HELMERICH & PAYNE INC
Form 10-K
November 27, 2013

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Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended September 30, 2013

OR

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

For the transition period from to
Commission file number 1-4221

HELMERICH & PAYNE, INC.

(Exact Name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**73-0679879** (I.R.S. Employer Identification No.)
1437 S. Boulder Ave., Suite 1400, Tulsa, Oklahoma (Address of Principal Executive Offices)	**74119-3623** (Zip Code)

(918) 742-5531
Registrant's telephone number, including area code

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock ($0.10 par value)	New York Stock Exchange
Preferred Stock Purchase Rights	New York Stock Exchange

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 o No ý

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

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 ý No o

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, 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 ý No o

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

Indicate by check mark whether the Registrant is 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.

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

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

At March 28, 2013, the aggregate market value of the voting stock held by non-affiliates was $6,260,548,651.

Number of shares of common stock outstanding at November 15, 2013: 107,142,985.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's 2014 Proxy Statement for the Annual Meeting of Stockholders to be held on March 5, 2014 are incorporated by reference into Part III of this Form 10-K. The 2014 Proxy Statement will be filed with the U.S. Securities and Exchange Commission within 120 days after the end of the fiscal year to which this Form 10-K relates.

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DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K ("Form 10-K") includes "forward-looking statements" within the meaning of the Securities Act of 1933, as amended, and the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included in this Form 10-K, including, without limitation, statements regarding the Registrant's future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements. In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as "may", "will", "expect", "intend", "estimate", "anticipate", "believe", or "continue" or the negative thereof or similar terminology. Although the Registrant believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to be correct. Important factors that could cause actual results to differ materially from the Registrant's expectations or results discussed in the forward-looking statements are disclosed in this Form 10-K under Item 1A "Risk Factors", as well as in Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations." All subsequent written and oral forward-looking statements attributable to the Registrant, or persons acting on its behalf, are expressly qualified in their entirety by such cautionary statements. The Registrant assumes no duty to update or revise its forward-looking statements based on changes in internal estimates, expectations or otherwise, except as required by law.

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PART I

Item 1. BUSINESS

Helmerich & Payne, Inc. (hereafter referred to as the "Company", "we", "us" or "our"), was incorporated under the laws of the State of Delaware on February 3, 1940, and is successor to a business originally organized in 1920. We are primarily engaged in contract drilling of oil and gas wells for others and this business accounts for almost all of our operating revenues.

Our contract drilling business is composed of three reportable business segments: U.S. Land, Offshore and International Land. During fiscal 2013, our U.S. Land operations drilled primarily in Oklahoma, California, Texas, Wyoming, Colorado, Louisiana, Pennsylvania, Ohio, Utah, Arkansas, New Mexico, Montana, North Dakota, West Virginia and Nevada. Offshore operations were conducted in the Gulf of Mexico, and offshore of California and Equatorial Guinea. Our International Land segment operated in six international locations during fiscal 2013: Ecuador, Colombia, Argentina, Tunisia, Bahrain and United Arab Emirates ("UAE").

We are also engaged in the ownership, development and operation of commercial real estate and the research and development of rotary steerable technology. Each of the businesses operates independently of the others through wholly-owned subsidiaries. This operating decentralization is balanced by centralized finance and legal organizations.

Our real estate investments located exclusively within Tulsa, Oklahoma, include a shopping center containing approximately 441,000 leasable square feet, multi-tenant industrial warehouse properties containing approximately one million leasable square feet and approximately 210 acres of undeveloped real estate.

Our subsidiary, TerraVici Drilling Solutions, Inc. ("TerraVici"), is developing patented rotary steerable technology to enhance horizontal and directional drilling operations. We acquired TerraVici to primarily complement our existing drilling rig technology as well as to potentially offer directional drilling services to third parties. By combining this new technology with our existing capabilities, we expect to improve drilling productivity and reduce total well cost to the customer.

On June 30, 2010, the Venezuelan government seized 11 rigs owned by our Venezuelan subsidiary and associated real and personal property. We have sued the Bolivarian Republic of Venezuela and related governmental entities for damages sustained as a result of the seizure of our Venezuelan drilling business. (For further information, see Item 3 "Legal Proceedings"). Our financial statements have been prepared with the net assets, results of operations, and cash flows of the Venezuelan operations presented as discontinued operations. The operations from our Venezuelan subsidiary were previously an operating segment within our International Land segment.

CONTRACT DRILLING

General

We believe that we are one of the major land and offshore platform drilling contractors in the western hemisphere. Operating principally in North and South America, we specialize in shallow to deep drilling in oil and gas producing basins of the United States and in drilling for oil and gas in international locations. In the United States, we draw our customers primarily from the major oil companies and the larger independent oil companies. In South America, our current customers include major international oil companies.

In fiscal 2013, we received approximately 61 percent of our consolidated operating revenues from our ten largest contract drilling customers. BHP Billiton, Devon Energy Production Co. LP and Occidental Oil and Gas Corporation (respectively, "BHP", "Devon" and "Oxy"), including their affiliates, are our three largest contract drilling customers. We perform drilling services for BHP and

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Devon in U.S. land operations and Oxy on a world-wide basis. Revenues from drilling services performed for BHP, Devon and Oxy in fiscal 2013 accounted for approximately 11 percent, 10 percent and 10 percent, respectively, of our consolidated operating revenues for the same period.

Rigs, Equipment and Facilities

We provide drilling rigs, equipment, personnel and camps on a contract basis. These services are provided so that our customers may explore for and develop oil and gas from onshore areas and from fixed platforms, tension-leg platforms and spars in offshore areas. Each of the drilling rigs consists of engines, drawworks, a mast, pumps, blowout preventers, a drill string and related equipment. The intended well depth and the drilling site conditions are the principal factors that determine the size and type of rig most suitable for a particular drilling job. A land drilling rig may be moved from location to location without modification to the rig. A platform rig is specifically designed to perform drilling operations upon a particular platform. While a platform rig may be moved from its original platform, significant expense is incurred to modify a platform rig for operation on each subsequent platform. In addition to traditional platform rigs, we operate self-moving platform drilling rigs and drilling rigs to be used on tension-leg platforms and spars. The self-moving rig is designed to be moved without the use of expensive derrick barges. The tension-leg platforms and spars allow drilling operations to be conducted in much deeper water than traditional fixed platforms.

Mechanical rigs rely on belts, pulleys and other mechanical devices to control drilling speed and other rig processes. As such, mechanical rigs are not highly efficient or precise in their operation. In contrast to mechanical rigs, SCR rigs rely on direct current for power. This enables motor speed to be controlled by changing electrical voltage. Compared to mechanical rigs, SCR rigs operate with greater efficiency, more power and better control. AC rigs provide for even greater efficiency and flexibility than what can be achieved with mechanical or SCR rigs. AC rigs use a variable frequency drive that allows motor speed to be manipulated via changes to electrical frequency. The variable frequency drive permits greater control of motor speed for more precision. Among other attributes, AC rigs are electrically more efficient, produce more torque, utilize regenerative braking, have digital controls and AC motors require less maintenance.

During the mid-1990's, we undertook an initiative to use our land and offshore platform drilling experience to develop a new generation of drilling rigs that would be safer, faster-moving and more capable than mechanical rigs. In 1998, we put to work a new generation of highly mobile/depth flexible land drilling rigs (individually the "FlexRig®"). Since the introduction of our FlexRigs, we have focused on designing and building high-performance, high-efficiency rigs to be used exclusively in our contract drilling business. We believed that over time FlexRigs would displace older less capable rigs. With the advent of unconventional shale plays, our AC drive FlexRigs have proven to be particularly well suited for more complex horizontal drilling requirements. The FlexRig has been able to significantly reduce average rig move and drilling times compared to similar depth-rated traditional land rigs. In addition, the FlexRig allows greater depth flexibility and provides greater operating efficiency. The original rigs were designated as FlexRig1 and FlexRig2 rigs and were designed to drill wells with a depth of between 8,000 and 18,000 feet. In 2001, we announced that we would build the next generation of FlexRigs, known as "FlexRig3", which incorporated new drilling technology and new environmental and safety design. This new design included integrated top drive, AC electric drive, hydraulic BOP handling system, hydraulic tubular make-up and break-out system, split crown and traveling blocks and an enlarged drill floor that enables simultaneous crew activities. FlexRig3s were designed to target well depths of between 8,000 and 22,000 feet.

In 2006, we placed into service our first FlexRig4. While FlexRig4s are similar to our FlexRig3s, the FlexRig4s are designed to efficiently drill more shallow depth wells of between 4,000 and 18,000 feet. The FlexRig4 design includes a trailerized version and a skidding version, which incorporate additional environmental and safety design. This design permits the installation of a pipe handling system which allows the rig to be more efficiently operated and eliminates the need for a casing stabber in the mast. While the FlexRig4 trailerized version provides for more efficient well site to well site rig moves, the skidding version allows for drilling of up to 22 wells from a single pad which results in reduced environmental impact. In 2011, we announced the introduction of the FlexRig5 design. The FlexRig5 is suited for long lateral drilling of multiple wells from a single location, which is well suited for unconventional shale reservoirs. The new design preserves the key performance features of FlexRig3 combined with a bi-directional pad drilling system and equipment capacities suitable for wells in excess of 25,000 feet of measured depth.

Industry trends toward more complex drilling have accelerated the retirement of less capable mechanical rigs. Over the past few years our mechanical rigs have been sold as we added new AC drive rigs to our fleet. The retirement of our remaining seven mechanical rigs in fiscal 2011 marked the end of a multi-year evolution in the high-grading of our fleet from mechanical rigs to high-efficiency, high-performance rigs.

Since 1998, we have built and delivered 300 FlexRigs, including 178 FlexRig3s, 88 FlexRig4s, and 17 FlexRig5s. Of the total FlexRigs built through September 30, 2013, 149 have been built in the last five years. As of November 15, 2013, an additional nine new FlexRigs remained under construction.

The effective use of technology is important to the maintenance of our competitive position within the drilling industry. We expect to continue to refine our existing technology and develop new technology in the future.

We assemble new FlexRigs at our gulf coast facility near Houston, Texas. We also have a 123,000 square foot fabrication facility located on approximately 11 acres near Tulsa, Oklahoma. Additionally, we lease a 150,000 square foot industrial facility near Tulsa, Oklahoma, for the purpose of overhauling/repairing rig equipment and associated component parts.

Drilling Contracts

Our drilling contracts are obtained through competitive bidding or as a result of negotiations with customers, and often cover multi-well and multi-year projects. Each drilling rig operates under a separate drilling contract. During fiscal 2013, all drilling services were performed on a "daywork" contract basis, under which we charge a fixed rate per day, with the price determined by the location, depth and complexity of the well to be drilled, operating conditions, the duration of the contract, and the competitive forces of the market. We have previously performed contracts on a combination "footage" and "daywork" basis, under which we charged a fixed rate per foot of hole drilled to a stated depth, usually no deeper than 15,000 feet, and a fixed rate per day for the remainder of the hole. Contracts performed on a "footage" basis involve a greater element of risk to the contractor than do contracts performed on a "daywork" basis. Also, we have previously accepted "turnkey" contracts under which we charge a fixed sum to deliver a hole to a stated depth and agree to furnish services such as testing, coring and casing the hole which are not normally done on a "footage" basis. "Turnkey" contracts entail varying degrees of risk greater than the usual "footage" contract. We have not accepted any "footage" or "turnkey" contracts in over fifteen years. We believe that under current market conditions, "footage" and "turnkey" contract rates do not adequately compensate us for the added risks. The duration of our drilling contracts are "well-to-well" or for a fixed term. "Well-to-well" contracts are cancelable at the option of either party upon the completion of drilling at any one site. Fixed-term contracts generally have a minimum term of at least six months but customarily provide for termination at the election of the customer, with an "early termination payment" to be paid to us if a contract is terminated prior to the expiration of the fixed term. However, under certain limited circumstances such as destruction of a drilling rig, our bankruptcy, sustained unacceptable performance by us or delivery of a rig beyond certain grace and/or liquidated damage periods, no early termination payment would be paid to us.

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Contracts generally contain renewal or extension provisions exercisable at the option of the customer at prices mutually agreeable to us and the customer. In most instances contracts provide for additional payments for mobilization and demobilization.

As of September 30, 2013, we had 176 rigs under fixed-term contracts. While the original duration for these current fixed-term contracts are for six-month to seven-year periods, some fixed-term and well-to-well contracts are expected to be extended for longer periods than the original terms. However, the contracting parties have no legal obligation to extend these contracts.

Backlog

Our contract drilling backlog, being the expected future revenue from executed contracts with original terms in excess of one year, as of September 30, 2013 and 2012 was $2.9 billion and $3.6 billion, respectively. The decrease in backlog at September 30, 2013 from September 30, 2012, is primarily due to expiration of long-term contracts. Approximately 81.7 percent of the total September 30, 2013 backlog is not reasonably expected to be filled in fiscal 2014. A portion of the backlog represents term contracts for new rigs that will be constructed in the future.

The following table sets forth the total backlog by reportable segment as of September 30, 2013 and 2012, and the percentage of the September 30, 2013 backlog not reasonably expected to be filled in fiscal 2014:

Reportable Segment	Total Backlog Revenue 9/30/2013	9/30/2012	Percentage Not Reasonably Expected to be Filled in Fiscal 2014
	(in billions)		
U.S. Land	$ 2.4	$ 3.0	89.1%
Offshore	0.1	0.1	55.6%
International	0.4	0.5	46.9%
	$ 2.9	$ 3.6	

We obtain certain key rig components from a single or limited number of vendors or fabricators. Certain of these vendors or fabricators are thinly capitalized independent companies located on the Texas gulf coast. Therefore, disruptions in rig component deliveries may occur. Accordingly, the actual amount of revenue earned may vary from the backlog reported. For further information, see Item 1A "Risk Factors".

U.S. Land Drilling

At the end of September 2013, 2012, and 2011, we had 302, 282 and 248, respectively, of our land rigs available for work in the United States. The total number of rigs at the end of fiscal 2013 increased by a net of 20 rigs from the end of fiscal 2012. The increase is due to 20 new FlexRigs being completed and placed into service, two new FlexRigs being completed and ready for delivery and two older conventional rigs being removed from service. Our U.S. Land operations contributed approximately 82 percent ($2.8 billion) of our consolidated operating revenues during fiscal 2013, compared with approximately 85 percent ($2.7 billion) of consolidated operating revenues during fiscal 2012 and approximately 83 percent ($2.1 billion) of consolidated operating revenues during fiscal 2011. Rig utilization was approximately 82 percent in fiscal 2013, approximately 89 percent in fiscal 2012 and approximately 86 percent in fiscal 2011. Our fleet of FlexRigs had an average utilization of approximately 87 percent during fiscal 2013, while our conventional rigs had an average utilization of approximately 2 percent. A rig is considered to be utilized when it is operated or being mobilized or demobilized under contract. At the close of fiscal 2013, 246 out of an available 302 land rigs were working.

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Offshore Drilling

Our Offshore operations contributed approximately 7 percent in fiscal year 2013 ($221.9 million) of our consolidated operating revenues compared to approximately 6 percent ($189.1 million) of consolidated operating revenues during fiscal 2012 and 8 percent ($201.4 million) of consolidated operating revenues during fiscal 2011. Rig utilization in fiscal 2013 was approximately 89 percent compared to approximately 79 percent in fiscal 2012 and approximately 77 percent in fiscal 2011. At the end of fiscal 2013, we had eight of our nine offshore platform rigs under contract and continued to work under management contracts for two customer-owned rigs. Revenues from drilling services performed for our largest offshore drilling customer totaled approximately 54 percent of offshore revenues during fiscal 2013.

International Land Drilling

General

Our International Land operations contributed approximately 11 percent ($366.8 million) of our consolidated operating revenues during fiscal 2013, compared with approximately 9 percent ($270.0 million) of consolidated operating revenues during fiscal 2012 and 9 percent ($226.8 million) in fiscal 2011. Rig utilization in fiscal 2013 was 82 percent, 77 percent in fiscal 2012 and 70 percent in fiscal 2011.

Argentina

At the end of fiscal 2013, we had nine rigs in Argentina. Our utilization rate was approximately 62 percent during fiscal 2013, approximately 52 percent during fiscal 2012 and approximately 49 percent during fiscal 2011. Revenues generated by Argentine drilling operations contributed approximately 2 percent in the three fiscal years 2013, 2012 and 2011 of our consolidated operating revenues ($73.2 million, $54.3 million and $44.2 million, respectively). Revenues from drilling services performed for our two largest customers in Argentina totaled approximately 2 percent of consolidated operating revenues and approximately 16 percent of international operating revenues during fiscal 2013. The Argentine drilling contracts are primarily with large international or national oil companies.

Colombia

At the end of fiscal 2013, we had seven rigs in Colombia. Our utilization rate was approximately 82 percent during fiscal 2013, approximately 79 percent during fiscal 2012 and approximately 83 percent during fiscal 2011. Revenues generated by Colombian drilling operations contributed approximately 3 percent in the three fiscal years 2013, 2012 and 2011 of our consolidated operating revenues ($100.1 million, $82.2 million and $74.5 million, respectively). Revenues from drilling services performed for our two largest customers in Colombia totaled approximately 2 percent of consolidated operating revenues and approximately 19 percent of international operating revenues during fiscal 2013. The Colombian drilling contracts are primarily with large international or national oil companies.

Ecuador

At the end of fiscal 2013, we had six rigs in Ecuador. The utilization rate in Ecuador was 95 percent in fiscal 2013, compared to 97 percent in fiscal 2012 and 85 percent in fiscal 2011. Revenues generated by Ecuadorian drilling operations contributed approximately two percent in the three fiscal years 2013, 2012 and 2011 of our consolidated operating revenues ($67.9 million, $56.4 million and $42.6 million, respectively). Revenues from drilling services performed for the largest customer in Ecuador totaled approximately 1 percent of consolidated operating revenues and approximately 10 percent of international operating revenues during fiscal 2013. The Ecuadorian drilling contracts are primarily with large international or national oil companies.

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Other Locations

In addition to our operations discussed above, at the end of fiscal 2013 we had two rigs in Tunisia, three rigs in Bahrain and two rigs in the UAE.

FINANCIAL

Information relating to revenues, total assets and operating income by reportable operating segments may be found on, and is incorporated by reference to, Note 14 "Segment Information" included in Item 8 "Financial Statements and Supplementary Data" of this Form 10-K.

EMPLOYEES

We had 8,715 employees within the United States (15 of which were part-time employees) and 1,618 employees in international operations as of September 30, 2013.

AVAILABLE INFORMATION

Our website is located at www.hpinc.com. Annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports, earnings releases, and financial statements are made available free of charge on the investor relations section of our website as soon as reasonably practicable after we electronically file such materials with, or furnish it to, the SEC. The information contained on our website, or available by hyperlink from our website, is not incorporated into this Form 10-K or other documents we file with, or furnish to, the SEC. Annual reports, quarterly reports, current reports, amendments to those reports, earnings releases, financial statements and our various corporate governance documents are also available free of charge upon written request.

Item 1A. RISK FACTORS

In addition to the risk factors discussed elsewhere in this Form 10-K, we caution that the following "Risk Factors" could have a material adverse effect on our business, financial condition and results of operations.

Our business depends on the level of activity in the oil and natural gas industry, which is significantly impacted by the volatility of oil and natural gas prices and other factors.

