximately $22.3 million and the sale resulted in a gain on disposal of $20.1 million.

5. Goodwill and Intangible Assets

Goodwill — Goodwill by operating segment as of December 31, 2010 and 2009 and changes for the years then ended are as follows (in thousands):

	2010	2009
Contract Drilling:		
Balance as of January 1:		
Goodwill	$ 86,234	$86,234
Accumulated impairment losses	—	—
	86,234	86,234
Changes to goodwill	—	—
Balance as of December 31:		
Goodwill	86,234	86,234
Accumulated impairment losses	—	—
	86,234	86,234
Pressure Pumping:		
Balance as of January 1:		
Goodwill	—	—
Accumulated impairment losses	—	—
Goodwill recorded in connection with business combination	67,575	—
Balance as of December 31:		
Goodwill	67,575	—
Accumulated impairment losses	—	—
	67,575	—
Total goodwill as of December 31	$153,809	$86,234

Goodwill recorded in connection with a business combination in 2010 was a result of the Company's acquisition of the pressure pumping business of Key Energy Services, Inc. on October 1, 2010, as discussed further in Note 3. Approximately $53.2 million of this goodwill is expected to be deductible for tax purposes.

Goodwill is evaluated at least annually on December 31 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.

The Company performed its annual goodwill impairment assessment as of December 31, 2009 related to the $86.2 million in goodwill recorded in its contract drilling reporting unit. In completing its first step of the analysis, the Company 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 the reporting unit. In developing this fair value estimate, the Company applied key assumptions, including an assumed discount rate of 15.42% and an assumed long-term growth rate of 3.50%. Based on the results of the first step of the impairment test in 2009, the Company concluded that no impairment was indicated in its contract drilling reporting unit as the estimated fair value of that reporting unit exceeded its carrying value.

The Company performed its annual goodwill impairment assessment as of December 31, 2010. In completing its first step of the analysis, the Company estimated its enterprise value based on the market capitalization of the Company as determined by reference to the closing price of the Company's common stock during the fifteen days before and after year end. The enterprise value was allocated to the Company's reporting units and it was determined that the fair values of the Company's reporting units were in excess of their carrying value. As a result, the Company concluded that no impairment of goodwill was indicated as of December 31, 2010.

In the event that market conditions weaken, the Company may determine additional impairments of goodwill in its contract drilling or pressure pumping reporting units in the future, and such impairment could be material.

Intangible Assets — Intangible assets were recorded in the pressure pumping operating segment in connection with the fourth quarter 2010 acquisition of the assets of the pressure pumping business discussed in Note 3. As a result of the purchase price allocation, the Company recorded intangible assets related to a non-compete agreement and the customer relationships acquired. These intangible assets were recorded at fair value on the date of acquisition.

The non-compete agreement has a term of three years from October 1, 2010. The value of this agreement was estimated using a with and without scenario where cash flows were projected through the term of the agreement assuming the agreement is in place and compared to cash flows assuming the non-compete agreement was not in place. The intangible asset associated with the non-compete agreement is being amortized on a straight-line basis over the three-year term of the agreement. Amortization expense of $116,000 was recorded in the year ended December 31, 2010 associated with the non-compete agreement.

The value of the customer relationships was estimated using a multi-period excess earnings model to determine the present value of the projected cash flows associated with the customers in place at the time of the acquisition and taking into account a contributory asset charge. The resulting intangible asset is being amortized on a straight-line basis over seven years. Amortization expense of $910,000 was recorded in the year ended December 31, 2010 associated with customer relationships.

The following table sets forth the activity with respect to intangible assets for the year ended December 31, 2010 (in thousands):

	Non-compete	Customer Relationships	Total
Intangible assets at January 1, 2010	$ —	$ —	$ —
Intangible assets recognized at fair value in business combination	1,400	25,500	26,900
Amortization expense	(116)	(910)	(1,026)
Accumulated amortization at December 31, 2010	(116)	(910)	(1,026)
Intangible assets, net at December 31, 2010	$1,284	$24,590	$25,874

6. Accrued Expenses

Accrued expenses consisted of the following at December 31, 2010 and 2009 (in thousands):

	2010	2009
Salaries, wages, payroll taxes and benefits	$ 39,766	$ 15,657
Workers' compensation liability	63,011	65,825
Sales, use and other taxes	6,782	11,090
Insurance, other than workers' compensation	12,648	12,498
Deferred revenue — current	10,220	—
Other	14,888	3,680
	$147,315	$108,750

Deferred revenue was recorded in 2010 in the purchase price allocation associated with the Company's acquisition of a pressure pumping business as discussed in Note 3. The deferred revenue relates to out-of-market pricing agreements that were in place at the acquired business at the time of the acquisition. The deferred revenue will be recognized as pressure pumping revenue over the remaining term of the pricing agreements. Deferred revenue of approximately $6.1 million was recognized in the year ended December 31, 2010 related to these pricing agreements.

