ATWOOD OCEANICS INC
Form 10-K
November 19, 2012

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, 2012

or

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

COMMISSION FILE NUMBER 1-13167

ATWOOD OCEANICS, INC.
(Exact name of registrant as specified in its charter)

TEXAS	74-1611874
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
15835 Park Ten Place Drive Houston, Texas	77084
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code:
281-749-7800

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

Title of each class	Name of each exchange on which registered
Common Stock $1.00 par value	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 ý No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ 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 filings requirements for the past 90 days. Yes ý No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K ¨.

Indicate by check mark whether the registrant is a large accelerated filer, accelerated filer, a non-accelerated filer, or a smaller reporting company. See 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	¨
Non-accelerated filer	¨ (Do not check if a Smaller Reporting Company)	Smaller Reporting Company	¨

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which our Common Stock, $1.00 par value, was last sold, or the average bid and asked price of such Common Stock, as of March 31, 2012 was $2.9 billion.

The number of shares outstanding of our Common Stock, $1.00 par value, as of November 1, 2012: 65,464,000.

DOCUMENTS INCORPORATED BY REFERENCE

(1) Proxy Statement for 2013 Annual Meeting of Shareholders - Referenced in Part III of this report.

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FORWARD-LOOKING STATEMENTS

Statements included in this Form 10-K regarding future financial performance, capital sources and results of operations and other statements, other than statements of historical fact, that address activities, events or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Such statements are those concerning strategic plans, expectations and objectives for future operations and performance. When used in this report, the words “believes,” “expects,” “anticipates,” “plans,” “intends,” “estimates,” “projects,” “could,” “s “may,” or similar expressions are intended to be among the statements that identify forward-looking statements. Such statements are subject to numerous risks, uncertainties and assumptions that are beyond our ability to control, including, but not limited to:

- prices of oil and natural gas and industry expectations about future prices;
- market conditions, expansion and other development trends in the drilling industry and the global economy in general;
- the operational risks involved in drilling for oil and gas;
- the highly competitive and volatile nature of our business;
- the impact of governmental or industry regulation, both in the United States and internationally;
- the risks of and disruptions to international operations, including political instability and the impact of terrorist acts, acts of piracy, embargoes, war or other military operations;
- our ability to enter into, and the terms of, future drilling contracts, including contracts for our newbuild units and for rigs whose contracts are expiring;
- our ability to obtain and retain qualified personnel to operate our vessels;
- timely access to spare parts, equipment and personnel to maintain and service our fleet;
- the termination or renegotiation of contracts by customers or payment or other delays by our customers;
- customer requirements for drilling capacity and customer drilling plans;
- the adequacy of sources of liquidity for us and for our customers;
- changes in tax laws, treaties and regulations;
- the risks involved in the construction, upgrade, and repair of our drilling units;
- unplanned downtime and repairs on our rigs; and
- such other risks discussed in Item 1A. “Risk Factors” of this Form 10-K and in our other reports filed with the Securities and Exchange Commission, or SEC.

Forward-looking statements are made based upon management’s current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements. Undue reliance should not be placed on these forward-looking statements, which are applicable only on the date hereof. We undertake no obligation to revise or update these forward-looking statements to reflect events or circumstances that arise after the date hereof or to reflect the occurrence of unanticipated events.

PART I

ITEM 1. BUSINESS

Atwood Oceanics, Inc. (which together with its subsidiaries is identified as the "Company," "we," "us" or "our," except where stated or the context requires otherwise) is a global offshore drilling contractor engaged in the drilling and completion of exploratory and developmental oil and gas wells. We currently own a diversified fleet of 11 mobile offshore drilling units located in the U.S. Gulf of Mexico, the Mediterranean Sea, offshore West Africa, offshore Southeast Asia and offshore Australia, and are constructing three ultra-deepwater drillships and two high-specification jackups for delivery in fiscal years 2013 through 2015. We were founded in 1968 and are headquartered in Houston, Texas with support offices in Australia, Malaysia, Singapore and the United Kingdom.