Our business depends on the conditions of the land and offshore oil and natural gas industry. Demand for our services depends on oil and natural gas industry exploration and production activity and expenditure levels, which are directly affected by trends in oil and natural gas prices. Oil and natural gas prices, and market expectations regarding potential changes to these prices, significantly affect oil and natural gas industry activity. Higher oil and natural gas prices do not necessarily translate into increased activity because demand for our services is typically driven by our customers' expectations of future commodity prices. Commodity prices have historically been volatile. Oil and natural gas prices are impacted by many factors beyond our control, including:

- the demand for oil and natural gas;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- the worldwide economy;
- expectations about future prices;
- domestic and international tax policies;

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- political and military conflicts in oil producing regions or other geographical areas or acts of terrorism in the U.S. or elsewhere;
- technological advances;
- the development and exploitation of alternative fuels;
- local and international political, economic and weather conditions;
- the ability of The Organization of Petroleum Exporting Countries ("OPEC") to set and maintain production levels and pricing;
- the level of production by OPEC and non-OPEC countries; and
- the environmental and other laws and governmental regulations regarding exploration and development of oil and natural gas reserves.

The level of land and offshore exploration, development and production activity and the price for oil and natural gas is volatile and is likely to continue to be volatile in the future. A decline in the worldwide demand for oil and natural gas or prolonged low oil or natural gas prices in the future would likely result in reduced exploration and development of land and offshore areas and a decline in the demand for our services. Even during periods of high prices for oil and natural gas, companies exploring for oil and gas may cancel or curtail programs, or reduce their levels of capital expenditures for exploration and production for a variety of reasons. These factors could cause our revenues and margins to decline, reduce day rates and utilization of our rigs and limit our future growth prospects. In short, any prolonged reduction in demand for our services could have a material adverse effect on our business, financial condition and results of operations.

Our offshore and land operations are subject to a number of operational risks, including environmental and weather risks, which could expose us to significant losses and damage claims. We are not fully insured against all of these risks and our contractual indemnity provisions may not fully protect us.

Our drilling operations are subject to the many hazards inherent in the business, including inclement weather, blowouts, well fires, loss of well control, pollution, and reservoir damage. These hazards could cause significant environmental damage, personal injury and death, suspension of drilling operations, serious damage or destruction of equipment and property and substantial damage to producing formations and surrounding lands and waters.

Our Offshore drilling operations are also subject to potentially greater environmental liability, including pollution of offshore waters and related negative impact on wildlife and habitat, adverse sea conditions and platform damage or destruction due to collision with aircraft or marine vessels. Our Offshore operations may also be negatively affected by blowouts or uncontrolled release of oil by third parties whose offshore operations are unrelated to our operations. We operate several platform rigs in the Gulf of Mexico. The Gulf of Mexico experiences hurricanes and other extreme weather conditions on a frequent basis, the frequency of which may increase with any climate change. Damage caused by high winds and turbulent seas could potentially curtail operations on such platform rigs for significant periods of time until the damage can be repaired. Moreover, even if our platform rigs are not directly damaged by such storms, we may experience disruptions in operations due to damage to customer platforms and other related facilities in the area.

We have a new-build rig assembly facility located near the Houston, Texas ship channel, and our principal fabricator and other vendors are also located in the gulf coast region. Due to their location, these facilities are exposed to potentially greater hurricane damage.

We have indemnification agreements with many of our customers and we also maintain liability and other forms of insurance. In general, our drilling contracts contain provisions requiring our

customers to indemnify us for, among other things, pollution and reservoir damage. However, our contractual rights to indemnification may be unenforceable or limited due to negligent or willful acts by us, our subcontractors and/or suppliers. Our customers may also dispute, or be unable to meet, their contractual indemnification obligations to us. Accordingly, we may be unable to transfer these risks to our drilling customers by contract or indemnification agreements. Incurring a liability for which we are not fully indemnified or insured could have a material adverse effect on our business, financial condition and results of operations.

With the exception of "named wind storm" risk in the Gulf of Mexico, we insure rigs and related equipment at values that approximate the current replacement cost on the inception date of the policy. However, we self-insure a large deductible as well as a significant portion of the estimated replacement cost of our offshore rigs and our land rigs and equipment. We also carry insurance with varying deductibles and coverage limits with respect to offshore platform rigs and "named wind storm" risk in the Gulf of Mexico.

We have insurance coverage for comprehensive general liability, automobile liability, worker's compensation and employer's liability, and certain other specific risks. Insurance is purchased over deductibles to reduce our exposure to catastrophic events. We retain a significant portion of our expected losses under our worker's compensation, general liability and automobile liability programs. The Company self-insures a number of other risks including loss of earnings and business interruption. We are unable to obtain significant amounts of insurance to cover risks of underground reservoir damage; however, we are generally indemnified under our drilling contracts from this risk.

If a significant accident or other event occurs and is not fully covered by insurance or an enforceable or recoverable indemnity from a customer, it could have a material adverse effect on our business, financial condition and results of operations. Our insurance will not in all situations provide sufficient funds to protect us from all liabilities that could result from our drilling operations. Our coverage includes aggregate policy limits. As a result, we retain the risk for any loss in excess of these limits. No assurance can be given that all or a portion of our coverage will not be cancelled during fiscal 2014, that insurance coverage will continue to be available at rates considered reasonable or that our coverage will respond to a specific loss. Further, we may experience difficulties in collecting from our insurers or our insurers may deny all or a portion of our claims for insurance coverage.

A continuing sluggish global economy may affect our business.

As a result of volatility in oil and natural gas prices and a continuing sluggish global economic environment, we are unable to determine whether our customers will maintain spending on exploration and development drilling or whether customers and/or vendors and suppliers will be able to access financing necessary to sustain their current level of operations, fulfill their commitments and/or fund future operations and obligations. The current global economic environment may impact industry fundamentals and result in reduced demand for drilling rigs. Furthermore, these factors may result in certain of our customers experiencing an inability to pay vendors, including us. These conditions could have a material adverse effect on our business, financial condition and results of operations.

The contract drilling business is highly competitive.

Competition in contract drilling involves such factors as price, rig availability and excess rig capacity in the industry, efficiency, condition and type of equipment, reputation, operating safety, environmental impact, and customer relations. Competition is primarily on a regional basis and may vary significantly by region at any particular time. Land drilling rigs can be readily moved from one region to another in response to changes in levels of activity, and an oversupply of rigs in any region may result, leading to increased price competition.

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Although many contracts for drilling services are awarded based solely on price, we have been successful in establishing long-term relationships with certain customers which have allowed us to secure drilling work even though we may not have been the lowest bidder for such work. We have continued to attempt to differentiate our services based upon our FlexRigs and our engineering design expertise, operational efficiency, safety and environmental awareness. This strategy is less effective when lower demand for drilling services intensifies price competition and makes it more difficult or impossible to compete on any basis other than price. Also, future improvements in operational efficiency and safety by our competitors could negatively affect our ability to differentiate our services.

The loss of one or a number of our large customers could have a material adverse effect on our business, financial condition and results of operations.

In fiscal 2013, we received approximately 61 percent of our consolidated operating revenues from our ten largest contract drilling customers and approximately 31 percent of our consolidated operating revenues from our three largest customers (including their affiliates). We believe that our relationship with all of these customers is good; however, the loss of one or more of our larger customers could have a material adverse effect on our business, financial condition and results of operations.

New technologies may cause our drilling methods and equipment to become less competitive, higher levels of capital expenditures will be necessary to keep pace with the bifurcation of the drilling industry, and growth through the building of new drilling rigs is not assured.

The market for our services is characterized by continual technological developments that have resulted in, and will likely continue to result in, substantial improvements in the functionality and performance of rigs and equipment. Our customers are increasingly demanding the services of newer, higher specification drilling rigs. This results in a bifurcation of the drilling fleet and is evidenced by the higher specification drilling rigs (e.g., AC rigs) generally operating at higher overall utilization levels and day rates than the lower specification drilling rigs (e.g., mechanical or SCR rigs). In addition, a significant number of lower specification rigs are being stacked and/or removed from service. As a result of this bifurcation, a higher level of capital expenditures will be required to maintain and improve existing rigs and equipment and purchase and construct newer, higher specification drilling rigs to meet the increasingly sophisticated needs of our customers.

Since the late 1990's we have increased our drilling rig fleet through new construction. Although we take measures to ensure that we use advanced oil and natural gas drilling technology, changes in technology or improvements in competitors' equipment could make our equipment less competitive. There can be no assurance that we will:

- have sufficient capital resources to build new, technologically advanced drilling rigs;
- successfully integrate additional drilling rigs;
- effectively manage the growth and increased size of our organization and drilling fleet;
- successfully deploy idle, stacked or additional drilling rigs;
- maintain crews necessary to operate additional drilling rigs; or
- successfully improve our financial condition, results of operations, business or prospects as a result of building new drilling rigs.

If we are not successful in building new rigs and equipment or upgrading our existing rigs and equipment in a timely and cost-effective manner, we could lose market share. New technologies, services or standards could render some of our services, drilling rigs or equipment obsolete, which could have a material adverse impact on our business, financial condition and results of operation.

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New legislation and regulatory initiatives relating to hydraulic fracturing could delay or limit the drilling services we provide to customers whose drilling programs could be impacted by such laws.

It is a common practice in our industry for our customers to recover natural gas and oil from shale and other formations through the use of horizontal drilling combined with hydraulic fracturing. Hydraulic fracturing is the process of creating or expanding cracks, or fractures, in formations using water, sand and other additives pumped under high pressure into the formation. The hydraulic fracturing process is typically regulated by state oil and natural gas commissions. Several states have adopted or are considering adopting regulations that could impose more stringent permitting, public disclosure, waste disposal and/or well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In addition to state laws, some local municipalities have adopted or are considering adopting land use restrictions, such as city ordinances, that may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. Additionally, the U.S. Environmental Protection Agency, or EPA, has asserted federal regulatory authority over hydraulic fracturing activities involving diesel fuel under the Safe Drinking Water Act and is completing the process of drafting guidance documents related to this newly asserted regulatory authority. There are also governmental reviews either underway or being proposed that focus on shale and other formation completion and production practices, including hydraulic fracturing. Depending on the outcome of these studies, federal and state legislatures and agencies may seek to further regulate or restrict hydraulic fracturing activities.

We do not engage in any hydraulic fracturing activities. However, any new laws, regulations or permitting requirements regarding hydraulic fracturing could delay or limit the drilling services we provide to customers whose drilling programs could be impacted by new legal requirements. Widespread regulation significantly restricting or prohibiting hydraulic fracturing by our customers could have a material adverse impact on our business, financial condition and results of operation.

Failure to comply with the terms of our plea agreement with the United States Department of Justice may adversely affect our business.

On November 8, 2013, the United States District Court for the Eastern District of Louisiana approved the previously disclosed October 30, 2013 plea agreement between our wholly owned subsidiary, Helmerich & Payne International Drilling Co., and the United States Department of Justice, United States Attorney's Office for the Eastern District of Louisiana ("DOJ"). The court's approval of the plea agreement resolved the DOJ's investigation into certain choke manifold testing irregularities that occurred in 2010 at one of Helmerich & Payne International Drilling Co.'s offshore platform rigs in the Gulf of Mexico. As part of the plea agreement, H&PIDC agreed, during a three-year probationary period, to not commit any further criminal violations and to fulfill the terms of an environmental compliance plan ("ECP") whose purpose is to develop and implement additional training and safety programs Our ability to comply with the terms of the plea agreement is dependent, in part, on our successful implementation of the additional training and safety programs set forth in the ECP. While not anticipated, a failure to comply with the terms of the plea agreement, including the ECP, could result in prosecution and other regulatory sanctions, and could otherwise adversely affect our business. We are also currently engaged in discussions with the Inspector General's office of the Department of Interior regarding the same events that were the subject of the DOJ's investigation. Although we presently believe that the outcome of our discussions will not have a material adverse effect on the Company, we can provide no assurances as to the timing or eventual outcome of these discussions. In addition, we could be exposed to civil litigation arising from the events that were the subject of the DOJ's investigation. Any such litigation may result in financial liability. Refer to Item 3 "Legal Proceedings" and Note 13 "Commitments and Contingencies" included in Item 8 "Financial Statements and Supplementary Data" of this Form 10-K for additional discussion of this subject.

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International uncertainties and local laws could adversely affect our business.

International operations are subject to certain political, economic and other uncertainties not encountered in U.S. operations, including increased risks of social unrest, strikes, terrorism, kidnapping of employees, nationalization, forced negotiation or modification of contracts, expropriation of equipment as well as expropriation of a particular oil company operator's property and drilling rights, taxation policies, foreign exchange restrictions, currency rate fluctuations and general hazards associated with foreign sovereignty over certain areas in which operations are conducted. On June 30, 2010, the Venezuelan government seized 11 rigs and associated real and personal property owned by our Venezuelan subsidiary. In Argentina, general economic conditions have shown improvement and political protests and social disturbances have diminished considerably since the economic crisis of 2001 and 2002. However, the rapid and radical nature of the changes in the Argentine social, political, economic and legal environment over the past several years and the absence of a clear political consensus in favor of any particular set of economic policies have given rise to significant uncertainties about the country's economic and political future. It is currently unclear whether the economic and political instability experienced over the past several years will continue and it is possible that, despite recent economic growth, Argentina may return to a deeper recession, higher inflation and unemployment and greater social unrest. If instability persists, there could be a material adverse effect on our results of operations and financial condition.

There can be no assurance that there will not be changes in local laws, regulations and administrative requirements or the interpretation thereof which could have a material adverse effect on the profitability of our operations or on our ability to continue operations in certain areas. Because of the impact of local laws, our future operations in certain areas may be conducted through entities in which local citizens own interests and through entities (including joint ventures) in which we hold only a minority interest or pursuant to arrangements under which we conduct operations under contract to local entities. While we believe that neither operating through such entities nor pursuant to such arrangements would have a material adverse effect on our operations or revenues, there can be no assurance that we will in all cases be able to structure or restructure our operations to conform to local law (or the administration thereof) on terms we find acceptable.

Although we attempt to minimize the potential impact of such risks by operating in more than one geographical area, during fiscal 2013, approximately 11 percent of our consolidated operating revenues were generated from the international contract drilling business. During fiscal 2013, approximately 66 percent of the international operating revenues were from operations in South America. All of the South American operating revenues were from Argentina, Colombia and Ecuador.

We depend on a limited number of vendors, some of which are thinly capitalized and the loss of any of which could disrupt our operations.

Certain key rig components are either purchased from or fabricated by a single or limited number of vendors, and we have no long-term contracts with many of these vendors. Shortages could occur in these essential components due to an interruption of supply or increased demands in the industry. If we are unable to procure certain of such rig components, we would be required to reduce our rig construction or other operations, which could have a material adverse effect on our business, financial condition and results of operations.

If our principal fabricator, located on the Texas gulf coast, was unable or unwilling to continue fabricating rig components, then we would have to transfer this work to other acceptable fabricators. This transfer could result in significant delay in the completion of new FlexRigs. Any significant interruption in the fabrication of rig components could have a material adverse impact on our business, financial condition and results of operations.

Certain key rig components are obtained from vendors that are, in some cases, thinly capitalized, independent companies that generate significant portions of their business from us or from a small

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group of companies in the energy industry. These vendors may be disproportionately affected by any loss of business, downturn in the energy industry or reduction or unavailability of credit. Therefore, disruptions in rig component delivery may occur, and such disruptions and terminations could have a material adverse effect on our business, financial condition and results of operations.

Our securities portfolio may lose significant value due to a decline in equity prices and other market-related risks, thus impacting our debt ratio and financial strength.

At September 30, 2013, we had a portfolio of securities with a total fair value of approximately $306 million, consisting of Atwood Oceanics, Inc. and Schlumberger, Ltd. These securities are subject to a wide variety of market-related risks that could substantially reduce or increase the fair value of our holdings. The portfolio is recorded at fair value on our balance sheet with changes in unrealized after-tax value reflected in the equity section of our balance sheet. At November 14, 2013, the fair value of the portfolio had increased to approximately $322 million.

Failure to comply with the U.S. Foreign Corrupt Practices Act or foreign anti-bribery legislation, other governmental regulations and environmental laws could adversely affect our business.

The U.S. Foreign Corrupt Practices Act ("FCPA") and similar anti-bribery laws in other jurisdictions, including the United Kingdom Bribery Act 2010, generally prohibit companies and their intermediaries from making improper payments to foreign officials for the purpose of obtaining or retaining business. We operate in many parts of the world that have experienced governmental corruption to some degree and, in certain circumstances, strict compliance with anti-bribery laws may conflict with local customs and practices and impact our business. Although we have programs in place covering compliance with anti-bribery legislation, any failure to comply with the FCPA or other anti-bribery legislation could subject us to civil and criminal penalties or other sanctions, which could have a material adverse impact on our business, financial condition and results of operation. We could also face fines, sanctions and other penalties from authorities in the relevant foreign jurisdictions, including prohibition of our participating in or curtailment of business operations in those jurisdictions and the seizure of drilling rigs or other assets.

Additionally, many aspects of our operations are subject to government regulation, including those relating to drilling practices, pollution, disposal of hazardous substances and oil field waste. The United States and various other countries have environmental regulations which affect drilling operations. The cost of compliance with these laws could be substantial. A failure to comply with these laws and regulations could expose us to substantial civil and criminal penalties. In addition, environmental laws and regulations in the United States 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 drilling rigs, we may be deemed to be a responsible party under these laws and regulations.

We believe that we are in substantial compliance with all legislation and regulations affecting our operations in the drilling of oil and gas wells and in controlling the discharge of wastes. To date, compliance costs have not materially affected our capital expenditures, earnings, or competitive position, although compliance measures may add to the costs of drilling operations. Additional legislation or regulation may reasonably be anticipated, and the effect thereof on our operations cannot be predicted.

Regulation of greenhouse gases and climate change could have a negative impact on our business.

Scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" ("GHGs") and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere and other climatic changes. In response to such studies, the issue of climate change and the effect of GHG emissions, in particular emissions from fossil fuels, is attracting increasing attention worldwide. We are aware of the increasing focus of local, state, national and international regulatory bodies on GHG emissions and climate change issues. The United States Congress may consider legislation to reduce GHG emissions. Although it is not possible at this time to predict whether proposed legislation or regulations will be adopted, any such future laws and regulations could result in increased compliance costs or additional operating restrictions. Any additional costs or operating restrictions associated with legislation or regulations regarding GHG emissions could have a material adverse impact on our business, financial condition and results of operations.

Legal proceedings could have a negative impact on our business.

The nature of our business makes us susceptible to legal proceedings and governmental investigations from time to time. Lawsuits or claims against us could have a material adverse effect on our business, financial condition and results of operations. Any litigation or claims, even if fully indemnified or insured, could negatively affect our reputation among our customers and the public, and make it more difficult for us to compete effectively or obtain adequate insurance in the future.

Our business and results of operations may be adversely affected by foreign currency devaluation.

Contracts for work in foreign countries generally provide for payment in U.S. dollars; however, government-owned petroleum companies may in the future require that a greater proportion of these payments be made in local currencies. Based upon current information, we believe that our exposure to potential losses from currency devaluation in foreign countries is immaterial. However, in the event of future payments in local currencies or an inability to exchange local currencies for U.S. dollars, we may incur currency devaluation losses which could have a material adverse impact on our business, financial condition and results of operations.

Our current backlog of contract drilling revenue may not be ultimately realized as fixed-term contracts may in certain instances be terminated without an early termination payment.