7. Asset Retirement Obligation

The Company records 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" in the liabilities section of the consolidated balance sheet. The following table describes the changes to the Company's asset retirement obligations during 2010 and 2009 (in thousands):

	2010	2009
Balance at beginning of year	$2,955	$3,047
Liabilities incurred	335	157
Liabilities settled	(339)	(354)
Accretion expense	112	118
Revision in estimated costs of plugging oil and natural gas wells	—	(13)
Asset retirement obligation at end of year	$3,063	$2,955

8. Long Term Debt

In March 2009, the Company entered into an unsecured revolving credit facility (the "2009 Credit Facility") with a maximum borrowing capacity of $240 million. The Company incurred debt issuance costs of approximately $6.2 million during 2009 in connection with the 2009 Credit Facility. These costs were being amortized to interest expense over the contractual term of the 2009 Credit Facility.

On July 2, 2010, the Company entered into a 364-Day Credit Agreement (the "364-Day Credit Agreement") among the Company, as borrower, and Wells Fargo Bank, N.A., as administrative agent and lender. The 364-Day Credit Agreement was a committed senior unsecured single draw term loan credit facility that permitted a borrowing of up to $250 million, provided that the loan must have been drawn no later than September 30, 2010 or, if an additional fee was paid, October 30, 2010. The maturity date under the 364-Day Credit Agreement was 364 days after the date on which the closing conditions under the 364-Day Credit Agreement were met. This facility was not drawn as of September 30, 2010 and it expired at that time.

On August 19, 2010, the Company entered into a Credit Agreement (the "2010 Credit Agreement") among the Company, as borrower, Wells Fargo Bank, N.A., as administrative agent, letter of credit issuer, swing line lender and lender, and each of the other letter of credit issuer and lender parties thereto. The 2010 Credit Agreement is a committed senior unsecured credit facility that includes a revolving credit facility and a term loan facility. The 2010 Credit Agreement replaced the 2009 Credit Facility.

The revolving credit facility permits aggregate borrowings of up to $400 million and contains a letter of credit facility that is limited to $150 million and a swing line facility that is limited to $40 million. Subject to customary conditions, the Company may request that the lenders' aggregate commitments with respect to the revolving credit facility be increased by up to $100 million, not to exceed total commitments of $500 million. The maturity date for the revolving facility is August 19, 2013.

The term loan facility provided for a loan of $100 million which was funded on August 19, 2010. The term loan facility is payable in quarterly principal installments commencing November 19, 2010, and the installment amounts vary from 1.25% of the original principal amount for each of the first four quarterly installments, 2.50% of the original principal amount for each of the subsequent eight quarterly installments, 5.00% of the original principal amount for the next subsequent three quarterly installments and the remainder is due at maturity. The maturity date for the term loan facility is August 19, 2014.

Loans under the 2010 Credit Agreement bear interest by reference, at the Company's election, to the LIBOR rate or base rate. The applicable margin on LIBOR rate loans varies from 2.75% to 3.75% and the applicable margin on base rate loans varies from 1.75% to 2.75%, in each case determined based upon the Company's debt to capitalization ratio. As of December 31, 2010, the applicable margin on LIBOR rate loans was 2.75% and the applicable margin on base rate loans was 1.75%. A letter of credit fee is payable by the Company equal to the applicable margin for LIBOR rate loans times the daily amount available to be drawn under outstanding letters of credit. The commitment fee payable to the lenders for the unused portion of the revolving credit facility varies from 0.50% to 0.75% based upon the Company's debt to capitalization ratio and was 0.50% as of December 31, 2010.

Each domestic subsidiary of the Company other than any immaterial subsidiary has unconditionally guaranteed all existing and future indebtedness and liabilities of the Company and the other guarantors arising under the 2010 Credit Agreement and other loan documents. Such guarantees also cover obligations of the Company and any subsidiary of the Company arising under any interest rate swap contract with any person while such person is a lender or affiliate of a lender under the 2010 Credit Agreement.

The 2010 Credit Agreement contains customary representations, warranties, indemnities and affirmative and negative covenants. The 2010 Credit Agreement also requires compliance with two financial covenants. The Company must not permit its debt to capitalization ratio to exceed 45% at any time. The 2010 Credit Agreement generally defines the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. The Company also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 3.00 to 1.00. The 2010 Credit Agreement generally defines the interest coverage ratio as the ratio of earnings before interest, taxes, depreciation and amortization ("EBITDA") of the four prior fiscal quarters to interest charges for the same period. The Company does not expect that the restrictions and covenants will impact its ability to operate or react to opportunities that might arise.

As of December 31, 2010, the Company had $98.8 million principal amount outstanding under the term loan facility at an interest rate of 3.125% and no borrowings outstanding under the revolving credit facility. The Company had $41.2 million in letters of credit outstanding at December 31, 2010 and, as a result, had available borrowing capacity of approximately $359 million at that date.