During our 44 year history, the majority of our drilling units have operated outside of United States waters, and we have conducted drilling operations in most of the major offshore exploration areas of the world. At least 95% of our contract revenues were derived from foreign operations in each of the prior three fiscal years. However, as a result of our newest ultra-deepwater, semisubmersible drilling rig, the Atwood Condor, starting its initial contract in the U.S. Gulf of Mexico, we expect the percentage of our contract revenues derived from foreign operations for future fiscal years to decrease. For information relating to the contract revenues and long-lived assets attributable to specific geographic areas of operations, see Note 15 of the Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

We report our offshore contract drilling operation as a single reportable segment: Offshore Contract Drilling Services. The mobile offshore drilling units and related equipment comprising our offshore rig fleet operate in a single, global market for contract drilling services and are often redeployed globally due to changing demands of our customers, which consist largely of major integrated oil and natural gas companies and independent oil and natural gas companies.

The following table presents our rig fleet as of November 1, 2012, all of which are wholly owned:

Rig Name	Rig Type	Construction Completed/Last Upgraded (Calendar Year)	Water Depth Rating (feet)
Atwood Condor	Semisubmersible	construction completed 2012	10,000
Atwood Osprey	Semisubmersible	construction completed 2011	8,200
Atwood Eagle	Semisubmersible	upgraded 2002	5,000
Atwood Falcon	Semisubmersible	upgraded 2012	5,000
Atwood Hunter	Semisubmersible	upgraded 2001	5,000
Atwood Mako	Jackup	construction completed 2012	400
Atwood Beacon	Jackup	construction completed 2003	400
Atwood Aurora	Jackup	construction completed 2009	350
Vicksburg	Jackup	upgraded 1998	300
Atwood Southern Cross(1)	Semisubmersible	upgraded 2006	2,000
Seahawk(1)	Semisubmersible Tender Assist	upgraded 2006	1,800

(1) Currently cold-stacked and not actively marketed.

In addition to the above drilling units, we are in the process of constructing five additional drilling units. The following table presents our current newbuild projects as of November 1, 2012:

Rig Name	Rig Type	Shipyard	Expected Delivery Date	Expected Cost (in millions)	Water Depth Rating (feet)
Atwood Advantage	Drillship	Daewoo Shipbuilding and Marine Engineering Co., Ltd. (“DSME”)	September 30, 2013	$ 635	12,000
Atwood Achiever	Drillship	DSME	June 30, 2014	$ 635	12,000
Atwood Admiral	Drillship	DSME	March 31, 2015	$ 635	12,000
Atwood Manta	Jackup	PPL Shipyard PTE LTD	November 30, 2012	$ 190	400
Atwood Orca	Jackup	PPL Shipyard PTE LTD	June 30, 2013	$ 190	400

As of September 30, 2012, we had approximately $1.6 billion of estimated capital commitments primarily related to the construction of our five newbuild drilling units under construction. Included in this amount is a turnkey construction contract entered into in September 2012 with DSME to construct a third ultra-deepwater drillship, the Atwood Admiral, at the DSME yard in South Korea. The Atwood Admiral is expected to be delivered by March 31, 2015 at a total cost, including two blowout preventers ("BOPs"), project management, drilling and handling tools and spares, of approximately $635 million. The design of the Atwood Admiral will be substantially identical to the previously ordered Atwood Advantage and Atwood Achiever and will be a DP-3 dynamically-positioned, dual derrick ultra-deepwater drillship rated to operate in water depths up to 12,000 feet and drill to a depth of 40,000 feet. The Atwood Admiral will also offer two seven-ram BOPs, three 100-ton knuckle boom cranes, a 165-ton active heave "tree-running" knuckle boom crane, and accommodations for up to 200 persons.

Maintaining high equipment utilization and revenue efficiency through the industry cycles is a significant factor in generating cash flow to satisfy current and future obligations and has been one of our primary performance excellence initiatives. We had a 100% utilization rate in fiscal year 2012 for our in-service rigs, while our utilization rate for in-service rigs averaged approximately 95% during the past 10 fiscal years. As of November 1, 2012 our nine actively marketed in-service rigs had approximately 91% and 40% of our available rig days contracted for fiscal years 2013 and 2014, respectively. The Atwood Southern Cross and Seahawk are currently cold-stacked and not actively marketed.