Fixed-term drilling contracts customarily provide for termination at the election of the customer, with an "early termination payment" to be paid to us if a contract is terminated prior to the expiration of the fixed term. However, under certain limited circumstances, such as destruction of a drilling rig, our bankruptcy, sustained unacceptable performance by us or delivery of a rig beyond certain grace and/or liquidated damage periods, no early termination payment would be paid to us. Even if an early termination payment is owed to us, the current global economic environment may affect the customer's ability to pay the early termination payment. We also may not be able to perform under these contracts due to events beyond our control, and our customers may seek to cancel or renegotiate our contracts for various reasons, including those described above. As of September 30, 2013, our contract drilling backlog was approximately $2.9 billion for future revenues under firm commitments. Our inability or the inability of our customers to perform under our or their contractual obligations may have a material adverse impact on our business, financial condition and results of operations.

We may have additional tax liabilities.

We are subject to income taxes in the United States and numerous other jurisdictions. Significant judgment is required in determining our worldwide provision for income taxes. In the ordinary course of our business, there are many transactions and calculations where the ultimate tax determination is uncertain. We are regularly audited by tax authorities. Although we believe our tax estimates are reasonable, the final determination of tax audits and any related litigation could be materially different than what is reflected in income tax provisions and accruals. An audit or litigation could materially affect our financial position, income tax provision, net income, or cash flows in the period or periods challenged. It is also possible that future changes to tax laws (including tax treaties) could impact our ability to realize the tax savings recorded to date.

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Shortages of drilling equipment and supplies could adversely affect our operations.

The contract drilling business is highly cyclical. During periods of increased demand for contract drilling services, delays in delivery and shortages of drilling equipment and supplies can occur. These risks are intensified during periods when the industry experiences significant new drilling rig construction or refurbishment. Any such delays or shortages could have a material adverse effect on our business, financial condition and results of operations.

Reliance on management and competition for experienced personnel may negatively impact our operations or financial results.

We greatly depend on the efforts of our executive officers and other key employees to manage our operations. The loss of members of management could have a material effect on our business. Similarly, we utilize highly skilled personnel in operating and supporting our businesses. In times of high utilization, it can be difficult to retain, and in some cases find, qualified individuals. Although to date our operations have not been materially affected by competition for personnel, an inability to obtain or find a sufficient number of qualified personnel could have a material adverse effect on our business, financial condition and results of operations.

Unionization efforts and labor regulations in certain countries in which we operate could materially increase our costs or limit our flexibility.

Efforts may be made from time to time to unionize portions of our workforce. In addition, we may in the future be subject to strikes or work stoppages and other labor disruptions. Additional unionization efforts, new collective bargaining agreements or work stoppages could materially increase our costs, reduce our revenues or limit our flexibility.

Any future implementation of price controls on oil and natural gas would affect our operations.

Certain groups have asserted efforts to have the United States Congress impose some form of price controls on either oil, natural gas, or both. There is no way at this time to know what results these efforts may have. However, any future limits on the price of oil or natural gas could have a material adverse effect on our business, financial condition and results of operations.

Covenants in our debt agreements restrict our ability to engage in certain activities.

Our debt agreements pertaining to certain long-term unsecured debt and our unsecured revolving credit facility contain various covenants that may in certain instances restrict our ability to, among other things, incur, assume or guarantee additional indebtedness, incur liens, make loans or certain types of investments, sell or otherwise dispose of assets, enter into new lines of business, and merge or consolidate. In addition, our debt agreements also require us to maintain minimum current, funded leverage and interest coverage ratios. Such restrictions may limit our ability to successfully execute our business plans, which may have adverse consequences on our operations.

Improvements in or new discoveries of alternative energy technologies could have a material adverse effect on our financial condition and results of operations.

Since our business depends on the level of activity in the oil and natural gas industry, any improvement in or new discoveries of alternative energy technologies that increase the use of alternative forms of energy and reduce the demand for oil and natural gas could have a material adverse effect on our business, financial condition and results of operations.

Item 1B. UNRESOLVED STAFF COMMENTS

We have received no written comments regarding our periodic or current reports from the staff of the Securities and Exchange Commission that were issued 180 days or more preceding the end of our 2013 fiscal year and that remain unresolved.

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Item 2. PROPERTIES

CONTRACT DRILLING

The following table sets forth certain information concerning our U.S. land and offshore drilling rigs as of September 30, 2013:

Location	Rig	Optimum Depth (Feet)	Rig Type	Drawworks: Horsepower
FLEXRIGS				
TEXAS	164	18,000	SCR (FlexRig1)	1,500
TEXAS	165	18,000	SCR (FlexRig1)	1,500
TEXAS	166	18,000	SCR (FlexRig1)	1,500
TEXAS	167	18,000	SCR (FlexRig1)	1,500
TEXAS	168	18,000	SCR (FlexRig1)	1,500
TEXAS	169	18,000	SCR (FlexRig1)	1,500
NORTH DAKOTA	179	18,000	SCR (FlexRig2)	1,500
NORTH DAKOTA	180	18,000	SCR (FlexRig2)	1,500
TEXAS	181	18,000	SCR (FlexRig2)	1,500
TEXAS	182	18,000	SCR (FlexRig2)	1,500
TEXAS	183	18,000	SCR (FlexRig2)	1,500
TEXAS	184	18,000	SCR (FlexRig2)	1,500
TEXAS	185	18,000	SCR (FlexRig2)	1,500
TEXAS	186	18,000	SCR (FlexRig2)	1,500
TEXAS	187	18,000	SCR (FlexRig2)	1,500
TEXAS	188	18,000	SCR (FlexRig2)	1,500
OKLAHOMA	189	18,000	SCR (FlexRig2)	1,500
TEXAS	210	22,000	AC (FlexRig3)	1,500
TEXAS	211	22,000	AC (FlexRig3)	1,500
NEW MEXICO	212	22,000	AC (FlexRig3)	1,500
TEXAS	213	22,000	AC (FlexRig3)	1,500
NEW MEXICO	214	22,000	AC (FlexRig3)	1,500
WYOMING	215	22,000	AC (FlexRig3)	1,500
TEXAS	216	22,000	AC (FlexRig3)	1,500
TEXAS	217	22,000	AC (FlexRig3)	1,500
TEXAS	218	22,000	AC (FlexRig3)	1,500
OKLAHOMA	219	22,000	AC (FlexRig3)	1,500
TEXAS	220	22,000	AC (FlexRig3)	1,500
TEXAS	221	22,000	AC (FlexRig3)	1,500
TEXAS	222	22,000	AC (FlexRig3)	1,500
NEW MEXICO	223	22,000	AC (FlexRig3)	1,500
TEXAS	224	22,000	AC (FlexRig3)	1,500
PENNSYLVANIA	225	22,000	AC (FlexRig3)	1,500
TEXAS	226	22,000	AC (FlexRig3)	1,500
TEXAS	227	22,000	AC (FlexRig3)	1,500
TEXAS	229	22,000	AC (FlexRig3)	1,500
TEXAS	231	22,000	AC (FlexRig3)	1,500
TEXAS	232	22,000	AC (FlexRig3)	1,500
TEXAS	233	22,000	AC (FlexRig3)	1,500
TEXAS	234	22,000	AC (FlexRig3)	1,500
OKLAHOMA	235	22,000	AC (FlexRig3)	1,500
CALIFORNIA	236	22,000	AC (FlexRig3)	1,500

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Location	Rig	Optimum Depth (Feet)	Rig Type	Drawworks: Horsepower
TEXAS	238	22,000	AC (FlexRig3)	1,500
NORTH DAKOTA	239	22,000	AC (FlexRig3)	1,500
CALIFORNIA	240	22,000	AC (FlexRig3)	1,500
NORTH DAKOTA	241	22,000	AC (FlexRig3)	1,500
TEXAS	243	22,000	AC (FlexRig3)	1,500
TEXAS	244	22,000	AC (FlexRig3)	1,500
TEXAS	245	22,000	AC (FlexRig3)	1,500
TEXAS	246	22,000	AC (FlexRig3)	1,500
TEXAS	247	22,000	AC (FlexRig3)	1,500
TEXAS	248	22,000	AC (FlexRig3)	1,500
TEXAS	249	22,000	AC (FlexRig3)	1,500
OKLAHOMA	250	22,000	AC (FlexRig3)	1,500
OKLAHOMA	251	22,000	AC (FlexRig3)	1,500
TEXAS	252	22,000	AC (FlexRig3)	1,500
TEXAS	253	22,000	AC (FlexRig3)	1,500
TEXAS	254	22,000	AC (FlexRig3)	1,500
NORTH DAKOTA	255	22,000	AC (FlexRig3)	1,500
NORTH DAKOTA	256	22,000	AC (FlexRig3)	1,500
MONTANA	257	22,000	AC (FlexRig3)	1,500
MONTANA	258	22,000	AC (FlexRig3)	1,500
NORTH DAKOTA	259	22,000	AC (FlexRig3)	1,500
TEXAS	260	22,000	AC (FlexRig3)	1,500
CALIFORNIA	261	22,000	AC (FlexRig3)	1,500
CALIFORNIA	262	22,000	AC (FlexRig3)	1,500
TEXAS	263	22,000	AC (FlexRig3)	1,500
TEXAS	264	22,000	AC (FlexRig3)	1,500
TEXAS	265	22,000	AC (FlexRig3)	1,500
TEXAS	266	22,000	AC (FlexRig3)	1,500
TEXAS	267	22,000	AC (FlexRig3)	1,500
OKLAHOMA	268	22,000	AC (FlexRig3)	1,500
TEXAS	269	22,000	AC (FlexRig3)	1,500
WYOMING	271	18,000	AC (FlexRig4)	1,500
MONTANA	272	18,000	AC (FlexRig4)	1,500
COLORADO	273	18,000	AC (FlexRig4)	1,500
TEXAS	274	18,000	AC (FlexRig4)	1,500
WYOMING	275	18,000	AC (FlexRig4)	1,500
NORTH DAKOTA	276	18,000	AC (FlexRig4)	1,500
COLORADO	277	18,000	AC (FlexRig4)	1,500
COLORADO	278	18,000	AC (FlexRig4)	1,500
TEXAS	279	18,000	AC (FlexRig4)	1,500
COLORADO	280	18,000	AC (FlexRig4)	1,500
TEXAS	281	8,000	AC (FlexRig4)	1,150
TEXAS	282	8,000	AC (FlexRig4)	1,150
TEXAS	283	8,000	AC (FlexRig4)	1,150
OHIO	284	18,000	AC (FlexRig4)	1,500
WEST VIRGINIA	285	18,000	AC (FlexRig4)	1,500
NORTH DAKOTA	286	18,000	AC (FlexRig4)	1,500
OHIO	287	18,000	AC (FlexRig4)	1,500
TEXAS	288	18,000	AC (FlexRig4)	1,500

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Location	Rig	Optimum Depth (Feet)	Rig Type	Drawworks: Horsepower
OKLAHOMA	289	18,000	AC (FlexRig4)	1,500
OHIO	290	18,000	AC (FlexRig4)	1,500
NORTH DAKOTA	293	18,000	AC (FlexRig4)	1,500
NORTH DAKOTA	294	18,000	AC (FlexRig4)	1,500
NORTH DAKOTA	295	18,000	AC (FlexRig4)	1,500
TEXAS	296	18,000	AC (FlexRig4)	1,500
OKLAHOMA	297	18,000	AC (FlexRig4)	1,500
UTAH	298	18,000	AC (FlexRig4)	1,500
TEXAS	299	18,000	AC (FlexRig4)	1,500
NEW MEXICO	300	18,000	AC (FlexRig4)	1,500
TEXAS	302	8,000	AC (FlexRig4)	1,150
TEXAS	303	8,000	AC (FlexRig4)	1,150
TEXAS	304	8,000	AC (FlexRig4)	1,150
TEXAS	305	8,000	AC (FlexRig4)	1,150
TEXAS	306	8,000	AC (FlexRig4)	1,150
COLORADO	307	18,000	AC (FlexRig4)	1,500
COLORADO	308	18,000	AC (FlexRig4)	1,500
NORTH DAKOTA	309	18,000	AC (FlexRig4)	1,500
WYOMING	310	18,000	AC (FlexRig4)	1,500
COLORADO	311	18,000	AC (FlexRig4)	1,500
TEXAS	312	18,000	AC (FlexRig4)	1,500
TEXAS	313	18,000	AC (FlexRig4)	1,500
TEXAS	314	18,000	AC (FlexRig4)	1,500
COLORADO	315	18,000	AC (FlexRig4)	1,500
NORTH DAKOTA	316	18,000	AC (FlexRig4)	1,500
NORTH DAKOTA	317	18,000	AC (FlexRig4)	1,500
UTAH	318	18,000	AC (FlexRig4)	1,500
COLORADO	319	18,000	AC (FlexRig4)	1,500
MONTANA	320	18,000	AC (FlexRig4)	1,500
COLORADO	321	18,000	AC (FlexRig4)	1,500
COLORADO	322	18,000	AC (FlexRig4)	1,500
OKLAHOMA	323	18,000	AC (FlexRig4)	1,500
NORTH DAKOTA	324	18,000	AC (FlexRig4)	1,500
NORTH DAKOTA	325	18,000	AC (FlexRig4)	1,500
COLORADO	326	18,000	AC (FlexRig4)	1,500
TEXAS	327	18,000	AC (FlexRig4)	1,500
OKLAHOMA	328	18,000	AC (FlexRig4)	1,500
NORTH DAKOTA	329	18,000	AC (FlexRig4)	1,500
NEVADA	330	18,000	AC (FlexRig4)	1,500
OKLAHOMA	331	18,000	AC (FlexRig4)	1,500
TEXAS	332	18,000	AC (FlexRig4)	1,500
TEXAS	340	8,000	AC (FlexRig4)	1,150
LOUISIANA	341	18,000	AC (FlexRig4)	1,500
TEXAS	342	18,000	AC (FlexRig4)	1,500
COLORADO	343	18,000	AC (FlexRig4)	1,500
TEXAS	344	8,000	AC (FlexRig4)	1,150
TEXAS	345	8,000	AC (FlexRig4)	1,150
TEXAS	346	8,000	AC (FlexRig4)	1,150
TEXAS	347	8,000	AC (FlexRig4)	1,150

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Location	Rig	Optimum Depth (Feet)	Rig Type	Drawworks: Horsepower
TEXAS	348	8,000	AC (FlexRig4)	1,150
TEXAS	349	8,000	AC (FlexRig4)	1,150
TEXAS	351	8,000	AC (FlexRig4)	1,150
TEXAS	352	8,000	AC (FlexRig4)	1,150
NORTH DAKOTA	353	18,000	AC (FlexRig4)	1,500
PENNSYLVANIA	354	18,000	AC (FlexRig4)	1,500
TEXAS	355	8,000	AC (FlexRig4)	1,150
NEW MEXICO	356	8,000	AC (FlexRig4)	1,150
TEXAS	360	8,000	AC (FlexRig4)	1,150
TEXAS	361	8,000	AC (FlexRig4)	1,150
TEXAS	362	8,000	AC (FlexRig4)	1,150
TEXAS	370	22,000	AC (FlexRig3)	1,500
PENNSYLVANIA	371	22,000	AC (FlexRig3)	1,500
TEXAS	372	22,000	AC (FlexRig3)	1,500
TEXAS	373	22,000	AC (FlexRig3)	1,500
OKLAHOMA	374	22,000	AC (FlexRig3)	1,500
OKLAHOMA	375	22,000	AC (FlexRig3)	1,500
OKLAHOMA	376	22,000	AC (FlexRig3)	1,500
OKLAHOMA	377	22,000	AC (FlexRig3)	1,500
OKLAHOMA	378	22,000	AC (FlexRig3)	1,500
OKLAHOMA	379	22,000	AC (FlexRig3)	1,500
CALIFORNIA	380	22,000	AC (FlexRig3)	1,500
CALIFORNIA	381	22,000	AC (FlexRig3)	1,500
TEXAS	382	22,000	AC (FlexRig3)	1,500
TEXAS	383	22,000	AC (FlexRig3)	1,500
TEXAS	384	22,000	AC (FlexRig3)	1,500
OHIO	385	22,000	AC (FlexRig3)	1,500
NORTH DAKOTA	386	22,000	AC (FlexRig3)	1,500
TEXAS	387	22,000	AC (FlexRig3)	1,500
TEXAS	388	22,000	AC (FlexRig3)	1,500
TEXAS	389	22,000	AC (FlexRig3)	1,500
TEXAS	390	22,000	AC (FlexRig3)	1,500
NEW MEXICO	391	22,000	AC (FlexRig3)	1,500
NORTH DAKOTA	392	22,000	AC (FlexRig3)	1,500
TEXAS	393	22,000	AC (FlexRig3)	1,500
NEW MEXICO	394	22,000	AC (FlexRig3)	1,500
TEXAS	395	22,000	AC (FlexRig3)	1,500
TEXAS	396	22,000	AC (FlexRig3)	1,500
TEXAS	397	22,000	AC (FlexRig3)	1,500
TEXAS	398	22,000	AC (FlexRig3)	1,500
TEXAS	399	22,000	AC (FlexRig3)	1,500
TEXAS	415	22,000	AC (FlexRig3)	1,500
NEW MEXICO	416	22,000	AC (FlexRig3)	1,500
TEXAS	417	22,000	AC (FlexRig3)	1,500
OKLAHOMA	418	22,000	AC (FlexRig3)	1,500
OKLAHOMA	419	22,000	AC (FlexRig3)	1,500
TEXAS	420	22,000	AC (FlexRig3)	1,500
TEXAS	421	22,000	AC (FlexRig3)	1,500
TEXAS	422	22,000	AC (FlexRig3)	1,500