Senior Notes — On October 5, 2010, the Company completed the issuance and sale of $300 million in aggregate principal amount of its 4.97% Series A Senior Notes due October 5, 2020 (the "Notes") in a private placement. A portion of the proceeds from the Notes was used to repay a $200 million borrowing on the Company's revolving credit facility, which had been drawn to fund a portion of the acquisition that closed on October 1, 2010 as discussed in Note 3. The Notes are senior unsecured obligations of the Company which rank equally in right of payment with all other unsubordinated indebtedness of the Company. The Notes are guaranteed on a senior unsecured basis by each of the existing domestic subsidiaries of the Company other than immaterial subsidiaries.

The Notes bear interest at a rate of 4.97% per annum and were priced at 100% of the principal amount of the Notes. The Company will pay interest on the Notes on April 5 and October 5 of each year commencing on April 5,

2011. The Notes will mature on October 5, 2020. The Notes are prepayable at the Company's option, in whole or in part, provided that in the case of a partial prepayment, prepayment must be in an amount not less than 5% of the aggregate principal amount of the Notes then outstanding, at any time and from time to time at 100% of the principal amount prepaid, plus accrued and unpaid interest to the prepayment date, plus a "make-whole" premium as specified in the note purchase agreement. The Company must offer to prepay the Notes upon the occurrence of any change of control. In addition, the Company must offer to prepay the Notes upon the occurrence of certain asset dispositions if the proceeds therefrom are not timely reinvested in productive assets. If any offer to prepay is accepted, the purchase price of each prepaid Note is 100% of the principal amount thereof, plus accrued and unpaid interest thereon to the prepayment date.

The note purchase agreement requires compliance with two financial covenants. The Company must not permit its debt to capitalization ratio to exceed 50% at any time. The note purchase agreement generally defines the debt to capitalization ratio as the ratio of (a) total borrowed money indebtedness to (b) the sum of such indebtedness plus consolidated net worth, with consolidated net worth determined as of the last day of the most recently ended fiscal quarter. The Company also must not permit the interest coverage ratio as of the last day of a fiscal quarter to be less than 2.50 to 1.00. The note purchase agreement generally defines the interest coverage ratio as the ratio for the four prior quarters of EBITDA to interest charges for that same period. The Company does not expect that the restrictions and covenants will impair its ability to operate or react to opportunities that might arise.

Events of default under the note purchase agreement include failure to pay principal or interest when due, failure to comply with the financial and operational covenants, a cross default event, a judgment in excess of a threshold event, the guaranty agreement ceasing to be enforceable, the occurrence of certain ERISA events, a change of control event and bankruptcy and other insolvency events. If an event of default occurs and is continuing, then holders of a majority in principal amount of the Notes have the right to declare all the Notes then-outstanding to be immediately due and payable. In addition, if the Company defaults in payments on any Note, then until such defaults are cured, the holder thereof may declare all the Notes held by it to be immediately due and payable.

During the year ended December 31, 2010, the Company incurred approximately $10.8 million in debt issuance costs in connection with the 2010 Credit Agreement and the Senior Notes discussed above. These costs were deferred and will be recognized as interest expense over the term of the underlying debt. For the year ended December 31, 2010, interest expense related to the amortization of debt issuance costs for the 2010 Credit Agreement and the Senior Notes was approximately $1.1 million.

Presented below is a schedule of the principal repayment requirements of long-term debt by fiscal year as of December 31, 2010 (in thousands):

Year ending December 31,	
2011	$ 6,250
2012	10,000
2013	12,500
2014	70,000
2015	—
Thereafter	300,000
Total	$398,750

9. Commitments, Contingencies and Other Matters

Commitments — As of December 31, 2010, the Company maintained letters of credit in the aggregate amount of $41.2 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 annually at various times during the year and are typically renewed. As of December 31, 2010, no amounts had been drawn under the letters of credit.

As of December 31, 2010, the Company had commitments to purchase approximately $267 million of major equipment.

Contingencies — The Company's contract services operations are subject to inherent risks, including blow-outs, 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, subject to a $2.0 million self-insured retention, general liability insurance coverage, 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, and automobile liability insurance coverages. Accrued expenses related to insurance claims are set forth in Note 6.

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 personal injury, well disasters, extensive fire damage, or damage to the environment. The Company also carries insurance to cover physical damage to, or loss of, its equipment. However, it does not cover the full replacement cost of the equipment 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, if at all.

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.

10. Stockholders' Equity

Cash Dividends — The Company paid cash dividends during the years ended December 31, 2008, 2009 and 2010 as follows:

	Per Share	Total (in thousands)
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
2009:		
Paid on March 31, 2009	$0.05	$ 7,655
Paid on June 30, 2009	0.05	7,675
Paid on September 30, 2009	0.05	7,675
Paid on December 30, 2009	0.05	7,676
Total cash dividends	$0.20	$30,681
2010:		
Paid on March 30, 2010	$0.05	$ 7,677
Paid on June 30, 2010	0.05	7,706
Paid on September 30, 2010	0.05	7,704
Paid on December 30, 2010	0.05	7,709
Total cash dividends	$0.20	$30,796

On February 2, 2011, 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 30, 2011 to holders of record as of March 15, 2011. 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.