The following table presents information regarding the contract status of our drilling units as of November 1, 2012:

Rig Name	Percentage of FY 2012 Revenues	Location at November 1, 2012	Customer	Contract Status at November 1, 2012
ULTRA-DEEPWATER SEMISUBMERSIBLES AND DRILLSHIPS				
Atwood Advantage	N/A	N/A	Noble Energy Inc. ("Noble")	Under construction in South Korea with expected delivery in September 2013. Upon delivery from the shipyard, the rig will mobilize to the Eastern Mediterranean Sea to commence a drilling program which extends to December 2016.
Atwood Achiever	N/A	N/A	None	Under construction in South Korea with expected delivery in June 2014.
Atwood Admiral	N/A	N/A	None	

				Under construction in South Korea with expected delivery in March 2015.
Atwood Condor	4.5%	U.S. Gulf of Mexico	Hess Corporation ("Hess")	The rig is currently working under a drilling program with Hess which extends to July 2014.
Atwood Osprey	22%	Offshore Australia	Chevron Australia Pty. Ltd. ("Chevron Australia")	The rig is currently working under a drilling program with Chevron Australia which extends to May 2017.

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DEEPWATER SEMISUBMERSIBLES				
Atwood Eagle	17%	Offshore Australia	Chevron Australia	The rig is currently working under a drilling program with Chevron Australia which extends to late November 2012. Upon completion of the drilling program with Chevron Australia, the rig will incur approximately one month of zero rate days for regulatory inspection and planned maintenance. Following this, the rig will commence a drilling program offshore Australia which extends to June 2014.
Atwood Falcon	13%	Offshore Australia	Apache Energy Ltd. ("Apache")	The rig is currently working under a drilling program with Apache with extends to November 2014.
Atwood Hunter	25%	Offshore Equatorial Guinea	Noble	The rig is currently working under a drilling program with Noble offshore West Africa which extends to September 2013.
JACKUPS				
Atwood Manta	N/A	N/A	CEC International, Ltd. ("CEC")	The rig is under construction in Singapore with expected delivery in November 2012. Upon delivery from the shipyard, the rig will mobilize to Thailand to commence a drilling program which extends to December 2013.
Atwood Orca	N/A	N/A	None	The rig is under construction in Singapore with expected delivery in June 2013.
Atwood Aurora	7%	Offshore Cameroon	Bowleven Plc. ("Bowleven")	The rig is currently under a drilling program for Bowleven offshore West Africa which extends to January 2013. Upon completion of the drilling program with Bowleven, the rig will commence a drilling program offshore Cameroon which extends to August 2013.
Atwood Beacon	6.5%	Eastern Mediterranean Sea	Shemen Oil and Gas Resources Ltd.	The rig is currently working under a drilling program with

			("Shemen")	Shemen which extends to April 2013.
Atwood Mako	0.5%	Offshore Thailand	Salamander Energy (Bualuang) Limited ("Salamander")	The rig is currently working under a drilling program with Salamander which extends to September 2013.
Vicksburg	4.5%	Offshore Thailand	CEC	The rig is currently working under a drilling program for CEC offshore Thailand which extends to December 2013.
OTHER				
Atwood Southern Cross	N/A	Malta	None	The rig is currently cold-stacked and is not being actively marketed.
Seahawk	N/A	Ghana	None	The rig is currently cold-stacked and is not being actively marketed.

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Our contract backlog at September 30, 2012 was approximately $2.6 billion, representing an approximate 73% increase compared to our contract backlog of $1.5 billion at September 30, 2011. See Item 1A. “Risk Factors—Our current backlog of contract drilling revenue may not be ultimately realized” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Market Outlook—Contract Backlog” in Item 7 of this Form 10-K.

OFFSHORE DRILLING EQUIPMENT

Each type of drilling rig is uniquely designed for different purposes and applications, for operations in different water depths, bottom conditions, environments and geographical areas, and for different drilling and operating requirements. We classify rigs with the ability to operate in 5,000 feet of water or greater as deepwater rigs and rigs with the ability to operate in 7,500 feet of water or greater as ultra-deepwater rigs. The following descriptions of the various types of drilling rigs we own or are constructing illustrate the diversified range of applications of our rig fleet.