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Location	Rig	Optimum Depth (Feet)	Rig Type	Drawworks: Horsepower
TEXAS	423	22,000	AC (FlexRig3)	1,500
CALIFORNIA	424	22,000	AC (FlexRig3)	1,500
OKLAHOMA	425	22,000	AC (FlexRig3)	1,500
CALIFORNIA	426	22,000	AC (FlexRig3)	1,500
OKLAHOMA	427	22,000	AC (FlexRig3)	1,500
TEXAS	428	22,000	AC (FlexRig3)	1,500
TEXAS	429	22,000	AC (FlexRig3)	1,500
TEXAS	430	22,000	AC (FlexRig3)	1,500
TEXAS	431	22,000	AC (FlexRig3)	1,500
TEXAS	432	22,000	AC (FlexRig3)	1,500
TEXAS	433	22,000	AC (FlexRig3)	1,500
TEXAS	434	22,000	AC (FlexRig3)	1,500
OKLAHOMA	435	22,000	AC (FlexRig3)	1,500
TEXAS	436	22,000	AC (FlexRig3)	1,500
TEXAS	437	22,000	AC (FlexRig3)	1,500
NORTH DAKOTA	438	22,000	AC (FlexRig3)	1,500
TEXAS	439	22,000	AC (FlexRig3)	1,500
CALIFORNIA	440	22,000	AC (FlexRig3)	1,500
TEXAS	441	22,000	AC (FlexRig3)	1,500
TEXAS	442	22,000	AC (FlexRig3)	1,500
TEXAS	443	22,000	AC (FlexRig3)	1,500
CALIFORNIA	444	22,000	AC (FlexRig3)	1,500
TEXAS	445	22,000	AC (FlexRig3)	1,500
NORTH DAKOTA	446	22,000	AC (FlexRig3)	1,500
OKLAHOMA	447	22,000	AC (FlexRig3)	1,500
NORTH DAKOTA	448	22,000	AC (FlexRig3)	1,500
NORTH DAKOTA	449	22,000	AC (FlexRig3)	1,500
OKLAHOMA	450	22,000	AC (FlexRig3)	1,500
TEXAS	451	22,000	AC (FlexRig3)	1,500
TEXAS	452	22,000	AC (FlexRig3)	1,500
TEXAS	453	22,000	AC (FlexRig3)	1,500
NORTH DAKOTA	454	22,000	AC (FlexRig3)	1,500
TEXAS	455	22,000	AC (FlexRig3)	1,500
NORTH DAKOTA	456	22,000	AC (FlexRig3)	1,500
NORTH DAKOTA	457	22,000	AC (FlexRig3)	1,500
TEXAS	458	22,000	AC (FlexRig3)	1,500
TEXAS	459	22,000	AC (FlexRig3)	1,500
TEXAS	460	22,000	AC (FlexRig3)	1,500
TEXAS	461	22,000	AC (FlexRig3)	1,500
TEXAS	462	22,000	AC (FlexRig3)	1,500
TEXAS	463	22,000	AC (FlexRig3)	1,500
TEXAS	464	22,000	AC (FlexRig3)	1,500
OKLAHOMA	465	22,000	AC (FlexRig3)	1,500
TEXAS	466	22,000	AC (FlexRig3)	1,500
TEXAS	467	22,000	AC (FlexRig3)	1,500
TEXAS	468	22,000	AC (FlexRig3)	1,500
TEXAS	469	22,000	AC (FlexRig3)	1,500
TEXAS	470	22,000	AC (FlexRig3)	1,500
NORTH DAKOTA	471	22,000	AC (FlexRig3)	1,500

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Location	Rig	Optimum Depth (Feet)	Rig Type	Drawworks: Horsepower
TEXAS	472	22,000	AC (FlexRig3)	1,500
TEXAS	473	22,000	AC (FlexRig3)	1,500
NEW MEXICO	474	22,000	AC (FlexRig3)	1,500
TEXAS	475	22,000	AC (FlexRig3)	1,500
NEW MEXICO	477	22,000	AC (FlexRig3)	1,500
TEXAS	478	22,000	AC (FlexRig3)	1,500
TEXAS	479	22,000	AC (FlexRig3)	1,500
TEXAS	480	22,000	AC (FlexRig3)	1,500
TEXAS	481	22,000	AC (FlexRig3)	1,500
TEXAS	482	22,000	AC (FlexRig3)	1,500
TEXAS	483	22,000	AC (FlexRig3)	1,500
TEXAS	485	22,000	AC (FlexRig3)	1,500
TEXAS	486	22,000	AC (FlexRig3)	1,500
TEXAS	487	22,000	AC (FlexRig3)	1,500
TEXAS	488	22,000	AC (FlexRig3)	1,500
TEXAS	489	22,000	AC (FlexRig3)	1,500
LOUISIANA	490	22,000	AC (FlexRig3)	1,500
TEXAS	491	22,000	AC (FlexRig3)	1,500
NORTH DAKOTA	492	22,000	AC (FlexRig3)	1,500
TEXAS	493	22,000	AC (FlexRig3)	1,500
TEXAS	494	22,000	AC (FlexRig3)	1,500
LOUISIANA	495	22,000	AC (FlexRig3)	1,500
TEXAS	496	22,000	AC (FlexRig3)	1,500
TEXAS	497	22,000	AC (FlexRig3)	1,500
TEXAS	498	22,000	AC (FlexRig3)	1,500
LOUISIANA	499	22,000	AC (FlexRig3)	1,500
PENNSYLVANIA	500	25,000+	AC (FlexRig5)	1,500
TEXAS	501	25,000+	AC (FlexRig5)	1,500
TEXAS	502	25,000+	AC (FlexRig5)	1,500
TEXAS	503	25,000+	AC (FlexRig5)	1,500
TEXAS	504	25,000+	AC (FlexRig5)	1,500
TEXAS	505	25,000+	AC (FlexRig5)	1,500
TEXAS	506	25,000+	AC (FlexRig5)	1,500
TEXAS	507	25,000+	AC (FlexRig5)	1,500
TEXAS	508	25,000+	AC (FlexRig5)	1,500
TEXAS	509	25,000+	AC (FlexRig5)	1,500
TEXAS	510	25,000+	AC (FlexRig5)	1,500
TEXAS	511	25,000+	AC (FlexRig5)	1,500
TEXAS	512	25,000+	AC (FlexRig5)	1,500
TEXAS	513	25,000+	AC (FlexRig5)	1,500
NORTH DAKOTA	515	25,000+	AC (FlexRig5)	1,500
NORTH DAKOTA	516	25,000+	AC (FlexRig5)	1,500
TEXAS	519	25,000+	AC (FlexRig5)	1,500
TEXAS	600	22,000	AC (FlexRig3)	1,500
TEXAS	601	22,000	AC (FlexRig3)	1,500
TEXAS	602	22,000	AC (FlexRig3)	1,500
TEXAS	603	22,000	AC (FlexRig3)	1,500
TEXAS	605	22,000	AC (FlexRig3)	1,500

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Location	Rig	Optimum Depth (Feet)	Rig Type	Drawworks: Horsepower
CONVENTIONAL RIGS				
OKLAHOMA	162	18,000	SCR	1,500
LOUISIANA	79	20,000	SCR	2,000
TEXAS	80	20,000	SCR	1,500
OKLAHOMA	89	20,000	SCR	1,500
OKLAHOMA	92	20,000	SCR	1,500
OKLAHOMA	94	20,000	SCR	1,500
OKLAHOMA	98	20,000	SCR	1,500
TEXAS	137	26,000	SCR	2,000
TEXAS	149	26,000	SCR	2,000
LOUISIANA	72	30,000	SCR	3,000
OKLAHOMA	73	30,000	SCR	3,000
LOUISIANA	134	30,000	SCR	3,000
TEXAS	136	30,000	SCR	3,000
TEXAS	157	30,000	SCR	3,000
LOUISIANA	161	30,000	SCR	3,000
LOUISIANA	163	30,000	SCR	3,000
OFFSHORE PLATFORM RIGS				
GULF OF MEXICO	203	20,000	Self-Erecting	2,500
GULF OF MEXICO	205	20,000	Self-Erecting	2,000
GULF OF MEXICO	206	20,000	Self-Erecting	2,000
GULF OF MEXICO	100	30,000	Conventional	3,000
GULF OF MEXICO	105	30,000	Conventional	3,000
GULF OF MEXICO	107	30,000	Conventional	3,000
GULF OF MEXICO	201	30,000	Tension-leg	3,000
GULF OF MEXICO	202	30,000	Tension-leg	3,000
GULF OF MEXICO	204	30,000	Tension-leg	3,000

The following table sets forth information with respect to the utilization of our U.S. land and offshore drilling rigs for the periods indicated:

	Years ended September 30,				
	2009	**2010**	**2011**	**2012**	**2013**
U.S. Land Rigs					
Number of rigs at end of period	201	220	248	282	302
Average rig utilization rate during period (1)	68%	73%	86%	89%	82%
U.S. Offshore Platform Rigs					
Number of rigs at end of period	9	9	9	9	9
Average rig utilization rate during period (1)	89%	80%	77%	79%	89%

(1) A rig is considered to be utilized when it is operated or being moved, assembled or dismantled under contract.

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The following table sets forth certain information concerning our international drilling rigs as of September 30, 2013:

Location	Rig	Optimum Depth (Feet)	Rig Type	Drawworks: Horsepower
UAE	476	22,000	AC (FlexRig3)	1,500
UAE	484	22,000	AC (FlexRig3)	1,500
Argentina	335	8,000	AC (FlexRig4)	1,150
Argentina	336	8,000	AC (FlexRig4)	1,150
Argentina	337	8,000	AC (FlexRig4)	1,150
Argentina	338	8,000	AC (FlexRig4)	1,150
Argentina	123	26,000	SCR	2,100
Argentina	175	30,000	SCR	3,000
Argentina	177	30,000	SCR	3,000
Argentina	151	30,000+	SCR	3,000
Argentina	230	22,000	AC (FlexRig3)	1,500
Bahrain	292	8,000	AC (FlexRig4)	1,150
Bahrain	301	8,000	AC (FlexRig4)	1,150
Bahrain	339	8,000	AC (FlexRig4)	1,150
Colombia	291	8,000	AC (FlexRig4)	1,150
Colombia	333	8,000	AC (FlexRig4)	1,150
Colombia	334	8,000	AC (FlexRig4)	1,150
Colombia	237	22,000	AC (FlexRig3)	1,500
Colombia	133	30,000	SCR	3,000
Colombia	139	30,000+	SCR	3,000
Colombia	152	30,000+	SCR	3,000
Ecuador	132	18,000	SCR	1,500
Ecuador	176	18,000	SCR	1,500
Ecuador	121	20,000	SCR	1,700
Ecuador	117	26,000	SCR	2,500
Ecuador	138	26,000	SCR	2,500
Ecuador	190	26,000	SCR	2,000
Tunisia	228	22,000	AC (FlexRig3)	1,500
Tunisia	242	22,000	AC (FlexRig3)	1,500

The following table sets forth information with respect to the utilization of our international drilling rigs for the periods indicated:

	Years ended September 30,				
	2009	2010	2011	2012	2013
Number of rigs at end of period	33	28	24	29	29
Average rig utilization rate during period (1)(2)	70%	71%	70%	77%	82%

(1) A rig is considered to be utilized when it is operated or being moved, assembled or dismantled under contract.

(2) Does not include rigs returned to the United States for major modifications and upgrades.

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STOCK PORTFOLIO

Information required by this item regarding our stock portfolio may be found on, and is incorporated by reference to, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations Stock Portfolio Held" included in this Form 10-K.

Item 3. LEGAL PROCEEDINGS

1. *Investigation by the U.S. Attorney.*

On November 8, 2013, the United States District Court for the Eastern District of Louisiana approved the previously disclosed October 30, 2013 plea agreement between our wholly owned subsidiary, Helmerich & Payne International Drilling Co., and the United States Department of Justice, United States Attorney's Office for the Eastern District of Louisiana ("DOJ"). The court's approval of the plea agreement resolved the DOJ's investigation into certain choke manifold testing irregularities that occurred in 2010 at one of Helmerich & Payne International Drilling Co.'s offshore platform rigs in the Gulf of Mexico. We are also currently engaged in discussions with the Inspector General's office of the Department of Interior regarding the same events that were the subject of the DOJ's investigation. Although we presently believe that the outcome of our discussions will not have a material adverse effect on the Company, we can provide no assurances as to the timing or eventual outcome of these discussions.

2. *Venezuela Expropriation.*

Our wholly-owned subsidiaries, Helmerich & Payne International Drilling Co. and Helmerich & Payne de Venezuela, C.A. filed a lawsuit in the United States District Court for the District of Columbia on September 23, 2011 against the Bolivarian Republic of Venezuela, Petroleos de Venezuela, S.A. ("PDVSA") and PDVSA Petroleo, S.A. ("Petroleo"). We are seeking damages for the taking of our Venezuelan drilling business in violation of international law and for breach of contract. In the third fiscal quarter of 2013 and the fourth fiscal quarter of 2012, we settled arbitration disputes with third parties not affiliated with PDVSA related to the seizure of our property in Venezuela. Proceeds of $15.0 million and $7.5 million were received and recorded as discontinued operations in 2013 and 2012, respectively.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

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OUR EXECUTIVE OFFICERS

The following table sets forth the names and ages of our executive officers, together with all positions and offices held with the Company by such executive officers. Officers are elected to serve until the meeting of the Board of Directors following the next Annual Meeting of Stockholders and until their successors have been duly elected and have qualified or until their earlier resignation or removal.

Hans Helmerich, 55	Chairman of the Board since January 2012; Chief Executive Officer since September 2012; President from 1987 and Chief Executive Officer from 1989 to September 2012; Director since 1987
John W. Lindsay, 52	President and Chief Operating Officer since September 2012; Director since September 2012; Executive Vice President and Chief Operating Officer from 2010 to September 2012; Executive Vice President, U.S. and International Operations of Helmerich & Payne International Drilling Co. from 2006 to 2012; Vice President of U.S. Land Operations of Helmerich & Payne International Drilling Co. from 1997 to 2006
Steven R. Mackey, 62	Executive Vice President, Secretary, General Counsel and Chief Administrative Officer since March 2010; Executive Vice President, Secretary and General Counsel from June 2008 to March 2010; Secretary since 1990; Vice President from 1988 to 2010; General Counsel since 1988
Juan Pablo Tardio, 48	Vice President and Chief Financial Officer since April 2010; Director of Investor Relations from January 2008 to April 2010; Manager of Investor Relations from August 2005 to January 2008

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PART II

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information

The principal market on which our common stock is traded is the New York Stock Exchange under the symbol "HP". As of November 15, 2013, there were 638 record holders of our common stock as listed by our transfer agent's records. The high and low sale prices per share for the common stock for each quarterly period during the past two fiscal years as reported in the NYSE-Composite Transaction quotations follow:

	2012		2013	
Quarter	**High**	**Low**	**High**	**Low**
First	$ 60.88	$ 35.58	$ 57.19	$ 44.95
Second	68.60	51.69	69.38	55.79
Third	55.74	38.71	66.02	55.78
Fourth	51.71	41.82	71.36	62.35

Dividends

We paid quarterly cash dividends during the past two fiscal years as shown in the table below. Payment of future dividends will depend on earnings and other factors.

	Paid per Share		Total Payment	
	Fiscal		Fiscal	
Quarter	**2012**	**2013**	**2012**	**2013**
First	$ .07	$ .07	$ 7,522,280	$ 7,430,942
Second	.07	.15	7,548,299	16,038,413
Third	.07	.15	7,549,986	16,049,768
Fourth	.07	.50	7,428,943	53,534,259

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Performance Graph

The following performance graph reflects the yearly percentage change in our cumulative total stockholder return on common stock as compared with the cumulative total return on the S&P 500 Index and the S&P 500 Oil & Gas Drilling Index. All cumulative returns assume an initial investment of $100, the reinvestment of dividends and are calculated on a fiscal year basis ending on September 30 of each year.

Comparison of Cumulative Five Year Total Return

	Base Period	**September 30,**				
Company / Index	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Helmerich & Payne, Inc.	**$ 100**	$ 92.17	$ 94.86	$ 95.61	$ 112.73	$ 165.55
S&P 500 Index	**100**	93.09	102.55	103.73	135.05	161.18
S&P 500 Oil & Gas Drilling Index	**100**	76.41	69.64	61.94	74.31	82.29

The above performance graph and related information shall not be deemed to be "soliciting material" or to be "filed" with the SEC or subject to Regulation 14A or 14C under the Securities Exchange Act of 1934 or to the liabilities of Section 18 of the Securities Exchange Act of 1934, and shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent we specifically incorporate it by reference into such a filing.

Item 6. SELECTED FINANCIAL DATA

The following table summarizes selected financial information and should be read in conjunction with Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 8 "Financial Statements and Supplementary Data" included in this Form 10-K. Amounts for fiscal year 2009 have been restated to reflect the Venezuelan operations as discontinued operations. Refer to Item 1 "Business" for additional information regarding discontinued operations.

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Five-year Summary of Selected Financial Data

	2013	2012	2011	2010	2009
	(in thousands except per share amounts)				
Operating revenues	$ 3,387,614	$ 3,151,802	$ 2,543,894	$ 1,875,162	$ 1,843,740
Income from continuing operations	721,453	573,609	434,668	286,081	380,546
Income (loss) from discontinued operations	15,186	7,436	(482)	(129,769)	(27,001)
Net Income	736,639	581,045	434,186	156,312	353,545
Basic earnings per share from continuing operations	6.75	5.35	4.06	2.70	3.61
Basic earnings (loss) per share from discontinued operations	0.14	0.07		(1.23)	(0.26)
Basic earnings per share	6.89	5.42	4.06	1.47	3.35
Diluted earnings per share from continuing operations	6.65	5.27	3.99	2.66	3.56
Diluted earnings (loss) per share from discontinued operations	0.14	0.07		(1.21)	(0.25)
Diluted earnings per share	6.79	5.34	3.99	1.45	3.31
Total assets*	6,264,827	5,721,085	5,003,891	4,265,370	4,161,024
Long-term debt	80,000	195,000	235,000	360,000	420,000
Cash dividends declared per common share	1.30	0.2800	0.2600	0.2200	0.2000

* Total assets for all years include amounts related to discontinued operations.

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

Risk Factors and Forward-Looking Statements

The following discussion should be read in conjunction with Part I of this Form 10-K as well as the Consolidated Financial Statements and related notes thereto included in Item 8 "Financial Statements and Supplementary Data" of this Form 10-K. Our future operating results may be affected by various trends and factors which are beyond our control. These include, among other factors, fluctuations in oil and natural gas prices, unexpected expiration or termination of drilling contracts, currency exchange gains and losses, expropriation of real and personal property, changes in general economic conditions, disruptions to the global credit markets, rapid or unexpected changes in technologies, risks of foreign operations, uninsured risks, changes in domestic and foreign policies, laws and regulations and uncertain business conditions that affect our businesses. Accordingly, past results and trends should not be used by investors to anticipate future results or trends.

With the exception of historical information, the matters discussed in Management's Discussion & Analysis of Financial Condition and Results of Operations include forward-looking statements. These forward-looking statements are based on various assumptions. We caution that, while we believe such assumptions to be reasonable and make them in good faith, assumed facts almost always vary from actual results. The differences between assumed facts and actual results can be material. We are including this cautionary statement to take advantage of the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by us or persons acting on our behalf. The factors identified in this cautionary statement and those factors discussed under Item 1A "Risk Factors" of this Form 10-K are important factors (but not necessarily inclusive of all important factors) that could cause actual results to differ materially from those expressed in any forward-looking statement made by us or persons acting on our behalf. Except as required by law, we

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undertake no duty to update or revise our forward-looking statements based on changes of internal estimates or expectations or otherwise.

Executive Summary

Helmerich & Payne, Inc. is primarily a contract drilling company with a total fleet of 340 drilling rigs at September 30, 2013. Our contract drilling segments consist of the U.S. Land segment with 302 rigs, the Offshore segment with nine offshore platform rigs and the International Land segment with 29 rigs at September 30, 2013. We continued to expand our rig fleet in 2013 even as pronounced volatility in oil and natural gas prices impacted drilling market conditions and prospects. Our position in the market is strengthened by our high quality fleet, our long-term contracts and our customer base. We ended our year encouraged by recent customer discussions indicating a potential increase in activity. During 2013, we placed into service 20 new FlexRigs, all with fixed-term contracts. At September 30, 2013, we had 276 active rigs, compared to 264 active rigs at the same time during the prior year.

In addition to our customers continuing efforts to further enhance drilling efficiencies, we expect them to become even more focused on technology and safety in 2014. We believe that our superior field performance and safety record will allow us to continue to gain market share over the coming years.

As further discussed in Note 2 of the Consolidated Financial Statements, our Venezuelan subsidiary was classified as discontinued operations on June 30, 2010, after the seizure of our drilling assets in that country by the Venezuelan government. Except as specifically discussed, the following results of operations pertain only to our continuing operations. Unless otherwise indicated, references to 2013, 2012 and 2011 in the following discussion are referring to our fiscal 2013, 2012 and 2011.