On August 1, 2007, the Company's Board of Directors approved a stock buyback 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, 2008, the Company purchased 3,502,047 shares of its common stock under the program at a cost of approximately $66.3 million. During the year ended December 31, 2009, the Company purchased 5,715 shares of its common stock under the program at a cost of approximately $79,000. During the year ended December 31, 2010, the Company purchased 8,743 shares of its common stock under the program at a cost of approximately $123,000. As of December 31, 2010, the Company is authorized to purchase approximately $113 million of the Company's outstanding common stock under the program. Shares purchased under the program are accounted for as treasury stock.

The Company purchased 117,083, 114,983 and 152,235 shares of treasury stock from employees during 2010, 2009 and 2008, 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 $1.7 million, $1.5 million and $4.5 million in 2010, 2009 and 2008, 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 program.

11. Stock-based Compensation

The Company uses share-based payments to compensate employees and non-employee directors. The Company recognizes the cost of share-based payments under the fair-value-based method. Share-based awards consist of equity instruments in the form of stock options, restricted stock or restricted stock units and have included service and, in certain cases, performance conditions. The Company's share-based awards also include both cash-settled and share-settled performance unit awards. Cash-settled performance unit awards are accounted for as liability awards. Share-settled performance unit awards are accounted for as equity awards. The Company issues shares of common stock when vested stock options are exercised, when restricted stock is granted and when restricted stock units and share-settled performance unit awards vest.

The Company's shareholders have 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 2010, the Company amended the 2005 Plan to, among other things, increase the total number of shares authorized for grant from 10,250,000 to 15,250,000. The Company's share-based compensation plans at December 31, 2010 follow:

Plan Name	Shares Authorized for Grant	Awards Outstanding	Shares Available for Grant
Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan, as amended	15,250,000	5,830,135	5,763,314
Patterson-UTI Energy, Inc. Amended and Restated 1997 Long-Term Incentive Plan, as amended ("1997 Plan")	—	2,843,300	—
Amended and Restated Patterson-UTI Energy, Inc. 2001 Long-Term Incentive Plan ("2001 Plan")	—	168,552	—

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 one year for non-employee directors and three to four years for employees.
- The Compensation Committee sets the term of awards and no option term can exceed 10 years.
- All options granted under the plan are granted with an exercise price equal to or greater than the fair market value of the Company's common stock at the time the option is granted.
- The plan provides for awards of incentive stock options, non-incentive stock options, tandem and free-standing stock appreciation rights, restricted stock awards, other stock unit awards, performance share awards, performance unit awards and dividend equivalents. As of December 31, 2010, non-incentive stock options, restricted stock awards, restricted stock units and performance unit awards had been granted under the plan.

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

Stock Options — The Company estimates the grant date fair values of stock options using the Black-Scholes-Merton valuation model. 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, 2010, 2009 and 2008 follow:

	2010	2009	2008
Volatility	45.98%	49.90%	37.04%
Expected term (in years)	5.00	4.00	4.17
Dividend yield	1.35%	1.67%	2.27%
Risk-free interest rate	2.47%	1.67%	2.91%

Stock option activity for the year ended December 31, 2010 follows:

	Shares	Weighted-average exercise price
Outstanding at beginning of year	6,841,770	$20.17
Granted	1,016,250	$14.85
Exercised	(60,918)	$ 8.61
Cancelled	(10,000)	$13.17
Expired	(77,000)	$19.46
Outstanding at end of year	7,710,102	$19.58
Exercisable at end of year	6,095,018	$20.81

Options outstanding at December 31, 2010 have an aggregate intrinsic value of approximately $30.0 million and a weighted-average remaining contractual term of 5.6 years. Options exercisable at December 31, 2010 have an aggregate intrinsic value of approximately $18.7 million and a weighted-average remaining contractual term of 4.8 years. Additional information with respect to options granted, vested and exercised during the years ended December 31, 2010, 2009 and 2008 follows:

	2010	2009	2008
Weighted-average grant date fair value of stock options granted (per share)	$ 5.69	$ 4.71	$ 7.20
Grant date fair value of stock options vested during the year (in thousands)	$5,553	$6,973	$ 6,761
Aggregate intrinsic value of stock options exercised (in thousands)	$ 523	$ 510	$45,240

As of December 31, 2010, options to purchase 1,615,084 shares were outstanding and not vested. All of these non-vested options are expected to ultimately vest. Additional information as of December 31, 2010 with respect to these non-vested options follows:

Aggregate intrinsic value	$11.3 million
Weighted-average remaining contractual term	8.88 years
Weighted-average remaining expected term	3.56 years
Weighted-average remaining vesting period	1.88 years
Unrecognized compensation cost	$7.1 million

Restricted Stock — For all restricted stock awards to date, shares of common stock were issued when the awards were made. 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 shares of restricted stock. 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, 2010 follows:

	Shares	Weighted-average Grant Date Fair Value
Non-vested restricted stock outstanding at beginning of year	1,231,901	$21.67
Granted	699,825	$14.68
Vested	(758,394)	$23.48
Forfeited	(59,281)	$21.63
Non-vested restricted stock outstanding at end of year	1,114,051	$16.05

As of December 31, 2010, approximately 976,000 shares of non-vested restricted stock outstanding are expected to vest. Additional information as of December 31, 2010 with respect to these non-vested shares follows:

Aggregate intrinsic value	$21.0 million
Weighted-average remaining vesting period	1.90 years
Unrecognized compensation cost	$12.2 million

Restricted Stock Units — For all restricted stock unit awards made to date, shares of common stock are not issued until the units vest. Restricted stock units 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 for the year ended December 31, 2010 follows:

	Shares	Weighted Average Grant Date Fair Value
Non-vested restricted stock units outstanding at beginning of year	16,167	$26.81
Granted	9,000	$13.81
Vested	(7,333)	$28.08
Forfeited	—	$ —
Non-vested restricted stock units outstanding at end of year	17,834	$19.73

Performance Unit Awards. On April 28, 2009, the Company granted cash-settled performance unit awards to certain executive officers (the "2009 Performance Units"). The 2009 Performance Units provide for those executive officers to receive a cash payment upon the achievement of certain performance goals established by the Company during a specified period. The performance period for the 2009 Performance Units is the period from April 1, 2009 through March 31, 2012, but can extend through March 31, 2014 in certain circumstances. The performance goals for the 2009 Performance Units are tied to the Company's total shareholder return for the performance period as compared to total shareholder return for a peer group determined by the Compensation Committee of the Board of Directors. These goals are considered to be market conditions under the relevant accounting standards and the market conditions are factored into the determination of the fair value of the performance units. Generally, the recipients will receive a base payment if the Company's total shareholder return is positive and, when compared to the peer group, is at or above the 25th percentile but less than the 50th percentile; two times the base if at or above the 50th percentile but less than the 75th percentile, and four times the base if at the 75th percentile or higher. The total base amount with respect to the 2009 Performance Units is approximately $1.7 million. Because the 2009 Performance Units are to be settled in cash at the end of the performance period, they are accounted for as liability awards and the Company's pro-rated obligation is measured at estimated fair value at the end of each reporting period using a Monte Carlo simulation model. As of December 31, 2010 this pro-rated obligation was approximately $2.3 million and is included in the caption "other" in the liabilities section of the consolidated balance sheet. Compensation expense associated with the 2009 Performance Units was approximately $1.5 million and $859,000 for the years ended December 31,2010 and 2009, respectively.

On April 27, 2010, the Company granted stock-settled performance unit awards to certain executive officers (the "2010 Performance Units"). The 2010 Performance Units provide for those executive officers to receive a grant of shares of stock upon the achievement of certain performance goals established by the Company during a specified period. The performance period for the 2010 Performance Units is the period from April 1, 2010 through March 31, 2013, but can extend through March 31, 2015 in certain circumstances. The performance goals for the 2010 Performance Units are tied to the Company's total shareholder return for the performance period as compared to total shareholder return for a peer group determined by the Compensation Committee of the Board of Directors. These goals are considered to be market conditions under the relevant accounting standards and the market conditions are factored into the determination of the fair value of the performance units. Generally, the recipients will receive a base number of shares if the Company's total shareholder return is positive and, when compared to the peer group, is at or above the 25th percentile but less than the 50th percentile, two times the base if at or above the 50th percentile but less than the 75th percentile, and four times the base if at the 75th percentile or higher. The grant of shares when achievement is between the 25th and 75th percentile will be determined on a pro-rata basis. The total base number of shares with respect to the 2010 Performance Units is 89,375 shares. Because the 2010 Performance Units are stock-settled awards, they are accounted for as equity awards and measured at fair value on the date of grant. The fair value of the 2010 Performance Units as of the date of grant was approximately $3.1 million using a Monte Carlo simulation model. This amount will be recognized on a straight-line basis over the performance period. Compensation expense associated with the 2010 Performance Units was approximately $779,000 for the year ended December 31, 2010.

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.

12. Leases

The Company incurred rent expense of $18.1 million, $11.9 million and $31.5 million for the years 2010, 2009 and 2008, respectively. Rent expense is primarily related to short-term equipment rentals that are generally passed through to customers. The Company's obligations under non-cancelable operating lease agreements are not material to its operations or cash flows.