Ultra-Deepwater Drillships. Drillships are generally self-propelled vessels, shaped like conventional ships, and are the most mobile of the major rig types. Our high-specification drillships currently under construction are dynamically positioned, which allows them to maintain position without anchors through the use of their onboard propulsion and station-keeping systems. Drillships typically have greater load capacity than semisubmersible rigs, which enables them to carry more supplies on board, often making them better suited for drilling in remote locations where resupply is more difficult. Drillships are a subset of floating rigs or floaters.

Semisubmersible Rigs. Each semisubmersible drilling unit has two hulls, the lower of which is capable of being flooded. Drilling equipment is mounted on the main hull. After the drilling unit is towed to location, the ballast tanks in the lower hull are flooded, lowering the entire drilling unit to its operating draft, and the drilling unit is either anchored in place (conventionally moored drilling unit) or maintains position without anchors through the use of onboard propulsion and station-keeping systems (dynamically positioned drilling unit). On completion of operations, the lower hull is deballasted, raising the entire drilling unit to its towing draft. Similar to drillships, this type of drilling unit is designed to operate in greater water depths than bottom supported drilling rigs. Semisubmersibles also operate in more severe sea conditions than other types of drilling units. Semisubmersible rigs are a subset of floating rigs or floaters.

Jackup Drilling Rigs. A jackup drilling rig consists of a single hull supported by three legs positioned on the sea floor. It is typically towed to the well site on its single hull. Once on location, legs are lowered to the sea floor and the unit is raised out of the water by jacking the hull up the legs.

Semisubmersible Tender Assist Rigs. Semisubmersible tender assist rigs operate like semisubmersible rigs except that their drilling equipment is temporarily installed on permanently constructed offshore support platforms. Semisubmersible tender assist rigs provide crew accommodations, storage facilities and other support for drilling operations.

INDUSTRY TRENDS

Our industry is subject to intense price competition and volatility. Periods of high demand and higher day rates are often followed by periods of low demand and lower day rates. Offshore drilling contractors can build new drilling rigs, mobilize rigs from one region of the world to another, “idle” or scrap rigs (taking them out-of-service) or reactivate idled rigs in order to adjust the supply of existing equipment in various markets to meet demand. The market for drilling services is typically driven by global hydrocarbon demand and changes in actual or anticipated oil and gas prices. Generally, sustained high energy prices translate into increased exploration and production spending by oil and gas companies, which in turn results in increased drilling activity and demand for equipment like ours.

Our customers are increasingly demanding newer, higher specification drilling rigs to perform contract drilling services either as a response to increased technical challenges or for the safety, reliability and efficiency typical of the newer, more capable rigs. This trend is commonly referred to as the bifurcation of the drilling fleet. Bifurcation is occurring in both the jackup and floater rig classes and is evidenced by the higher specification drilling rigs operating at generally higher overall utilization levels and day rates than the lower specification or standard drilling rigs. The lower specification class is also experiencing a significant number of rigs being either warm or cold-stacked or scrapped.

Floating drilling rigs are outfitted with highly sophisticated subsea well control equipment. The number of original equipment manufacturer (“OEM”) vendors manufacturing and servicing this equipment is limited and their ability to service the drilling industry on a timely basis is becoming challenging. Demand for service personnel has sharply increased and delivery times for this equipment are being lengthened, driven by the recent significant increase in the number of rigs under construction, related demand for new BOPs and the post-Macondo requirement by the Bureau of Ocean Energy Management (“BOEM”) that only OEM vendors service and/or recertify BOPs and other well control equipment.

The offshore drilling markets where we currently operate, including the U.S. Gulf of Mexico, the Mediterranean Sea, offshore West Africa, offshore Southeast Asia and offshore Australia are rich in hydrocarbon deposits and thus offer the potential for high rig utilization over the long-term. In addition, deepwater drilling activity in the U.S. Gulf of Mexico is returning to pre-Macondo levels, as evidenced by the number of drilling permits approved in recent months and the number of rigs currently operating in the region.