Results of Operations

All per share amounts included in the Results of Operations discussion are stated on a diluted basis. Our net income for 2013 was $736.6 million ($6.79 per share), compared with $581.0 million ($5.34 per share) for 2012 and $434.2 million ($3.99 per share) for 2011. Included in our net income is after-tax gains from the sale of investment securities of $97.9 million ($0.91 per share) in 2013 and $0.6 million ($0.01 per share) in 2011. Net income also includes after-tax gains from the sale of assets of $12.2 million ($0.11 per share) in 2013, $12.3 million ($0.11 per share) in 2012 and $8.8 million ($0.08 per share) in 2011.

Consolidated operating revenues were $3.4 billion in 2013, $3.2 billion in 2012 and $2.5 billion in 2011. Our total number of revenue days (drilling activity) also increased to record levels during 2013. The number of revenue days in our U.S. Land segment totaled 88,620 in 2013, compared to 86,340 in 2012 and 73,905 in 2011. Our U.S. land rig utilization was 82 percent in 2013, 89 percent in 2012 and 86 percent in 2011. The average number of U.S. land rigs available was 295 rigs in 2013, 266 rigs in 2012 and 237 rigs in 2011. Revenue in the Offshore segment increased in 2013 after declining in 2012, while rig utilization for offshore rigs was 89 percent in 2013, compared to 79 percent in 2012 and 77 percent in 2011. Revenue and rig utilization in the International Land segment increased in 2013 and 2012. Rig utilization in our International Land segment was 82 percent in 2013, 77 percent in 2012 and 70 percent in 2011.

In 2013 and 2011, we had $162.1 million and $0.9 million in gains from the sale of investment securities, respectively. We did not sell any investment securities in 2012. Interest and dividend income was $1.7 million, $1.4 million and $2.0 million in 2013, 2012 and 2011, respectively.

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Direct operating costs in 2013 were $1.9 billion or 55 percent of operating revenues, compared with $1.8 billion or 56 percent of operating revenues in 2012 and $1.4 billion or 56 percent of operating revenues in 2011.

Depreciation expense was $455.6 million in 2013, $387.5 million in 2012 and $315.5 million in 2011. Included in depreciation are abandonments of equipment of $9.1 million in 2013, $16.4 million in 2012 and $4.9 million in 2011. Depreciation expense, exclusive of the abandonments, increased over the three-year period as we placed into service 20 new rigs in 2013, 48 in 2012 and 36 in 2011. Depreciation expense in 2014 is expected to increase from 2013 from new rigs placed into service during 2013 and additional rigs placed into service during 2014. (See Liquidity and Capital Resources.)

As conditions warrant, management performs an analysis of the industry market conditions impacting its long-lived assets in each drilling segment. Based on this analysis, management determines if any impairment is required. In 2013, 2012 and 2011, no impairment was recorded.

General and administrative expenses totaled $126.3 million in 2013, $107.3 million in 2012 and $91.5 million in 2011. The $19.0 million increase in 2013 from 2012 is due to increases in salaries, bonuses, and stock-based compensation of approximately $17.3 million associated with growth in the number of employees and increases in wages in comparative periods. The remaining increase is primarily due to higher other corporate overhead associated with supporting the continued growth of our drilling business.

Interest expense was $6.1 million in 2013, $8.7 million in 2012 and $17.4 million in 2011. Interest expense is primarily attributable to the fixed-rate debt outstanding. Interest expense decreased in 2013 from 2012 primarily due to a reduction in outstanding debt balances. Capitalized interest was $8.8 million, $12.9 million and $8.2 million in 2013, 2012 and 2011, respectively. All of the capitalized interest is attributable to our rig construction program.

The provision for income taxes totaled $392.8 million in 2013, $329.0 million in 2012 and $252.4 million in 2011. The effective income tax rate was 35.3 percent in 2013 compared to 36.4 percent in 2012 and 36.7 percent in 2011. Deferred income taxes are provided for temporary differences between the financial reporting basis and the tax basis of our assets and liabilities. Recoverability of any tax assets are evaluated and necessary allowances are provided. The carrying value of the net deferred tax assets is based on management's judgments using certain estimates and assumptions that we will be able to generate sufficient future taxable income in certain tax jurisdictions to realize the benefits of such assets. If these estimates and related assumptions change in the future, additional valuation allowances may be recorded against the deferred tax assets resulting in additional income tax expense in the future. (See Note 4 of the Consolidated Financial Statements for additional income tax disclosures.)

During 2013, 2012 and 2011, we incurred $15.2 million, $16.1 million and $15.8 million, respectively, of research and development expenses primarily related to the ongoing development of the rotary steerable system tools. We anticipate research and development expenses to continue during 2014.

In 2013 and 2012, we had income from discontinued operations of $15.2 million and $7.4 million, respectively, compared to a loss from discontinued operations in 2011 of $0.5 million. In the third fiscal quarter of 2013 and the fourth fiscal quarter of 2012, we settled arbitration disputes with third parties not affiliated with the Bolivarian Republic of Venezuela, Petroleos de Venezuela, S.A. ("PDVSA") or PDVSA Petroleo, S.A. ("Petroleo") related to the seizure of our property in Venezuela. Proceeds of $15.0 million and $7.5 million were received and recorded as discontinued operations in 2013 and 2012, respectively. The loss from discontinued operations in 2011 was the result of our Venezuelan drilling business, including eleven rigs and associated real and personal property, being seized by the Venezuelan government on June 30, 2010.

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Our wholly-owned subsidiaries, Helmerich & Payne International Drilling Co. and Helmerich & Payne de Venezuela, C.A., filed a lawsuit in the United States District Court for the District of Columbia on September 23, 2011 against the Venezuelan government, PDVSA and Petroleo. Our subsidiaries seek damages for the taking of their Venezuelan drilling business in violation of international law and for breach of contract.

While there exists the possibility of realizing a recovery, we are currently unable to determine the timing or amounts we may receive, if any, or the likelihood of recovery. No gain contingencies are recognized in our Consolidated Financial Statements.

The following tables summarize operations by reportable operating segment.

Comparison of the years ended September 30, 2013 and 2012

	2013	2012	% Change
	(in thousands, except operating statistics)		
U.S. LAND OPERATIONS			
Operating revenues	$ 2,785,449	$ 2,678,475	4.0%
Direct operating expenses	1,424,716	1,407,986	1.2
General and administrative expense	37,070	30,798	20.4
Depreciation	391,072	332,723	17.5
Segment operating income	$ 932,591	$ 906,968	2.8
Operating Statistics:			
Revenue days	88,620	86,340	2.6%
Average rig revenue per day	$ 28,382	$ 27,737	2.3
Average rig expense per day	$ 13,029	$ 13,022	0.1
Average rig margin per day	$ 15,353	$ 14,715	4.3
Number of rigs at end of period	302	282	7.1
Rig utilization	82%	89%	(7.9)

Operating statistics for per day revenue, expense and margin do not include reimbursements of "out-of-pocket" expenses of $270,223 and $283,640 for 2013 and 2012, respectively. Rig utilization excludes two FlexRigs completed and ready for delivery at September 30, 2013.

Operating income in the U.S. Land segment increased to $932.6 million in 2013 from $907.0 million in 2012. Included in U.S. land revenues for 2013 is approximately $19.0 million from early termination and revenue from customers that requested delivery delays for new FlexRigs. Included in U.S. land revenues for 2012 is approximately $10.1 million from early termination revenue. Excluding early termination related revenue and customer requested delivery delay revenue for new FlexRigs, the average revenue per day for 2013 increased by $548 to $28,168 from $27,620 in 2012, primarily attributable to increases in dayrates early in 2012, which then stabilized and only slightly declined in 2013.

Direct operating expenses as a percentage of revenue were 51 percent in 2013 and 53 percent in 2012.

Rig utilization decreased to 82 percent in 2013 from 89 percent in 2012. The total number of rigs at September 30, 2013 was 302 compared to 282 rigs at September 30, 2012. The net increase is due to 20 new FlexRigs completed and placed into service, two new FlexRigs completed and ready for delivery and two older conventional rigs removed from service.

Subsequent to September 30, 2013, we announced we had entered into agreements with five customers to build and operate 13 new FlexRigs. As of November 14, 2013, nine announced FlexRigs

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remained to be delivered. We expect to complete and deliver approximately two rigs per month through September 2014.

Depreciation includes charges for abandoned equipment of $8.2 million and $15.9 million in 2013 and 2012, respectively. Included in abandonments is the removal of two conventional rigs in 2013 and seven mechanical highly mobile rigs in 2012. Excluding the abandonment amounts, depreciation in 2013 increased 21 percent from 2012 due to the increase in available rigs. As a result of the new FlexRigs added in fiscal 2013 and additional rigs scheduled for completion in fiscal 2014, we anticipate depreciation expense to continue to increase in fiscal 2014.

At September 30, 2013, 248 out of 302 existing rigs in the U.S. Land segment were generating revenue. Of the 248 rigs generating revenue, 158 were under fixed-term contracts, and 90 were working in the spot market. At November 14, 2013, the number of existing rigs under fixed-term contracts in the segment was 156 and the number of rigs working in the spot market increased to 99.

Comparison of the years ended September 30, 2013 and 2012

	2013	2012	% Change
	(in thousands, except operating statistics)		
OFFSHORE OPERATIONS			
Operating revenues	$ 221,863	$ 189,086	17.3%
Direct operating expenses	146,184	126,470	15.6
General and administrative expense	8,849	7,386	19.8
Depreciation	13,766	13,455	2.3
Segment operating income	$ 53,064	$ 41,775	27.0
Operating Statistics:			
Revenue days	2,920	2,625	11.2%
Average rig revenue per day	$ 61,069	$ 53,927	13.2
Average rig expense per day	$ 37,654	$ 33,051	13.9
Average rig margin per day	$ 23,415	$ 20,876	12.2
Number of rigs at end of period	9	9	
Rig utilization	89%	79%	12.7

Operating statistics for per day revenue, expense and margin do not include reimbursements of "out-of-pocket" expenses of $19,701 and $18,346 for 2013 and 2012, respectively. Also excluded are the effects of offshore platform management contracts and currency revaluation expense.

Segment operating income in our Offshore segment increased by 27.0 percent in 2013 from 2012 primarily due to an increase in revenue days and an increase in dayrates reduced by a one-time charge of $6.4 million more fully discussed in Note 13 to the Consolidated Financial Statements. The increase in revenue days is primarily due to two rigs working all of 2013 compared to working only a portion of 2012, offset partially by a third rig completing its contract in 2012 and being idle during 2013. At September 30, 2013 and 2012, eight of our nine rigs were working.

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Comparison of the years ended September 30, 2013 and 2012

	2013	2012	% Change
	(in thousands, except operating statistics)		
INTERNATIONAL LAND OPERATIONS			
Operating revenues	$ 366,841	$ 270,027	35.9%
Direct operating expenses	282,335	215,642	30.9
General and administrative expense	3,911	3,318	17.9
Depreciation	36,000	30,701	17.3
Segment operating income	$ 44,595	$ 20,366	119.0
Operating Statistics:			
Revenue days	8,707	7,343	18.6%
Average rig revenue per day	$ 37,246	$ 32,998	12.9
Average rig expense per day	$ 27,589	$ 25,524	8.1
Average rig margin per day	$ 9,657	$ 7,474	29.2
Number of rigs at end of period	29	29	
Rig utilization	82%	77%	6.5

Operating statistics for per day revenue, expense and margin do not include reimbursements of "out-of-pocket" expenses of $42,542 and $27,720 for 2013 and 2012, respectively. Also excluded are the effects of currency revaluation expense.

The International Land segment had operating income of $44.6 million for 2013 compared to $20.4 million for 2012. Included in International land revenues in 2013 is approximately $5.3 million related to early termination fees.

Revenues in 2013 increased by $96.8 million from 2012 in our international land operations with rig utilization increasing to 82 percent in 2013 from 77 percent in 2012. The total number of rigs remained constant at 29. The average revenue per day for 2013 compared to 2012 increased $4,248 of which $609 is attributable to the early termination related revenue. The remaining increase is primarily due to higher dayrates.

In April 2013, we announced we had entered into an agreement to build a new 3,000 horsepower AC drive rig which is scheduled to begin operations in the International Land segment in the spring of 2014.

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Comparison of the years ended September 30, 2012 and 2011

	2012	2011	% Change
	(in thousands, except operating statistics)		
U.S. LAND OPERATIONS			
Operating revenues	$ 2,678,475	$ 2,100,508	27.5%
Direct operating expenses	1,407,986	1,119,700	25.7
General and administrative expense	30,798	25,066	22.9
Depreciation	332,723	264,127	26.0
Segment operating income	$ 906,968	$ 691,615	31.1
Operating Statistics:			
Revenue days	86,340	73,905	16.8%
Average rig revenue per day	$ 27,737	$ 25,809	7.5
Average rig expense per day	$ 13,022	$ 12,538	3.9
Average rig margin per day	$ 14,715	$ 13,271	10.9
Number of rigs at end of period	282	248	13.7
Rig utilization	89%	86%	3.5

Operating statistics for per day revenue, expense and margin do not include reimbursements of "out-of-pocket" expenses of $283,640 and $193,093 for 2012 and 2011, respectively.

Operating income in the U.S. Land segment increased to $907.0 million in 2012 from $691.6 million in 2011. Included in U.S. land revenues for 2012 and 2011 was approximately $10.1 million and $5.4 million, respectively, from early termination revenue. Excluding early termination related revenue, the average revenue per day for 2012 increased by $1,885 to $27,620 from $25,735 in 2011, primarily attributable to increases in dayrates in 2012 compared to 2011.

Direct operating expenses increased 25.7 percent in 2012 from 2011; however, the expense as a percentage of revenue was 53 percent in 2012 and 2011.

Rig utilization increased to 89 percent in 2012 from 86 percent in 2011. The total number of rigs at September 30, 2012 was 282 compared to 248 rigs at September 30, 2011. The net increase is due to 46 new FlexRigs having been completed and placed into service, three FlexRigs transferred to the International Land segment, three idle conventional rigs sold, and four older mechanical highly mobile rigs and two older conventional rigs removed from service.

Depreciation includes charges for abandoned equipment of $15.9 million and $3.8 million in 2012 and 2011, respectively. Excluding the abandonment amounts, depreciation in 2012 increased 22 percent from 2011 due to the increase in available rigs.

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Comparison of the years ended September 30, 2012 and 2011

	2012	2011	% Change
	(in thousands, except operating statistics)		
OFFSHORE OPERATIONS			
Operating revenues	$ 189,086	$ 201,417	(6.1)%
Direct operating expenses	126,470	135,368	(6.6)
General and administrative expense	7,386	6,074	21.6
Depreciation	13,455	14,684	(8.4)
Segment operating income	$ 41,775	$ 45,291	(7.8)
Operating Statistics:			
Revenue days	2,625	2,544	3.2%
Average rig revenue per day	$ 53,927	$ 51,794	4.1
Average rig expense per day	$ 33,051	$ 29,379	12.5
Average rig margin per day	$ 20,876	$ 22,415	(6.9)
Number of rigs at end of period	9	9	
Rig utilization	79%	77%	2.6

Operating statistics for per day revenue, expense and margin do not include reimbursements of "out-of-pocket" expenses of $18,346 and $33,718 for 2012 and 2011, respectively. Also excluded are the effects of offshore platform management contracts and currency revaluation expense.

Segment operating income and average rig margin per day in our Offshore segment declined in 2012 from 2011 partly because our rig previously working offshore Trinidad completed its contract in the first quarter of fiscal 2012, returned to the U.S. during the second quarter of fiscal 2012 and was idle the remainder of the fiscal year. Additionally, a second rig was on standby for five months during 2012 compared to working all of 2011.

Comparison of the years ended September 30, 2012 and 2011

	2012	2011	% Change
	(in thousands, except operating statistics)		
INTERNATIONAL LAND OPERATIONS			
Operating revenues	$ 270,027	$ 226,849	19.0%
Direct operating expenses	215,642	175,728	22.7
General and administrative expense	3,318	3,392	(2.2)
Depreciation	30,701	28,018	9.6
Segment operating income	$ 20,366	$ 19,711	3.3
Operating Statistics:			
Revenue days	7,343	6,406	14.6%
Average rig revenue per day	$ 32,998	$ 31,633	4.3
Average rig expense per day	$ 25,524	$ 23,416	9.0
Average rig margin per day	$ 7,474	$ 8,217	(9.0)
Number of rigs at end of period	29	24	20.8
Rig utilization	77%	70%	10.0

Operating statistics for per day revenue, expense and margin do not include reimbursements of "out-of-pocket" expenses of $27,720 and $24,207 for 2012 and 2011, respectively. Also excluded are the effects of currency revaluation expense.

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The International Land segment had operating income of $20.4 million for 2012 compared to $19.7 million for 2011.

Revenues in 2012 increased by $43.2 million from 2011 in our international land operations with rig utilization increasing to 77 percent in 2012 from 70 percent in 2011. The total number of rigs at September 30, 2012 was 29 compared to 24 rigs at September 30, 2011. The increase was due to two new FlexRigs having been completed and placed into service and three FlexRigs transferred from the U.S. Land segment.

Segment operating income and average margin per day decreased in 2012 compared to 2011 primarily due to early termination revenue earned in 2011 and higher operating expenses in 2012.

LIQUIDITY AND CAPITAL RESOURCES

Our capital spending was $809.1 million in 2013, $1.1 billion in 2012 and $694.3 million in 2011. Net cash provided from operating activities was $997.2 million in 2013, $1.0 billion in 2012 and $977.6 million in 2011. Our 2014 capital spending is currently estimated at $850 million. In addition to capital maintenance requirements, tubulars and other special projects, this annual estimate assumes a continued new build cadence of two rigs per month through September 2014.

Historically, we have financed operations primarily through internally generated cash flows. In periods when internally generated cash flows are not sufficient to meet liquidity needs, we will either borrow from available credit sources or we may sell portfolio securities. Likewise, if we are generating excess cash flows, we may invest in short-term money market securities.

We manage a portfolio of marketable securities that, at the close of fiscal 2013, had a fair value of $305.6 million consisting of Atwood Oceanics, Inc. and Schlumberger, Ltd. The value of the portfolio is subject to fluctuation in the market and may vary considerably over time. The portfolio is recorded at fair value on our balance sheet.

During 2013, we had cash proceeds from the sale of investment securities of $232.2 million including $214.1 from the sale of marketable equity available-for-sale securities and $18.1 million from the sale of three limited partnerships. We generated cash proceeds from the sale of an investment in a limited partnership of $3.9 million in 2011. We did not sell any portfolio securities in 2012.

Our proceeds from asset sales totaled $28.0 million in 2013, $39.9 million in 2012 and $26.8 million in 2011. Income from asset sales in 2013 totaled $18.9 million. In each year we had sales of old or damaged rig equipment and drill pipe used in the ordinary course of business.

The Company has authorization from the Board of Directors for the repurchase of up to four million common shares in any calendar year. The repurchases may be made using our cash and cash equivalents or other available sources. During fiscal 2012, we purchased 1,747,819 common shares at an aggregate cost of $77.6 million, which are held as treasury shares. We had no purchases of common shares in fiscal 2013.

During 2013, we increased our dividend in both the first fiscal quarter and the third fiscal quarter, representing the 41st consecutive year of dividend increases. We paid dividends of $0.87 per share, or a total of $93.1 million during 2013.