13. Income Taxes

Components of the income tax provision applicable to Federal, state and foreign income taxes for the years ended December 31, 2010, 2009 and 2008 are as follows (in thousands):

	2010	2009	2008
Federal income tax expense (benefit):			
Current	$ (77,310)	$(117,493)	$117,367
Deferred	145,198	103,574	57,879
	67,888	(13,919)	175,246
State income tax expense (benefit):			
Current	19	(1,883)	6,475
Deferred	3,246	(1,875)	7,070
	3,265	(3,758)	13,545
Foreign income tax expense (benefit):			
Current	2,657	338	4,256
Deferred	(954)	(256)	443
	1,703	82	4,699
Total income tax expense (benefit):			
Current	(74,634)	(119,038)	128,098
Deferred	147,490	101,443	65,392
Total income tax expense (benefit)	$ 72,856	$ (17,595)	$193,490

The difference between the statutory Federal income tax rate and the effective income tax rate for the years ended December 31, 2010, 2009 and 2008 is summarized as follows:

	2010	2009	2008
Statutory tax rate	35.0%	35.0%	35.0%
State income taxes	1.1	4.7	1.7
Permanent differences	2.3	(5.7)	(1.2)
Other, net	(0.2)	0.1	(0.2)
Effective tax rate	38.2%	34.1%	35.3%

For 2008, the permanent difference indicated above was largely attributable to the Company's Domestic Production Activities Deduction. 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,) and allows a deduction of 6% in both 2008 and 2009 and 9% in 2010 and thereafter on the lesser of qualified production activities income or taxable income. The permanent differences for 2010 and 2009 reflect the recapture of a portion of this deduction due to the planned carryback of the 2010 net operating loss to prior years and the carryback of the 2009 net operating loss to prior years. This recapture resulted in a negative effective rate impact in 2009 due to the Company having a loss before income taxes in that year.

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

	December 31, 2010	Net Change	December 31, 2009	Net Change	December 31, 2008	Net Change	December 31, 2007
Deferred tax assets:							
Current:							
Net operating loss carryforwards	$ —	$ —	$ —	$ —	$ —	$ (374)	$ 374
Workers' compensation allowance	23,290	(1,334)	24,624	(1,360)	25,984	(602)	26,586
Other	18,654	(962)	19,616	(2,735)	22,351	3,287	19,064
	41,944	(2,296)	44,240	(4,095)	48,335	2,311	46,024
Non-current:							
Net operating loss carryforwards	6,465	1,593	4,872	4,872	—	—	—
AMT credit	—	—	—	—	—	(118)	118
Expense associated with employee stock options	11,252	2,123	9,129	2,500	6,629	1,381	5,248
Federal benefit of foreign deferred tax liabilities	—	(9,160)	9,160	(256)	9,416	443	8,973
Federal benefit of state deferred tax liabilities	13,155	3,383	9,772	2,702	7,070	1,643	5,427
Other	16,031	6,546	9,485	4,120	5,365	614	4,751
	46,903	4,485	42,418	13,938	28,480	3,963	24,517
Total deferred tax assets	88,847	2,189	86,658	9,843	76,815	6,274	70,541
Deferred tax liabilities:							
Current:							
Other	(15,129)	(3,766)	(11,363)	1,044	(12,407)	(1,753)	(10,654)
Non-current:							
Property and equipment basis difference	(546,655)	(133,542)	(413,113)	(110,786)	(302,327)	(70,362)	(231,965)
Other	(11,670)	(709)	(10,961)	(7,091)	(3,870)	8,172	(12,042)
	(558,325)	(134,251)	(424,074)	(117,877)	(306,197)	(62,190)	(244,007)
Total deferred tax liabilities	(573,454)	(138,017)	(435,437)	(116,833)	(318,604)	(63,943)	(254,661)
Net deferred tax liability	$(484,607)	$(135,828)	$(348,779)	$(106,990)	$(241,789)	$(57,669)	$(184,120)

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, 2010 and 2009 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 considered necessary.

Other deferred tax assets consist primarily of the tax effect of various allowance accounts and tax-deferred expenses expected to generate future tax benefit of approximately $35 million. Other deferred tax liabilities consist primarily of the tax effect of receivables from insurance companies and tax-deferred income not yet recognized for tax purposes.

For income tax purposes, the Company generated approximately $221 million of Federal net operating losses and approximately $71.3 million of state net operating losses during the year ended December 31, 2010. Of these amounts, approximately $257 million will be carried back to prior years, and the remaining balance can be carried forward to future years. Net operating losses that can be carried forward, if unused, are scheduled to expire as follows: 2014 — $9 million; 2015 — $5 million; 2019 — $12 million; 2029 — $57 million and 2030 - $18 million.

As of December 31, 2010, the Company had no unrecognized tax benefits. The Company has established a policy to account for interest and penalties related to uncertain income tax positions as operating expenses. As of December 31, 2010, the tax years ended December 31, 2007 through December 31, 2009 are open for examination by U.S. taxing authorities. As of December 31, 2010, the tax years ended December 31, 2006 through December 31, 2009 are open for examination by Canadian taxing authorities.

On January 1, 2010, the Company converted its Canadian operations from a Canadian branch to a controlled foreign corporation for Federal income tax purposes. Because the statutory tax rates in Canada are lower than those in the United States, this transaction triggered a $5.1 million reduction in deferred tax liabilities, which is being amortized as a reduction to deferred income tax expense over the weighted average remaining useful life of the Canadian assets.