Current market activity is robust despite concerns of slowing global economies. Commodity prices have been relatively stable over the past year at levels which promote continued investment in exploration and development drilling globally.

DRILLING CONTRACTS

We obtain the contracts under which we operate our units either through direct negotiation with customers or by submitting proposals in competition with other contractors. Our contracts vary in their terms and rates depending on the nature of the operation to be performed, the duration of the work, the amount and type of equipment and services provided, the geographic areas involved, market conditions and other variables.

The initial term of contracts for our units has ranged from the length of time necessary to drill one well to several years. It is not unusual for contracts to contain renewal provisions, which in time of weak market conditions are usually at the option of the customer, and in strong market conditions are usually mutually agreeable.

Generally, contracts for drilling services specify a basic rate of compensation computed on a day rate basis. Contracts generally provide for a reduced day rate payable when operations are interrupted by equipment failure and subsequent repairs, field moves, adverse weather conditions or other factors beyond our control. Some contracts also provide for revision of the specified day rates in the event of material changes in certain items of cost. Any period during which a rig is not earning a full operating day rate because of the above conditions or because the rig is idle and not on contract will have an adverse effect on operating profits. An over-supply of drilling rigs in any market area can adversely affect our ability to employ our drilling units in these market areas.

For long moves of drilling equipment, we may obtain from our customers either a lump sum or a day rate as mobilization compensation for expenses incurred during the period in transit. In a weaker market environment, we may not fully recover our relocation costs. However, in a stronger market environment, we are generally able to obtain full reimbursement of relocation costs plus a partial or full day rate as mobilization compensation. We can give no assurance that we will receive full or partial recovery of any future relocation costs beyond that for which we have already contracted.

Certain of our contracts may be canceled upon specified notice at the option of the customer upon payment of an early termination payment. Contracts also customarily provide for either automatic termination or termination at the option of the customer in the event of total loss of the drilling rig, if a rig is not delivered to the customer, if a rig does not pass acceptance testing within the period specified in the contract, if drilling operations are suspended for extended periods of time by reason of excessive rig downtime for repairs, or other specified conditions, including force majeure or failure to meet minimum performance criteria. Early termination of a contract may result in a rig being idle for an extended period of time. Not all of our contracts require the customer to fully compensate us for the loss of the contract.

Operation of our drilling equipment is subject to the offshore drilling requirements of petroleum exploration companies and agencies of local or foreign governments. These requirements are, in turn, subject to changes in government policies, world demand and prices for petroleum products, proved reserves in relation to such demand and the extent to which such demand can be met from onshore sources.

The majority of our contracts are denominated in U.S. dollars, but occasionally a portion of a contract is payable in local currency. To the extent there is a local currency component in a contract, we attempt to match revenue in the local currency to operating costs paid in the local currency such as local labor, shore base expenses, and local taxes, if any.

INSURANCE AND RISK MANAGEMENT

Our operations are subject to the usual hazards associated with the drilling of oil and gas wells, such as blowouts, explosions and fires. In addition, our equipment is subject to various risks particular to our industry which we seek to mitigate by maintaining insurance. These risks include, among others, leg damage to jackups during positioning, capsizing, grounding, collision and damage from severe weather conditions. Any of these risks could result in damage or destruction of drilling rigs and oil and gas wells, personal injury and property damage, suspension of operations or environmental damage through oil spillage or extensive, uncontrolled fires. Therefore, in addition to general business insurance policies, we maintain the following insurance relating to our rigs and rig operations, among others: hull and machinery, protection and indemnity, mortgagee’s interest, cargo, war risks, casualty and liability (including excess liability) and, in certain instances, we may carry loss of hire. Our casualty and liability insurance policies are subject to self-insured deductibles. With respect to hull and machinery, we generally maintain a deductible of $5 million per occurrence. For general and marine third-party liabilities, we generally maintain a $1 million per occurrence deductible on personal injury liability for crew claims. Our rigs are insured at values ranging from book value, for the cold-stacked rigs, to estimated market value, for our in-service rigs. In addition, the Atwood Condor is insured against up to $150 million of damage as a result of a U.S. Gulf of Mexico windstorm.