We have $75 million of intermediate-term unsecured debt obligations that mature in August 2014. The interest rate through maturity will be 6.56 percent. The terms of the debt obligations require that we maintain a ratio of debt to total capitalization of less than 55 percent.

We have $120 million senior unsecured fixed-rate notes outstanding at September 30, 2013 that mature over a period from July 2014 to July 2016. Interest on the notes is paid semi-annually based on an annual rate of 6.10 percent. Annual principal repayments of $40 million are due July 2014 through

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July 2016. We have complied with our financial covenants which require us to maintain a funded leverage ratio of less than 55 percent and an interest coverage ratio (as defined) of not less than 2.50 to 1.00.

We have a $300 million unsecured revolving credit facility that will mature May 25, 2017. The credit facility has $100 million available to use for letters of credit. We anticipate that the majority of any borrowings under the facility will accrue interest at a spread over the London Interbank Offered Rate (LIBOR). We will also pay a commitment fee based on the unused balance of the facility. Borrowing spreads as well as commitment fees are determined according to a scale based on a ratio of our total debt to total capitalization. The spread over LIBOR ranges from 1.125 percent to 1.75 percent per annum and commitment fees range from .15 percent to .35 percent per annum. Based on our debt to total capitalization on September 30, 2013, the spread over LIBOR and commitment fees would be 1.125 percent and .15 percent, respectively. Financial covenants in the facility require us to maintain a funded leverage ratio (as defined) of less than 50 percent and an interest coverage ratio (as defined) of not less than 3.00 to 1.00. The credit facility contains additional terms, conditions, restrictions, and covenants that we believe are usual and customary in unsecured debt arrangements for companies of similar size and credit quality. As of September 30, 2013, there were no borrowings, but there were two letters of credit outstanding in the amount of $27.2 million. The two outstanding letters of credit replaced two collateral trusts that were terminated during the first quarter of fiscal 2013. Upon termination, an amount totaling $26.1 million was returned to us. At September 30, 2013, we had $272.8 million available to borrow under our $300 million unsecured credit facility. Subsequent to September 30, 2013, we issued a third letter of credit against the credit facility in the amount of $3.5 million, which reduced the amount available to borrow to $269.3 million.

At September 30, 2013, we had two letters of credit outstanding, totaling $12 million that were issued to support international operations. These letters of credit were issued separately from the $300 million credit facility so they do not reduce the available borrowing capacity discussed in the previous paragraph.

The applicable agreements for all of the unsecured debt described above contain additional terms, conditions and restrictions that we believe are usual and customary in unsecured debt arrangements for companies that are similar in size and credit quality. At September 30, 2013, we were in compliance with all debt covenants.

At September 30, 2013, we had 176 existing rigs with contracts under fixed terms with original term durations ranging from six months to seven years, with some expiring in fiscal 2014. The contracts provide for termination at the election of the customer, with an early termination payment to be paid if a contract is terminated prior to the expiration of the fixed term. While most of our customers are primarily major oil companies and large independent oil companies, a risk exists that a customer, especially a smaller independent oil company, may become unable to meet its obligations and may exercise its early termination election in the future and not be able to pay the early termination fee. Although not expected at this time, our future revenue and operating results could be negatively impacted if this were to happen.

Our operating cash requirements, scheduled debt repayments, any stock repurchases and estimated capital expenditures, including our rig construction program, for fiscal 2014 are expected to be funded through current cash, cash provided from operating activities and, possibly, from funds available under our credit facility and from sales of available-for-sale securities.

The current ratio was 2.8 at September 30, 2013 and 2.4 at September 30, 2012. The long-term debt to total capitalization ratio, including the current portion of long-term debt, was four percent at September 30, 2013 compared to six percent at September 30, 2012.

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STOCK PORTFOLIO HELD

September 30, 2013	Number of Shares	Cost Basis	Market Value
	(in thousands, except share amounts)		
Atwood Oceanics, Inc.	4,000,000	$ 60,749	$ 220,160
Schlumberger, Ltd.	967,500	7,685	85,488
Total		$ 68,434	$ 305,648

Material Commitments

We have no off balance sheet arrangements other than operating leases discussed below. Our contractual obligations as of September 30, 2013, are summarized in the table below in thousands:

	Payments due by year						
Contractual Obligations	Total	2014	2015	2016	2017	2018	After 2018
Long-term debt and estimated interest (a)	$ 212,934	$ 126,564	$ 44,405	$ 41,965	$	$	$
Operating leases (b)	32,688	5,443	3,536	2,807	2,720	2,726	15,456
Purchase obligations (b)	79,615	79,615					
Total contractual obligations	$ 325,237	$ 211,622	$ 47,941	$ 44,772	$ 2,720	$ 2,726	$ 15,456

(a) *Interest on fixed-rate debt was estimated based on principal maturities. See Note 3 "Debt" to our Consolidated Financial Statements.*

(b) *See Note 13 "Commitments and Contingencies" to our Consolidated Financial Statements.*

The above table does not include obligations for our pension plan or amounts recorded for uncertain tax positions.

In 2013, we contributed $2.1 million to the pension plan. Based on current information available from plan actuaries, we estimate contributing at least $0.1 million in 2014 to meet the minimum contribution required by law. Additional contributions may be made in 2014 to fund unexpected distributions in lieu of liquidating pension assets. Future contributions beyond 2014 are difficult to estimate due to multiple variables involved.

At September 30, 2013, we had $13.3 million recorded for uncertain tax positions and related interest and penalties. However, the timing of such payments to the respective taxing authorities cannot be estimated at this time. Income taxes are more fully described in Note 4 to the Consolidated Financial Statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Consolidated Financial Statements are impacted by the accounting policies used and by the estimates and assumptions made by management during their preparation. These estimates and assumptions are evaluated on an on-going basis. Estimates are based on historical experience and on various other assumptions that we believe to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates under different assumptions or conditions. The following is a discussion of the critical accounting policies and estimates used in our financial statements. Other significant accounting policies are summarized in Note 1 to the Consolidated Financial Statements.

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Property, Plant and Equipment Property, plant and equipment, including renewals and betterments, are stated at cost, while maintenance and repairs are expensed as incurred. Interest costs applicable to the construction of qualifying assets is capitalized as a component of the cost of such assets. We account for the depreciation of property, plant and equipment using the straight-line method over the estimated useful lives of the assets considering the estimated salvage value of the property, plant and equipment. Both the estimated useful lives and salvage values require the use of management estimates. Certain events, such as unforeseen changes in operations, technology or market conditions, could materially affect our estimates and assumptions related to depreciation. Management believes that these estimates have been materially accurate in the past. For the years presented in this report, no significant changes were made to the determinations of useful lives or salvage values. Upon retirement or other disposal of fixed assets, the cost and related accumulated depreciation are removed from the respective accounts and any gains or losses are recorded in the results of operations.

Impairment of Long-lived Assets Management assesses the potential impairment of our long-lived assets whenever events or changes in conditions indicate that the carrying value of an asset may not be recoverable. Changes that could prompt such an assessment may include equipment obsolescence, changes in the market demand for a specific asset, periods of relatively low rig utilization, declining revenue per day, declining cash margin per day, completion of specific contracts and/or overall changes in general market conditions. If a review of the long-lived assets indicates that the carrying value of certain of these assets is more than the estimated undiscounted future cash flows, an impairment charge is made to adjust the carrying value to the estimated fair market value of the asset. The fair value of drilling rigs is determined based upon estimated discounted future cash flows or estimated fair market value, if available. Cash flows are estimated by management considering factors such as prospective market demand, recent changes in rig technology and its effect on each rig's marketability, any cash investment required to make a rig marketable, suitability of rig size and makeup to existing platforms, and competitive dynamics including utilization. Fair value is estimated, if applicable, considering factors such as recent market sales of rigs of other companies and our own sales of rigs, appraisals and other factors. Use of different assumptions could result in an impairment charge different from that reported.

Fair Value of Financial Instruments Fair value is defined as an exit price, which is the price that would be received upon sale of an asset or paid upon transfer of a liability in an orderly transaction between market participants at the measurement date. The degree of judgment utilized in measuring the fair value of assets and liabilities generally correlates to the level of pricing observability. Financial assets and liabilities with readily available, actively quoted prices or for which fair value can be measured from actively quoted prices in active markets generally have more pricing observability and require less judgment in measuring fair value. Conversely, financial assets and liabilities that are rarely traded or not quoted have less price observability and are generally measured at fair value using valuation models that require more judgment. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the price transparency of the asset, liability or market and the nature of the asset or liability. The carrying amounts reported in the statement of financial position for current assets and current liabilities qualifying as financial instruments approximate fair value because of the short-term nature of the instruments. Marketable securities are carried at fair value which is generally determined by quoted market prices. We have categorized financial assets and liabilities measured at fair value into a three-level hierarchy in accordance with Accounting Standards Codification ("ASC") 820. (See Note 8 of the Consolidated Financial Statements for fair value disclosures.)

Self-Insurance Accruals We self-insure a significant portion of expected losses relating to worker's compensation, general liability, employer's liability and automobile liability. Generally, deductibles range from $1 million to $3 million per occurrence depending on the coverage and whether a claim occurs outside or inside of the United States. Insurance is purchased over deductibles to reduce our

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exposure to catastrophic events. Estimates are recorded for incurred outstanding liabilities for worker's compensation, general liability claims and for claims that are incurred but not reported. Estimates are based on adjusters' estimates, historic experience and statistical methods that we believe are reliable. Nonetheless, insurance estimates include certain assumptions and management judgments regarding the frequency and severity of claims, claim development and settlement practices. Unanticipated changes in these factors may produce materially different amounts of expense that would be reported under these programs.

Our wholly-owned captive insurance company finances a significant portion of the physical damage risk on company-owned drilling rigs as well as international casualty deductibles. With the exception of "named wind storm" risk in the Gulf of Mexico, we insure rig and related equipment at values that approximate the current replacement cost on the inception date of the policy. We self-insure a $5 million per occurrence deductible, as well as 20 percent of the estimated replacement cost of offshore rigs and 30 percent of the estimated replacement cost for land rigs and equipment. We have two insurance policies covering eight offshore platform rigs for "named windstorm" risk in the Gulf of Mexico. The first policy covers four rigs and has a $75 million aggregate insurance limit over a $3 million deductible. The second policy covers four rigs and has a $40 million aggregate limit and a $3.5 million deductible. We maintain certain other insurance coverage with deductibles as high as $2.5 million. Excess insurance is purchased over these coverage amounts to limit our exposure to catastrophic claims, but there can be no assurance that such coverage will respond or be adequate in all circumstances. Retained losses are estimated and accrued based upon our estimates of the aggregate liability for claims incurred and, using adjuster's estimates, our historical loss experience or estimation methods that are believed to be reliable. Nonetheless, insurance estimates include certain assumptions and management judgments regarding the frequency and severity of claims, claim development and settlement practices. Unanticipated changes in these factors may produce materially different amounts of expense and related liabilities. We self-insure a number of other risks including loss of earnings and business interruption.

Pension Costs and Obligations Our pension benefit costs and obligations are dependent on various actuarial assumptions. We make assumptions relating to discount rates and expected return on plan assets. Our discount rate is determined by matching projected cash distributions with the appropriate corporate bond yields in a yield curve analysis. The discount rate was raised to 4.80 percent from 4.06 percent as of September 30, 2013 to reflect changes in the market conditions for high-quality fixed-income investments. The expected return on plan assets is determined based on historical portfolio results and future expectations of rates of return. Actual results that differ from estimated assumptions are accumulated and amortized over the estimated future working life of the plan participants and could therefore affect the expense recognized and obligations in future periods. As of September 30, 2006, the Pension Plan was frozen and benefit accruals were discontinued. As a result, the rate of compensation increase assumption has been eliminated from future periods. We anticipate pension expense to decrease approximately $1.6 million in 2014 from 2013.

Stock-Based Compensation Historically, we have granted stock-based awards to key employees and non-employee directors as part of their compensation. We estimate the fair value of all stock option awards as of the date of grant by applying the Black-Scholes option-pricing model. The application of this valuation model involves assumptions, some of which are judgmental and highly sensitive. These assumptions include, among others, the expected stock price volatility, the expected life of the stock options and the risk-free interest rate. Expected volatilities were estimated using the historical volatility of our stock based upon the expected term of the option. We consider information in determining the grant date fair value that would have indicated that future volatility would be expected to be significantly different from historical volatility. The expected term of the option was derived from historical data and represents the period of time that options are estimated to be outstanding. The risk-free interest rate for periods within the estimated life of the option was based on the U.S. Treasury

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Strip rate in effect at the time of the grant. The fair value of each award is amortized on a straight-line basis over the vesting period for awards granted to employees. Stock-based awards granted to non-employee directors are expensed immediately upon grant.

The fair value of restricted stock awards is determined based on the closing price of our common stock on the date of grant. We amortize the fair value of restricted stock awards to compensation expense on a straight-line basis over the vesting period. At September 30, 2013, unrecognized compensation cost related to unvested restricted stock was $17.5 million. The cost is expected to be recognized over a weighted-average period of 2.7 years.

Revenue Recognition Contract drilling revenues are comprised of daywork drilling contracts for which the related revenues and expenses are recognized as services are performed and collection is reasonably assured. For certain contracts, we receive payments contractually designated for the mobilization of rigs and other drilling equipment. Mobilization payments received, and direct costs incurred for the mobilization, are deferred and recognized over the term of the related drilling contract. Costs incurred to relocate rigs and other drilling equipment to areas in which a contract has not been secured are expensed as incurred. Reimbursements received for out-of-pocket expenses are recorded as both revenues and direct costs. For contracts that are terminated prior to the specified term, early termination payments received by us are recognized as revenues when all contractual requirements are met.

NEW ACCOUNTING STANDARDS

On October 1, 2012, we adopted Accounting Standards Update ("ASU") No. 2011-04, *Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs.* ASU No. 2011-04 is intended to create consistency between U.S. GAAP and International Financial Reporting Standards ("IFRS") on the definition of fair value and on the guidance on how to measure fair value and on what to disclose about fair value measurements. The adoption of these provisions had no material impact on the Consolidated Financial Statements.

On October 1, 2012, we adopted ASU No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income.* ASU No. 2011-05 was issued to increase the prominence of other comprehensive income ("OCI") in financial statements. Our presentation of OCI is shown in a separate statement and was applied retrospectively. The adoption had no impact on the amount of OCI reported in the Consolidated Financial Statements.

In February 2013, the Financial Accounting Standards Board ("FASB") issued ASU 2013-2, *Other Comprehensive Income*. This ASU amends ASC 220, *Comprehensive Income*, and supersedes and replaces ASU 2011-05 *Presentation of Comprehensive Income* and ASU 2011-12 *Comprehensive Income*, to require reclassification adjustments from other comprehensive income to be presented either in the financial statements or in the notes to the financial statements. The standard does not change the current requirements for reporting net income or other comprehensive income in financial statements. However, the guidance does require an entity to provide enhanced disclosures to present separately by component reclassifications out of accumulated other comprehensive income. The amendments in this ASU are effective prospectively for reporting periods beginning after December 15, 2012. We do not believe adoption of this guidance will have a material impact on our Consolidated Financial Statements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Foreign Currency Exchange Rate Risk We have operations in several South American countries, Africa and the Middle East. Our exposure to currency valuation losses is usually immaterial due to the fact that virtually all invoice billings and receipts in other countries are in U.S. dollars.

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We are not operating in any country that is currently considered highly inflationary, which is defined as cumulative inflation rates exceeding 100 percent in the most recent three-year period. All of our foreign operations use the U.S. dollar as the functional currency and local currency monetary assets and liabilities are remeasured into U.S. dollars with gains and losses resulting from foreign currency transactions included in current results of operations. As such, if a foreign economy is considered highly inflationary, there would be no impact on the Consolidated Financial Statements.

Commodity Price Risk The demand for contract drilling services is a result of exploration and production companies spending money to explore and develop drilling prospects in search of crude oil and natural gas. Their spending is driven by their cash flow and financial strength, which is affected by trends in crude oil and natural gas commodity prices. Crude oil prices are determined by a number of factors including supply and demand, worldwide economic conditions and geopolitical factors. Crude oil and natural gas prices have historically been volatile and very difficult to predict. While current energy prices are important contributors to positive cash flow for customers, expectations about future prices and price volatility are generally more important for determining future spending levels. This volatility can lead many exploration and production companies to base their capital spending on much more conservative estimates of commodity prices. As a result, demand for contract drilling services is not always purely a function of the movement of commodity prices.

Credit and Capital Market Risk In addition, customers may finance their exploration activities through cash flow from operations, the incurrence of debt or the issuance of equity. Any deterioration in the credit and capital markets, as experienced in 2008 and 2009, can make it difficult for customers to obtain funding for their capital needs. A reduction of cash flow resulting from declines in commodity prices or a reduction of available financing may result in a reduction in customer spending and the demand for drilling services. This reduction in spending could have a material adverse effect on our business, financial condition and results of operations.

We attempt to secure favorable prices through advanced ordering and purchasing for drilling rig components. While these materials have generally been available at acceptable prices, there is no assurance the prices will not vary significantly in the future. Any fluctuations in market conditions causing increased prices in materials and supplies could have a material adverse effect on future operating costs.

Interest Rate Risk Our interest rate risk exposure results primarily from short-term rates, mainly LIBOR-based, on borrowings from our commercial banks. Because all of our debt at September 30, 2013 has fixed-rate interest obligations, there is no current risk due to interest rate fluctuation.

The following tables provide information as of September 30, 2013 and 2012 about our interest rate risk sensitive instruments:

INTEREST RATE RISK AS OF SEPTEMBER 30, 2013 (dollars in thousands)

	2014	2015	2016	2017	2018	After 2018	Total	Fair Value 9/30/13
Fixed-Rate Debt	$ 115,000	$ 40,000	$ 40,000	$	$	$	$ 195,000	$ 205,386
Average Interest Rate	6.5%	6.1%	6.1%	%	%	%	6.3%	
Variable Rate Debt	$	$	$	$	$	$	$	$
Average Interest Rate								

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INTEREST RATE RISK AS OF SEPTEMBER 30, 2012 (dollars in thousands)

	2013	2014	2015	2016	2017	After 2017	Total	Fair Value 9/30/12
Fixed-Rate Debt	$ 40,000	$ 115,000	$ 40,000	$ 40,000	$	$	$ 235,000	$ 252,705
Average Interest Rate	6.1%	6.5%	6.1%	6.1%	%	%	6.3%	
Variable Rate Debt	$	$	$	$	$	$	$	$
Average Interest Rate								

Equity Price Risk On September 30, 2013, we had a portfolio of securities with a total fair value of $305.6 million. The total fair value of the portfolio of securities was $451.6 million at September 30, 2012. We make no specific plans to sell securities, but rather sell securities based on market conditions and other circumstances. These securities are subject to a wide variety and number of market-related risks that could substantially reduce or increase the fair value of our holdings. The portfolio is recorded at fair value on the balance sheet with changes in unrealized after-tax value reflected in the equity section of the balance sheet. At November 14, 2013, the total fair value of the remaining securities had increased to approximately $322.4 million with an estimated after-tax value of $198.2 million. Currently, the fair value exceeds the cost of the investments. We continually monitor the fair value of the investments but are unable to predict future market volatility and any potential impact to the Consolidated Financial Statements.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Information required by this item may be found in Item 1A "Risk Factors" and in Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures About Market Risk" included in this Form 10-K.