As a result of the above conversion, the Company's Canadian assets are no longer subject to United States taxation, provided that the related unremitted earnings are permanently reinvested in Canada. Effective January 1, 2010, the Company has elected to permanently reinvest these unremitted earnings in Canada, and intends to do so for the foreseeable future. As a result, no deferred United States Federal or state income taxes have been provided on such unremitted foreign earnings, which totaled approximately $6.3 million as of December 31, 2010.

14. Employee Benefits

The Company maintains a 401(k) plan for all eligible employees. The Company's operating results include expenses of approximately $3.1 million in 2010, $2.8 million in 2009 and $4.5 million in 2008 for the Company's cash contributions to the plan.

15. Business Segments

The Company's revenues, operating profits and identifiable assets are primarily attributable to three business segments: (i) contract drilling of oil and natural gas wells, (ii) pressure pumping services and (iii) the investment, on a working interest basis, in oil and natural gas properties. Each of these segments represents a distinct type of business. These segments have separate management teams which report to the Company's chief operating decision maker. The results of operations in these segments are regularly reviewed by the chief operating decision maker for purposes of determining resource allocation and assessing performance. As discussed in Note 2, in January 2010 the Company exited the drilling and completion fluids services business which previously was reported as a business segment. Operating results for that business for the years ended December 31, 2010, 2009 and 2008 are presented as discontinued operations in the consolidated statements of operations. Also included in discontinued operations for the year ended December 31, 2010 are the operating results for an electric wireline business that was acquired on October 1, 2010 and sold in January 2011.

Contract Drilling — The Company markets its contract drilling services to major and independent oil and natural gas operators. As of December 31, 2010, the Company had 356 marketable land-based drilling rigs, of which 73 of the drilling rigs were based in west Texas and southeastern New Mexico; 97 in north central and east Texas, northern Louisiana and Mississippi; 58 in the Rocky Mountain region (Colorado, Utah, Wyoming, Montana and North Dakota); 51 in south Texas and southern Louisiana; 32 in the Texas panhandle, Oklahoma and Arkansas; 25 in the Appalachian Basin and 20 in western Canada.

For the years ended December 31, 2010, 2009 and 2008, contract drilling revenue earned in Canada was $65.7 million, $45.4 million and $88.5 million, respectively. Additionally, long-lived assets within the contract drilling segment located in Canada totalled $70.7 million and $69.2 million as of December 31, 2010 and 2009, respectively.

Pressure Pumping — The Company provides pressure pumping services to oil and natural gas operators primarily in Texas and the Appalachian Basin. Pressure pumping services are primarily 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.

Oil and Natural Gas — The Company owns and invests in oil and natural gas assets as a working interest owner. The Company's oil and natural gas interests are located primarily in Texas and New Mexico.

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

	Years Ended December 31,		
	2010	2009	2008
Revenues:			
Contract drilling	$1,085,722	$ 600,423	$1,808,600
Pressure pumping	350,608	161,441	217,494
Oil and natural gas	30,425	21,218	42,360
Total segment revenues	1,466,755	783,082	2,068,454
Elimination of intercompany revenues(a)	(3,824)	(1,136)	(4,574)
Total revenues	$1,462,931	$ 781,946	$2,063,880
Income (loss) from continuing operations before income taxes:			
Contract drilling	$ 140,483	$ (11,219)	$ 520,636
Pressure pumping	62,194	1,017	42,019
Oil and natural gas	12,455	950	13,711
	215,132	(9,252)	576,366
Corporate and other	(37,019)	(35,577)	(34,596)
Net (loss) gain on asset disposals(b)	22,812	(3,385)	4,163
Interest income	1,674	381	1,553
Interest expense	(12,772)	(4,148)	(630)
Other	927	426	502
Income (loss) from continuing operations before income taxes	$ 190,754	$ (51,555)	$ 547,358
Identifiable assets:			
Contract drilling	$2,678,250	$2,129,567	$2,255,421
Pressure pumping	533,597	213,094	210,805
Oil and natural gas	36,508	25,355	31,760
Corporate and other(c)	174,676	294,136	214,831
Total assets	$3,423,031	$2,662,152	$2,712,817
Depreciation, depletion, amortization and impairment:			
Contract drilling	$ 280,458	$ 248,424	$ 239,700
Pressure pumping	40,724	27,589	19,600
Oil and natural gas	10,950	12,927	15,856
Corporate and other	1,361	907	834
Total depreciation, depletion, amortization and impairment	$ 333,493	$ 289,847	$ 275,990

	Years Ended December 31,		
	2010	2009	2008
Capital expenditures:			
Contract drilling	$ 655,550	$ 395,376	$ 360,645
Pressure pumping	51,064	43,144	61,289
Oil and natural gas	23,067	7,341	22,981
Corporate and other	8,409	6,785	511
Total capital expenditures	$ 738,090	$ 452,646	$ 445,426

(a) Includes contract drilling intercompany revenues related to drilling services provided to the oil and natural gas exploration and production segment.