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Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Consolidated Financial Statements

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Report of Independent Registered Public Accounting Firm
HELMERICH & PAYNE, INC.

The Board of Directors and Shareholders of
Helmerich & Payne, Inc.

We have audited the accompanying consolidated balance sheets of Helmerich & Payne, Inc. as of September 30, 2013 and 2012, and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2013. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Helmerich & Payne, Inc. at September 30, 2013 and 2012, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2013, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Helmerich & Payne, Inc.'s internal control over financial reporting as of September 30, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated November 27, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
November 27, 2013

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Consolidated Statements of Income

HELMERICH & PAYNE, INC.

	Years Ended September 30,		
	2013	**2012**	**2011**
	(in thousands, except per share amounts)		
Operating revenues			
Drilling U.S. Land	$ 2,785,449	$ 2,678,475	$ 2,100,508
Drilling Offshore	221,863	189,086	201,417
Drilling International Land	366,841	270,027	226,849
Other	13,461	14,214	15,120
	3,387,614	3,151,802	2,543,894
Operating costs and expenses			
Operating costs, excluding depreciation	1,852,768	1,750,510	1,432,602
Depreciation	455,623	387,549	315,468
Research and development	15,235	16,060	15,764
General and administrative	126,250	107,307	91,452
Income from asset sales	(18,923)	(19,223)	(13,903)
	2,430,953	2,242,203	1,841,383
Operating income from continuing operations	**956,661**	**909,599**	**702,511**
Other income (expense)			
Interest and dividend income	1,653	1,380	1,951
Interest expense	(6,129)	(8,653)	(17,355)
Gain on sale of investment securities	162,121		913
Other	(9)	254	(953)
	157,636	(7,019)	(15,444)
Income from continuing operations before income taxes	1,114,297	902,580	687,067
Income tax provision	392,844	328,971	252,399
Income from continuing operations	721,453	573,609	434,668
Income (loss) from discontinued operations before income taxes	14,701	7,355	(487)
Income tax provision (benefit)	(485)	(81)	(5)
Income (loss) from discontinued operations	15,186	7,436	(482)
NET INCOME	**$ 736,639**	**$ 581,045**	**$ 434,186**
Basic earnings per common share:			
Income from continuing operations	$ 6.75	$ 5.35	$ 4.06
Income from discontinued operations	$ 0.14	$ 0.07	$
Net income	$ 6.89	$ 5.42	$ 4.06
Diluted earnings per common share:			
Income from continuing operations	$ 6.65	$ 5.27	$ 3.99
Income from discontinued operations	$ 0.14	$ 0.07	$

Net income	$	6.79	$	5.34	$	3.99
Weighted average shares outstanding (in thousands):						
Basic		106,286		106,819		106,643
Diluted		107,879		108,377		108,632

The accompanying notes are an integral part of these statements.

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Consolidated Statements of Comprehensive Income

HELMERICH & PAYNE, INC.

	Years Ended September 30,		
	2013	2012	2011
		(in thousands)	
Net income	$ 736,639	$ 581,045	$ 434,186
Other comprehensive income, net of income taxes:			
Unrealized appreciation on securities, net of income taxes of $34.2 million at September 30, 2013, $37.2 million at September 30, 2012 and $11.0 million at September 30, 2011	46,853	63,725	18,414
Reclassification of realized gains in net income, net of income taxes of ($60.8) million at September 30, 2013	(92,543)		
Minimum pension liability adjustments, net of income taxes of $6.6 million at September 30, 2013, $2.4 million at September 30, 2012 and ($2.2) million at September 30, 2011	11,413	4,174	(3,613)
Other comprehensive income (loss)	(34,277)	67,899	14,801
Comprehensive income	$ 702,362	$ 648,944	$ 448,987

The accompanying notes are an integral part of these statements.

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Consolidated Balance Sheets

HELMERICH & PAYNE, INC.

	September 30, 2013	September 30, 2012
	(in thousands)	
Assets		
CURRENT ASSETS:		
Cash and cash equivalents	$ 447,868	$ 96,095
Accounts receivable, less reserve of $4,795 in 2013 and $942 in 2012	621,420	620,489
Inventories	88,866	78,777
Deferred income taxes	16,414	17,555
Prepaid expenses and other	79,938	74,693
Current assets of discontinued operations	3,705	7,619
Total current assets	1,258,211	895,228
INVESTMENTS	316,154	451,144
PROPERTY, PLANT AND EQUIPMENT, at cost:		
Contract drilling equipment	6,493,606	5,743,354
Construction in progress	153,252	215,754
Real estate properties	63,542	62,177
Other	310,515	284,813
	7,020,915	6,306,098
Less-Accumulated depreciation	2,344,812	1,954,527
Net property, plant and equipment	4,676,103	4,351,571
NONCURRENT ASSETS:		
Other assets	14,359	23,142
TOTAL ASSETS	$ 6,264,827	$ 5,721,085

The accompanying notes are an integral part of these statements.

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Consolidated Balance Sheets (Continued)

HELMERICH & PAYNE, INC.

	September 30, 2013	September 30, 2012
	(in thousands, except share data and per share amounts)	
Liabilities and Shareholders' Equity		
CURRENT LIABILITIES:		
Accounts payable	$ 144,379	$ 159,420
Accrued liabilities	189,684	176,615
Long-term debt due within one year	115,000	40,000
Current liabilities of discontinued operations	3,210	5,129
Total current liabilities	452,273	381,164
NONCURRENT LIABILITIES:		
Long-term debt	80,000	195,000
Deferred income taxes	1,222,981	1,209,040
Other	65,351	98,393
Noncurrent liabilities of discontinued operations	495	2,490
Total noncurrent liabilities	1,368,827	1,504,923
SHAREHOLDERS' EQUITY:		
Common stock, $.10 par value, 160,000,000 shares authorized, 108,738,577 and 107,598,889 shares issued as of September 30, 2013 and 2012, respectively, and 106,716,970 and 105,697,693 shares outstanding as of September 30, 2013 and 2012, respectively	10,874	10,760
Preferred stock, no par value, 1,000,000 shares authorized, no shares issued		
Additional paid-in capital	288,758	236,240
Retained earnings	4,102,663	3,505,295
Accumulated other comprehensive income	132,530	166,807
	4,534,825	3,919,102
Less treasury stock, 2,021,607 shares in 2013 and 1,901,196 shares in 2012, at cost	91,098	84,104
Total shareholders' equity	4,443,727	3,834,998
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 6,264,827	$ 5,721,085

The accompanying notes are an integral part of these statements.

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Consolidated Statements of Shareholders' Equity

HELMERICH & PAYNE, INC.

	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock		Total
	Shares	Amount				Shares	Amount	
	(in thousands, except per share amounts)							
Balance, September 30, 2010	107,058	$ 10,706	$ 191,900	$ 2,547,917	$ 84,107	1,239	$ (27,165)	$ 2,807,465
Comprehensive Income:								
Net income				434,186				434,186
Other comprehensive income (loss):								
Change in value on available-for-sale securities, net of income taxes					18,414			18,414
Amortization of net periodic benefit costs net of actuarial loss					(3,613)			(3,613)
Total other comprehensive income								14,801
Total comprehensive income								448,987
Dividends declared ($.26 per share)				(27,893)				(27,893)
Exercise of stock options	185	18	(3,942)			(948)	19,365	15,441
Tax benefit of stock-based awards, including excess tax benefits of $13.4 million			13,946					13,946
Stock issued for vested restricted stock			(3,096)			(134)	3,096	
Stock-based compensation			12,101					12,101
Balance, September 30, 2011	107,243	10,724	210,909	2,954,210	98,908	157	(4,704)	3,270,047
Comprehensive Income:								
Net income				581,045				581,045
Other comprehensive income								
Change in value on available-for-sale securities, net of income taxes					63,725			63,725
Amortization of net periodic benefit costs net of actuarial gain					4,174			4,174
Total other comprehensive income								67,899
Total comprehensive income								648,944
Dividends declared ($.28 per share)				(29,960)				(29,960)
Exercise of stock options	315	32	5,398			47	(2,757)	2,673
Tax benefit of stock-based awards, including excess tax benefits of $3.6 million			4,340					4,340
Stock issued for vested restricted stock, net of shares withheld for employee taxes	41	4	(2,485)			(51)	967	(1,514)
Repurchase of common stock						1,748	(77,610)	(77,610)
Stock-based compensation			18,078					18,078
Balance, September 30, 2012	107,599	10,760	236,240	3,505,295	166,807	1,901	(84,104)	3,834,998
Comprehensive Income:								
Net income				736,639				736,639
Other comprehensive income (loss)								
Change in value on available-for-sale securities, net of income taxes					(45,690)			(45,690)
Amortization of net periodic benefit costs net of actuarial gain					11,413			11,413

Total other comprehensive loss								(34,277)
Total comprehensive income								702,362
Dividends declared ($1.30 per share)				(139,271)				(139,271)
Exercise of stock options	1,057	106	21,746			162	(8,535)	13,317
Tax benefit of stock-based awards, including excess tax benefits of $10.7 million			10,727					10,727
Stock issued for vested restricted stock, net of shares withheld for employee taxes	83	8	(3,226)			(41)	1,541	(1,677)
Stock-based compensation			23,271					23,271
Balance, September 30, 2013	108,739	$ 10,874	$ 288,758	$ 4,102,663	$ 132,530	2,022	$ (91,098)	$ 4,443,727

The accompanying notes are an integral part of these statements.

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Consolidated Statements of Cash Flows

HELMERICH & PAYNE, INC.

	Years Ended September 30,		
	2013	**2012**	**2011**
		(in thousands)	
OPERATING ACTIVITIES:			
Net income	$ 736,639	$ 581,045	$ 434,186
Adjustment for (income) loss from discontinued operations	(15,186)	(7,436)	482
Income from continuing operations	721,453	573,609	434,668
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	455,623	387,549	315,468
Provision for bad debt	3,875	205	106
Stock-based compensation	23,271	18,078	12,101
Gain on sale of investment securities	(162,121)		(913)
Income from asset sales	(18,923)	(19,223)	(13,903)
Deferred income tax expense	29,557	196,931	187,651
Other	2,490		
Change in assets and liabilities:			
Accounts receivable	(4,806)	(160,154)	(2,987)
Inventories	(12,289)	(22,170)	(11,005)
Prepaid expenses and other	5,730	(27,758)	12,623
Accounts payable	(52,076)	54,906	17,362
Accrued liabilities	24,259	195	20,483
Deferred income taxes	(1,673)	(180)	251
Other noncurrent liabilities	(17,371)	(1,592)	6,129
Net cash provided by operating activities from continuing operations	996,999	1,000,396	978,034
Net cash provided by (used in) operating activities from discontinued operations	186	(64)	(482)
Net cash provided by operating activities	997,185	1,000,332	977,552
INVESTING ACTIVITIES:			
Capital expenditures	(809,066)	(1,097,680)	(694,264)
Acquisition of TerraVici Drilling Solutions			(4,000)
Proceeds from asset sales	28,026	39,894	26,795
Proceeds from sale of investments	232,221		3,932
Net cash used in investing activities from continuing operations	(548,819)	(1,057,786)	(667,537)
Net cash provided by investing activities from discontinued operations	15,000	7,500	
Net cash used in investing activities	(533,819)	(1,050,286)	(667,537)
FINANCING ACTIVITIES:			
Payments on long-term debt	(40,000)	(115,000)	
Proceeds from line of credit		20,000	10,000
Payments on line of credit		(20,000)	(20,000)
Repurchase of common stock		(77,610)	
Dividends paid	(93,053)	(30,049)	(26,741)
Exercise of stock options	13,317	2,673	15,441
Tax withholdings related to net share settlements of restricted stock operations	(1,677)	(1,514)	
Excess tax benefit from stock-based compensation	9,820	3,303	12,511
Net cash used in financing activities	(111,593)	(218,197)	(8,789)
Net increase (decrease) in cash and cash equivalents	351,773	(268,151)	301,226
Cash and cash equivalents, beginning of period	96,095	364,246	63,020

Cash and cash equivalents, end of period	$ 447,868	$ 96,095	$ 364,246

The accompanying notes are an integral part of these statements.

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Notes to Consolidated Financial Statements

HELMERICH & PAYNE, INC.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of Helmerich & Payne, Inc. and its wholly-owned subsidiaries. Fiscal years of our foreign operations end on August 31 to facilitate reporting of consolidated results. There were no significant intervening events that materially affected the financial statements.

BASIS OF PRESENTATION

We classified our former Venezuelan operation, an operating segment within the International Land segment, as a discontinued operation in the third quarter of fiscal 2010, as more fully described in Note 2. Unless indicated otherwise, the information in the Notes to Consolidated Financial Statements relates only to our continuing operations.

FOREIGN CURRENCIES

The functional currency for all our foreign operations is the U.S. dollar. Nonmonetary assets and liabilities are translated at historical rates and monetary assets and liabilities are translated at exchange rates in effect at the end of the period. Income statement accounts are translated at average rates for the year. Gains and losses from remeasurement of foreign currency financial statements and foreign currency translations into U.S. dollars are included in direct operating costs. Included in direct operating costs are aggregate foreign currency remeasurement and transaction gains of $0.7 million and $0.3 million in fiscal 2013 and 2012, respectively, and losses totalling $1.2 million in fiscal 2011.

USE OF ESTIMATES

The preparation of our financial statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect 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 those estimates.

RECENTLY ADOPTED ACCOUNTING STANDARDS

On October 1, 2012, we adopted Accounting Standards Update ("ASU") No. 2011-04, *Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs.* ASU No. 2011-04 is intended to create consistency between U.S. GAAP and International Financial Reporting Standards ("IFRS") on the definition of fair value and on the guidance on how to measure fair value and on what to disclose about fair value measurements. The adoption of these provisions had no material impact on the Consolidated Financial Statements.

On October 1, 2012, we adopted ASU No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income.* ASU No. 2011-05 was issued to increase the prominence of other comprehensive income ("OCI") in financial statements. Our presentation of OCI is shown in a separate statement and was applied retrospectively. The adoption had no impact on the amount of OCI reported in the Consolidated Financial Statements.

Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

CASH AND CASH EQUIVALENTS

Cash equivalents consist of investments in short-term, highly liquid securities having original maturities of three months or less. The carrying values of these assets approximate their fair values. We primarily utilize a cash management system with a series of separate accounts consisting of lockbox accounts for receiving cash, concentration accounts, and several "zero-balance" disbursement accounts for funding payroll and accounts payable. As a result of our cash management system, checks issued, but not presented to the banks for payment, may create negative book cash balances.

RESTRICTED CASH AND CASH EQUIVALENTS

We had restricted cash and cash equivalents of $25.7 million and $31.0 million at September 30, 2013 and 2012, respectively. The cash is restricted for the purpose of potential insurance claims in our wholly-owned captive insurance company. Of the total at September 30, 2013, $2.0 million is from the initial capitalization of the captive company and management has elected to restrict an additional $23.7 million. The restricted amounts are primarily invested in short-term money market securities.

The restricted cash and cash equivalents are reflected in the balance sheet as follows:

	September 30,	
	2013	2012
	(in thousands)	
Prepaid expenses and other	$ 23,691	$ 28,989
Other assets	$ 2,000	$ 2,000

INVENTORIES AND SUPPLIES

Inventories and supplies are primarily replacement parts and supplies held for use in our drilling operations. Inventories and supplies are valued at the lower of cost (moving average or actual) or market value.

INVESTMENTS

We maintain investments in equity securities of certain publicly traded companies. The cost of securities used in determining realized gains and losses is based on the average cost basis of the security sold.

We regularly review investment securities for impairment based on criteria that include the extent to which the investment's carrying value exceeds its related fair value, the duration of the market decline and the financial strength and specific prospects of the issuer of the security. Unrealized losses that are other than temporary are recognized in earnings.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are stated at cost less accumulated depreciation. Substantially all property, plant and equipment are depreciated using the straight-line method based on the estimated useful lives of the assets (contract drilling equipment, 4-15 years; real estate buildings and equipment, 10-45 years; and other, 2-23 years). Depreciation in the Consolidated Statements of Income includes abandonments of $9.1 million, $16.4 million and $4.9 million for fiscal 2013, 2012 and 2011,

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

respectively. The cost of maintenance and repairs is charged to direct operating cost, while betterments and refurbishments are capitalized.

We lease office space and equipment for use in operations. Leases are evaluated at inception or at any subsequent material modification and, depending on the lease terms, are classified as either capital leases or operating leases as appropriate under Accounting Standards Codification ("ASC") 840, *Leases*. We do not have significant capital leases.

CAPITALIZATION OF INTEREST

We capitalize interest on major projects during construction. Interest is capitalized based on the average interest rate on related debt. Capitalized interest for fiscal 2013, 2012 and 2011 was $8.8 million, $12.9 million and $8.2 million, respectively.

VALUATION OF LONG-LIVED ASSETS

We review long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Changes that could prompt such an assessment include a significant decline in revenue or cash margin per day, extended periods of low rig utilization, changes in market demand for a specific asset, obsolescence, completion of specific contracts and/or overall general market conditions. If a review of the long-lived assets indicates that the carrying value of certain of these assets is more than the estimated undiscounted future cash flows, an impairment charge is made to adjust the carrying value down to the estimated fair value of the asset. The fair value of drilling rigs is determined based upon estimated discounted future cash flows or estimated fair market value, if available. Cash flows are estimated by management considering factors such as prospective market demand, recent changes in rig technology and its effect on each rig's marketability, any cash investment required to make a rig marketable, suitability of rig size and make up to existing platforms, and competitive dynamics including industry utilization. Fair value is estimated, if applicable, considering factors such as recent market sales of rigs of other companies and our own sales of rigs, appraisals and other factors.

SELF-INSURANCE ACCRUALS

We have accrued a liability for estimated worker's compensation and other casualty claims incurred. The liability for other benefits to former or inactive employees after employment but before retirement is not material.

DRILLING REVENUES

Contract drilling revenues are comprised of daywork drilling contracts for which the related revenues and expenses are recognized as services are performed and collection is reasonably assured. For certain contracts, we receive payments contractually designated for the mobilization of rigs and other drilling equipment. Mobilization payments received, and direct costs incurred for the mobilization, are deferred and recognized on a straight-line basis over the term of the related drilling contract. Costs incurred to relocate rigs and other drilling equipment to areas in which a contract has not been secured are expensed as incurred. Reimbursements received for out-of-pocket expenses are recorded as both revenues and direct costs. Reimbursements for fiscal 2013, 2012 and 2011 were $332.5 million, $329.7 million and $251.0 million, respectively. For contracts that are terminated prior

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

to the specified term, early termination payments received by us are recognized as revenues when all contractual requirements are met.

RENT REVENUES

We enter into leases with tenants in our rental properties consisting primarily of retail and multi-tenant warehouse space. The lease terms of tenants occupying space in the retail centers and warehouse buildings generally range from three to ten years. Minimum rents are recognized on a straight-line basis over the term of the related leases. Overage and percentage rents are based on tenants' sales volume. Recoveries from tenants for property taxes and operating expenses are recognized in other operating revenues in the Consolidated Statements of Income. Our rent revenues are as follows:

	Years Ended September 30,		
	2013	2012	2011
	(in thousands)		
Minimum rents	$ 9,009	$ 8,757	$ 8,941
Overage and percentage rents	$ 1,384	$ 1,485	$ 1,135

At September 30, 2013, minimum future rental income to be received on noncancelable operating leases was as follows:

Fiscal Year	Amount (in thousands)
2014	$ 7,837
2015	6,479
2016	4,892
2017	3,999
2018	2,650
Thereafter	5,790
Total	$ 31,647

Leasehold improvement allowances are capitalized and amortized over the lease term.

At September 30, 2013 and 2012, the cost and accumulated depreciation for real estate properties were as follows:

	September 30,	
	2013	2012
	(in thousands)	
Real estate properties	$ 63,542	$ 62,177
Accumulated depreciation	(41,847)	(40,882)
	$ 21,695	$ 21,295

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

INCOME TAXES

Current income tax expense is the amount of income taxes expected to be payable for the current year. Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial basis and the tax basis of our assets and liabilities.

We provide for uncertain tax positions when such tax positions do not meet the recognition thresholds or measurement standards prescribed in ASC 740, *Income Taxes*, which is more fully discussed in Note 4. Amounts for uncertain tax positions are adjusted in periods when new information becomes available or when positions are effectively settled. We recognize accrued interest related to unrecognized tax benefits in interest expense and penalties in other expense in the Consolidated Statements of Income.

EARNINGS PER SHARE

Basic earnings per share is computed utilizing the two-class method and is calculated based on the weighted-average number of common shares outstanding during the periods presented. Diluted earnings per share is computed using the weighted-average number of common and common equivalent shares outstanding during the periods utilizing the two-class method for stock options and nonvested restricted stock.

STOCK-BASED COMPENSATION

We record compensation expense associated with stock options in accordance with ASC 718, *Compensation Stock Compensation*. Compensation expense is determined using a fair-value-based measurement method for all awards granted. In computing the impact, the fair value of each option is estimated on the date of grant based on the Black-Scholes options-pricing model utilizing certain assumptions for a risk free interest rate, volatility, dividend yield and expected remaining term of the awards. The assumptions used in calculating the fair value of share-based payment awards represent management's best estimates, but these estimates involve inherent uncertainties and the application of management judgment. Stock-based compensation is recognized on a straight-line basis over the requisite service periods of the stock awards, which is generally the vesting period. Compensation expense related to stock options is recorded as a component of general and administrative expenses in the Consolidated Statements of Income.

TREASURY STOCK

Treasury stock purchases are accounted for under the cost method whereby the cost of the acquired stock is recorded as treasury stock. Gains and losses on the subsequent reissuance of shares are credited or charged to additional paid-in capital using the average-cost method.

NEW ACCOUNTING STANDARDS

In February 2013, the Financial Accounting Standards Board ("FASB") issued ASU 2013-2, *Other Comprehensive Income*. This ASU amends ASC 220, *Comprehensive Income*, and supersedes and replaces ASU 2011-05, *Presentation of Comprehensive Income*, and ASU 2011-12, *Comprehensive Income*, to require reclassification adjustments from other comprehensive income to be presented either in the financial statements or in the notes to the financial statements. The standard does not change

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

the current requirements for reporting net income or other comprehensive income in financial statements. However, the guidance does require an entity to provide enhanced disclosures to present separately by component reclassifications out of accumulated other comprehensive income. The amendments in this ASU are effective prospectively for reporting periods beginning after December 15, 2012. We do not believe adoption of this guidance will have a material impact on our Consolidated Financial Statements.

NOTE 2 DISCONTINUED OPERATIONS

On June 30, 2010, the Official Gazette of Venezuela published the Decree of Venezuelan President Hugo Chavez, which authorized the "forceful acquisition" of eleven rigs owned by our Venezuelan subsidiary. The Decree also authorized the seizure of "all the personal and real property and other improvements" used by our Venezuelan subsidiary in its drilling operations. The seizing of our assets became effective June 30, 2010, and met the criteria established for recognition as discontinued operations under accounting standards for presentation of financial statements. Therefore, operations from the Venezuelan subsidiary, an operating segment previously within the International Land segment, have been classified as discontinued operations in our Consolidated Financial Statements.

Summarized operating results from discontinued operations are as follows:

	Years Ended September 30,		
	2013	2012	2011
	(in thousands)		
Revenue	$	$	$
Income (loss) before income taxes	14,701	7,355	(487)
Income tax benefit	(485)	(81)	(5)
Income (loss) from discontinued operations	$ 15,186	$ 7,436	$ (482)

Income from discontinued operations in fiscal 2013 and 2012 is attributable to proceeds from arbitration, as more fully described in Note 13, net of expenses incurred for in-country obligations.

Significant categories of assets and liabilities from discontinued operations are as follows:

	September 30,	
	2013	2012
	(in thousands)	
Other current assets	$ 3,705	$ 7,619
Total assets	$ 3,705	$ 7,619
Total current liabilities	$ 3,210	$ 5,129
Total noncurrent liabilities	495	2,490
Total liabilities	$ 3,705	$ 7,619

Other current assets consist of restricted cash to meet remaining in-country current obligations. Liabilities consist of municipal and income taxes payable and social obligations due within the country of Venezuela.

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 3 DEBT

At September 30, 2013 and 2012, we had $80 million and $195 million, respectively, in unsecured long-term debt outstanding at rates and maturities shown in the following table:

	September 30, 2013	September 30, 2012
	(in thousands)	
Unsecured intermediate debt issued August 15, 2002:		
Series D, due August 15, 2014, 6.56%	$ 75,000	$ 75,000
Unsecured senior notes issued July 21, 2009:		
Due July 21, 2013, 6.10%		40,000
Due July 21, 2014, 6.10%	40,000	40,000
Due July 21, 2015, 6.10%	40,000	40,000
Due July 21, 2016, 6.10%	40,000	40,000
	$ 195,000	$ 235,000
Less long-term debt due within one year	115,000	40,000
Long-term debt	$ 80,000	$ 195,000

The intermediate unsecured debt outstanding at September 30, 2013 matures August 15, 2014 and carries an interest rate of 6.56 percent, which is paid semi-annually. The terms require that we maintain a ratio of debt to total capitalization of less than 55 percent. The debt is held by various entities.

We have $120 million senior unsecured fixed-rate notes outstanding at September 30, 2013 that mature over a period from July 2014 to July 2016. Interest on the notes is paid semi-annually based on an annual rate of 6.10 percent. Annual principal repayments of $40 million are due July 2014 through July 2016. We have complied with our financial covenants which require us to maintain a funded leverage ratio of less than 55 percent and an interest coverage ratio (as defined) of not less than 2.50 to 1.00.

We have a $300 million unsecured revolving credit facility that will mature May 25, 2017. The credit facility has $100 million available to use for letters of credit. We anticipate that the majority of any borrowings under the facility will accrue interest at a spread over the London Interbank Offered Rate (LIBOR). We will also pay a commitment fee based on the unused balance of the facility. Borrowing spreads as well as commitment fees are determined according to a scale based on a ratio of our total debt to total capitalization. The spread over LIBOR ranges from 1.125 percent to 1.75 percent per annum and commitment fees range from .15 percent to .35 percent per annum. Based on our debt to total capitalization on September 30, 2013, the spread over LIBOR and commitment fees would be 1.125 percent and .15 percent, respectively. Financial covenants in the facility require us to maintain a funded leverage ratio (as defined) of less than 50 percent and an interest coverage ratio (as defined) of not less than 3.00 to 1.00. The credit facility contains additional terms, conditions, restrictions, and covenants that we believe are usual and customary in unsecured debt arrangements for companies of similar size and credit quality. As of September 30, 2013, there were no borrowings, but there were two letters of credit outstanding in the amount of $27.2 million. The two outstanding letters of credit replaced two collateral trusts that were terminated during the first quarter of fiscal 2013. Upon termination, an amount totaling $26.1 million was returned to us. At September 30, 2013, we had $272.8 million available to borrow under our $300 million unsecured credit facility. Subsequent to

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 3 DEBT (Continued)

September 30, 2013, we issued a third letter of credit against the credit facility in the amount of $3.5 million, which reduced the amount available to borrow to $269.3 million.

At September 30, 2013, we had two letters of credit outstanding, totaling $12 million that were issued to support international operations. These letters of credit were issued separately from the $300 million credit facility so they do not reduce the available borrowing capacity discussed in the previous paragraph.

The applicable agreements for all unsecured debt described in this Note 3 contain additional terms, conditions and restrictions that we believe are usual and customary in unsecured debt arrangements for companies that are similar in size and credit quality. At September 30, 2013, we were in compliance with all debt covenants.

At September 30, 2013, aggregate maturities of long-term debt are as follows (in thousands):

Years ending September 30,	
2014	$ 115,000
2015	40,000
2016	40,000
	$ 195,000

NOTE 4 INCOME TAXES

The components of the provision for income taxes are as follows:

	Years Ended September 30,		
	2013	**2012**	**2011**
		(in thousands)	
Current:			
Federal	$ 315,820	$ 108,297	$ 42,377
Foreign	14,551	13,201	14,259
State	32,916	10,542	8,112
	363,287	132,040	64,748
Deferred:			
Federal	35,530	196,373	185,076
Foreign	(1,409)	(6,484)	(4,117)
State	(4,564)	7,042	6,692
	29,557	196,931	187,651
Total provision	$ 392,844	$ 328,971	$ 252,399

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 4 INCOME TAXES (Continued)

The amounts of domestic and foreign income before income taxes are as follows:

	Years Ended September 30,		
	2013	2012	2011
	(in thousands)		
Domestic	$ 1,071,435	$ 886,484	$ 666,073
Foreign	42,862	16,096	20,994
	$ 1,114,297	$ 902,580	$ 687,067

Deferred income taxes are provided for the temporary differences between the financial reporting basis and the tax basis of our assets and liabilities. Recoverability of any tax assets are evaluated and necessary allowances are provided. The carrying value of the net deferred tax assets is based on management's judgments using certain estimates and assumptions that we will be able to generate sufficient future taxable income in certain tax jurisdictions to realize the benefits of such assets. If these estimates and related assumptions change in the future, additional valuation allowances may be recorded against the deferred tax assets resulting in additional income tax expense in the future.

The components of our net deferred tax liabilities are as follows:

	September 30,	
	2013	2012
	(in thousands)	
Deferred tax liabilities:		
Property, plant and equipment	$ 1,161,134	$ 1,103,769
Available-for-sale securities	117,567	154,463
Other	55	4
Total deferred tax liabilities	1,278,756	1,258,236
Deferred tax assets:		
Pension reserves	2,146	9,482
Self-insurance reserves	8,357	7,737
Net operating loss and foreign tax credit carryforwards	54,867	59,730
Financial accruals	48,963	39,833
Other	7,487	6,533
Total deferred tax assets	121,820	123,315
Valuation allowance	49,631	56,564
Net deferred tax assets	72,189	66,751
Net deferred tax liabilities	$ 1,206,567	$ 1,191,485

The change in our net deferred tax assets and liabilities is impacted by foreign currency remeasurement.

As of September 30, 2013, we had state and foreign net operating loss carryforwards for income tax purposes of $15.6 million and $35.5 million, respectively, and foreign tax credit carryforwards of approximately $45.2 million (of which $41.4 million is reflected as a deferred tax asset in our Consolidated Financial Statements prior to consideration of our valuation allowance) which will expire

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 4 INCOME TAXES (Continued)

in fiscal 2014 through 2023. The valuation allowance is primarily attributable to state and foreign net operating loss carryforwards of $1.2 million and $11.0 million, respectively, and foreign tax credit carryforwards of $37.4 million which more likely than not will not be utilized.

Effective income tax rates as compared to the U.S. Federal income tax rate are as follows:

	Years Ended September 30,		
	2013	**2012**	**2011**
U.S. Federal income tax rate	35.0%	35.0%	35.0%
Effect of foreign taxes	1.1	0.7	0.6
State income taxes, net of federal tax benefit	1.5	1.4	1.8
U.S. domestic production activities	(2.1)	(1.1)	(0.5)
Other	(0.2)	0.4	(0.2)
Effective income tax rate	35.3%	36.4%	36.7%

We recognize accrued interest related to unrecognized tax benefits in interest expense, and penalties in other expense in the Consolidated Statements of Income. As of September 30, 2013 and 2012, we had accrued interest and penalties of $5.2 million and $6.1 million, respectively.

A reconciliation of the change in our gross unrecognized tax benefits for the fiscal year ended September 30, 2013 and 2012 is as follows:

	September 30,	
	2013	**2012**
	(in thousands)	
Unrecognized tax benefits at October 1,	$ 8,438	$ 6,878
Gross decreases tax positions in prior periods	(914)	(4)
Gross increases tax positions in prior periods	1,896	2,632
Gross decreases current period effect of tax positions	(437)	(384)
Gross increases current period effect of tax positions	147	142
Expiration of statute of limitations for assessments	(1,001)	(826)
Unrecognized tax benefits at September 30,	$ 8,129	$ 8,438

As of September 30, 2013 and September 30, 2012, our liability for unrecognized tax benefits would affect the effective tax rate if recognized. The liabilities for unrecognized tax benefits and related interest and penalties are included in other noncurrent liabilities in our Consolidated Balance Sheets.

For the next 12 months, we cannot predict with certainty whether we will achieve ultimate resolution of any uncertain tax position associated with our international operations that could result in increases or decreases of our unrecognized tax benefits. However, we believe it is reasonably possible that the reserve for uncertain tax positions may increase by approximately $7.6 million to $10.2 million during the next 12 months due to an international matter.

We file a consolidated U.S. federal income tax return, as well as income tax returns in various states and foreign jurisdictions. The tax years that remain open to examination by U.S. federal and state jurisdictions include fiscal 2009 through 2012. Audits in foreign jurisdictions are generally complete through fiscal 2001.

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 5 SHAREHOLDERS' EQUITY

On September 30, 2013, we had 106,716,970 outstanding preferred stock purchase rights ("Rights") pursuant to the terms of the Rights Agreement dated January 8, 1996, as amended by Amendment No. 1 dated December 8, 2005. As adjusted for the two-for-one stock splits in fiscal 1998 and fiscal 2006, and as long as the Rights are not separately transferable, one-half Right attaches to each share of our common stock. Under the terms of the Rights Agreement each Right entitles the holder thereof to purchase one full unit consisting of one one-thousandth of a share of Series A Junior Participating Preferred Stock ("Preferred Stock"), without par value, at a price of $250 per unit. The exercise price and the number of units of Preferred Stock issuable on exercise of the Rights are subject to adjustment in certain cases to prevent dilution. The Rights will be attached to the common stock certificates and are not exercisable or transferable apart from the common stock, until ten business days after a person acquires 15 percent or more of the outstanding common stock or ten business days following the commencement of a tender offer or exchange offer that would result in a person owning 15 percent or more of the outstanding common stock. In that event, each holder of a Right (other than the acquiring person) shall have the right to receive, upon exercise of the Right, common stock of the Company having a value equal to two times the exercise price of the Right. In the event we are acquired in a merger or certain other business combination transactions (including one in which we are the surviving corporation), or more than 50 percent of our assets or earning power is sold or transferred, each holder of a Right shall have the right to receive, upon exercise of the Right, common stock of the acquiring company having a value equal to two times the exercise price of the Right. The Rights are redeemable under certain circumstances at $0.01 per Right and will expire, unless earlier redeemed, on January 31, 2016.

The Company has authorization from the Board of Directors for the repurchase of up to four million common shares in any calendar year. The repurchases may be made using our cash and cash equivalents or other available sources. During fiscal 2012, we purchased 1,747,819 common shares at an aggregate cost of $77.6 million, which are held as treasury shares. We had no purchases of common shares in fiscal 2013.

NOTE 6 STOCK-BASED COMPENSATION

On March 2, 2011, the 2010 Long-Term Incentive Plan (the "2010 Plan") was approved by our stockholders. The 2010 Plan, among other things, authorizes the Board of Directors to grant nonqualified stock options, restricted stock awards and stock appreciation rights to selected employees and to non-employee Directors. Restricted stock may be granted for no consideration other than prior and future services. The purchase price per share for stock options may not be less than market price of the underlying stock on the date of grant. Stock options expire 10 years after the grant date. We have the right to satisfy option exercises from treasury shares and from authorized but unissued shares. There were 364,624 nonqualified stock options and 307,100 shares of restricted stock awards granted under the 2010 Plan during fiscal 2013. Awards outstanding in the 2005 Long-Term Incentive Plan (the "2005 Plan") and one prior equity plan remain subject to the terms and conditions of those plans.

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 6 STOCK-BASED COMPENSATION (Continued)

A summary of compensation cost for stock-based payment arrangements recognized in general and administrative expense in fiscal 2013, 2012 and 2011 is as follows:

	September 30,		
	2013	2012	2011
	(in thousands)		
Compensation expense			
Stock options	$ 11,512	$ 9,791	$ 7,224
Restricted stock	11,759	8,287	4,877
	$ 23,271	$ 18,078	$ 12,101

Benefits of tax deductions in excess of recognized compensation cost of $9.8 million, $3.3 million and $12.5 million are reported as a financing cash flow in the Consolidated Statements of Cash Flows for fiscal 2013, 2012 and 2011, respectively.

STOCK OPTIONS

Vesting requirements for stock options are determined by the Human Resources Committee of our Board of Directors. Options currently outstanding began vesting one year after the grant date with 25 percent of the options vesting for four consecutive years.

We use the Black-Scholes formula to estimate the fair value of stock options granted to employees. The fair value of the options is amortized to compensation expense on a straight-line basis over the requisite service periods of the stock awards, which are generally the vesting periods. The weighted-average fair value calculations for options granted within the fiscal period are based on the following weighted-average assumptions set forth in the table below. Options that were granted in prior periods are based on assumptions prevailing at the date of grant.

	2013	2012	2011
Risk-free interest rate	0.7%	1.0%	1.9%
Expected stock volatility	53.9%	53.3%	51.6%
Dividend yield	1.1%	0.4%	0.5%
Expected term (in years)	5.5	5.5	5.5

Risk-Free Interest Rate. The risk-free interest rate is based on U.S. Treasury securities for the expected term of the option.

Expected Volatility Rate. Expected volatilities are based on the daily closing price of our stock based upon historical experience over a period which approximates the expected term of the option.

Expected Dividend Yield. The dividend yield is based on our current dividend yield.

Expected Term. The expected term of the options granted represents the period of time that they are expected to be outstanding. We estimate the expected term of options granted based on historical experience with grants and exercises.

Based on these calculations, the weighted-average fair value per option granted to acquire a share of common stock was $23.80, $27.70 and $22.20 per share for fiscal 2013, 2012 and 2011, respectively.

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Notes to Consolidated Financial Statements (Continued)

HELMERICH & PAYNE, INC.

NOTE 6 STOCK-BASED COMPENSATION (Continued)

The following summary reflects the stock option activity for our common stock and related information for fiscal 2013, 2012 and 2011 (shares in thousands):

	2013		2012		2011	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at October 1,	4,690	$ 29.56	4,589	$ 25.84	5,572	$ 22.82
Granted	365	54.18	456	59.68	324	47.94
Exercised	(1,057)	20.68	(314)	17.24	(1,289)	18.24
Forfeited/Expired	(7)	52.32	(41)	42.21	(18)	34.06
Outstanding on September 30,	3,991	$ 34.12	4,690	$ 29.56	4,589	$ 25.84
Exercisable on September 30,	3,063	$ 28.48	3,575	$ 24.66	3,287	$ 22.35
Shares available to grant	4,116		5,082		6,000	

The following table summarizes information about stock options at September 30, 2013 (shares in thousands):