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

(c) Corporate and other assets primarily include identifiable assets associated with assets held for sale as well as cash on hand, income taxes receivable and certain deferred Federal income tax assets.

16. 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, 2010 and 2009, the Company's demand deposits and temporary cash investments consisted of the following (in thousands):

	2010	2009
Deposits in FDIC and SIPC-insured institutions under insurance limits	$ 1,523	$ 20,543
Deposits in FDIC and SIPC-insured institutions over insurance limits	51,625	47,376
Deposits in foreign banks	11,533	4,383
	64,681	72,302
Less outstanding checks and other reconciling items	(37,069)	(22,425)
Cash and cash equivalents	$ 27,612	$ 49,877

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, 2010, 2009 or 2008. The Company recorded a provision for bad debts for 2010, 2009 and 2008 of $(2.0) million, $3.8 million and $4.4 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. The carrying value of the balance outstanding under the term loan facility at December 31, 2010 approximates fair value as it has a floating interest rate that adjusts at each quarterly interest payment date. The fair value of the 4.97% Series A Senior Notes at December 31, 2010 was approximately $290 million.

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

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2009				
Operating revenues	$268,209	$140,497	$159,671	$213,569
Operating income (loss)	25,154	(25,855)	(24,619)	(22,894)
Income (loss) from continuing operations, net of income taxes	15,835	(16,891)	(16,814)	(16,090)
Income (loss) from discontinued operations, net of income taxes	368	(852)	(1,766)	(2,080)
Net income (loss)	16,203	(17,743)	(18,580)	(18,170)
Basic income (loss) per common share:				
From continuing operations	$ 0.10	$ (0.11)	$ (0.11)	$ (0.11)
From discontinued operations	$ 0.00	$ (0.01)	$ (0.01)	$ (0.01)
Net income	$ 0.11	$ (0.12)	$ (0.12)	$ (0.12)
Diluted income (loss) per common share:				
From continuing operations	$ 0.10	$ (0.11)	$ (0.11)	$ (0.11)
From discontinued operations	$ 0.00	$ (0.01)	$ (0.01)	$ (0.01)
Net income	$ 0.11	$ (0.12)	$ (0.12)	$ (0.12)
2010				
Operating revenues	$271,598	$306,992	$378,663	$505,678
Operating income	7,831	45,757	52,509	94,828
Income (loss) from continuing operations, net of income taxes	4,186	29,528	29,374	54,810
Loss from discontinued operations, net of income taxes	—	—	—	(956)
Net income	4,186	29,528	29,374	53,854
Basic income (loss) per common share:				
From continuing operations	$ 0.03	$ 0.19	$ 0.19	$ 0.36
From discontinued operations	$ 0.00	$ 0.00	$ 0.00	$ (0.01)
Net income	$ 0.03	$ 0.19	$ 0.19	$ 0.35
Diluted income (loss) per common share:				
From continuing operations	$ 0.03	$ 0.19	$ 0.19	$ 0.35
From discontinued operations	$ 0.00	$ 0.00	$ 0.00	$ (0.01)
Net income	$ 0.03	$ 0.19	$ 0.19	$ 0.35

As discussed in Note 2, the Company exited the drilling and completion fluids services business in January 2010 and sold a recently acquired wireline business in January 2011. The results of operations related to those businesses have been reclassified and presented as discontinued operations in the quarterly financial information above.

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, 2010				
Deducted from asset accounts:				
Allowance for doubtful accounts	$10,911	$(2,000)	$3,797	$ 5,114
Year Ended December 31, 2009				
Deducted from asset accounts:				
Allowance for doubtful accounts	$ 9,330	$ 4,700	$3,119	$10,911
Year Ended December 31, 2008				
Deducted from asset accounts:				
Allowance for doubtful accounts	$10,014	$ 4,350	$5,034	$ 9,330

(1) Consists of uncollectible accounts written off.

SIGNATURES

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

PATTERSON-UTI ENERGY, INC.

By: /s/ Douglas J. Wall

Douglas J. Wall
President and Chief Executive Officer

Date: February 14, 2011

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 14, 2011.

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

CORPORATE INFORMATION

DIRECTORS

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

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

Charles O. Buckner
Retired Partner,
Ernst & Young LLP

Curtis W. Huff
Managing Partner
Intervale Capital LLC

Terry H. Hunt
Energy Consultant

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

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

CORPORATE OFFICERS

Mark S. Siegel
Chairman

Douglas J. Wall
President and
Chief Executive Officer

Kenneth N. Berns
Senior Vice President

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

Seth D. Wexler
General Counsel
and Secretary

Gregory W. Pipkin
Chief Accounting Officer
and Assistant Secretary

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COMMON STOCK

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INDEPENDENT AUDITOR

PricewaterhouseCoopers LLP

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