As a result of significant losses incurred by the insurance industry due to offshore drilling rig accidents, such as the April 2010 Macondo incident in the U.S. Gulf of Mexico, damages from hurricanes such as Hurricane Ike in 2008, and other events, we have experienced modest increases in premiums for certain types of insurance coverage. Although we believe that we are adequately insured against normal and foreseeable risks in our operations in accordance with industry standards, such insurance may not be adequate to protect us against liability from all consequences of well disasters, marine perils, extensive fire damage, damage to the environment or disruption due to terrorism. To date, we have not experienced difficulty in obtaining insurance coverage, although we can provide no assurance as to the future availability of such insurance or the cost thereof. The occurrence of a significant event against which we are not adequately insured could have a material adverse effect on our financial position. See "Operating hazards increase our risk of liability; we may not be able to fully insure against all of these risks." in Item 1A. "Risk Factors" of this Form 10-K.

CUSTOMERS

During fiscal year 2012, we performed operations for 16 customers. Due to the relatively limited number of customers for which we can operate at any given time, revenues from three different customers amounted to 10% or more of our revenues in fiscal year 2012 as indicated below:

Customer	Percentage of Revenues	
Chevron Australia	34	%
Noble	17	%
Kosmos Energy Ghana Inc.	11	%

Our business operations are subject to the risks associated with a business having a limited number of customers for our products or services, and the loss of, or a decrease in the drilling programs of, these customers may adversely affect our revenues and, therefore, our results of operations and cash flows.

COMPETITION

The offshore drilling industry is very competitive, with no single offshore drilling contractor being dominant. We compete with a number of offshore drilling contractors for work, which varies by job requirements and location. Many of our competitors are substantially larger than we are and possess appreciably greater financial and other resources and assets than we do. Our competitors include, among others, the six members of our self-determined peer group including Diamond Offshore Drilling, Inc., Ensco plc, Noble Corporation, Rowan Companies, Inc., Seadrill Limited, and Transocean Ltd.

Technical capability, location, rig availability and price competition are generally the most important factors in the offshore drilling industry; however, when there is high worldwide utilization of equipment, rig availability and suitability become more important factors in securing contracts than price. Other competitive factors include work force experience, efficiency, condition of equipment, safety performance, reputation and customer relations. We believe that we compete favorably with respect to these factors.

INTERNATIONAL OPERATIONS

During our history, we have operated in most of the major offshore exploration areas of the world. At least 95% of our contract revenues were derived from foreign operations in each of the prior three fiscal years. However, as a result of our newest ultra-deepwater, semisubmersible drilling rig, the Atwood Condor, currently in the U.S. Gulf of Mexico, we expect the percentage of our contract revenues derived from foreign operations for future fiscal years to decrease. Because of our experience in a number of geographic areas and the mobility of our equipment, we believe we are not dependent upon any one area for our long-term operations.

For information about risk associated with our foreign operations, see Item 1A, “Risk Factors—Our international operations may involve risks not generally associated with domestic operations.” and “A change in tax laws in any country in which we operate could result in higher tax expense” of this Form 10-K.

EMPLOYEES

As of November 1, 2012, we had approximately 1,460 personnel engaged, including through labor contractors or agencies. In connection with our foreign drilling operations, we are often required by the host country to hire a substantial percentage of our work force in that country and, in some cases, these employees are represented by foreign unions. To date, we have experienced little difficulty in complying with such requirements, and our drilling operations have not been significantly interrupted by strikes or work stoppages. Our success also depends to a significant extent upon the efforts and abilities of our executive officers and other key management personnel. There is no assurance that these individuals will continue in such capacity for any particular period of time.

ENVIRONMENTAL REGULATION

Our operations are subject to a variety of U.S. and foreign environmental regulation and to international environmental conventions. We monitor environmental regulation in each country in which we operate and, while we have experienced an increase in general environmental regulation, we do not believe compliance with such regulations will have a material adverse effect upon our business or results of operations. Past environmental issues, such as the Macondo incident, have led to higher drilling costs, a more difficult and lengthy well permitting process and, in general, have adversely affected decisions of oil and gas companies to drill in these areas.

In the United States, regulations applicable to our operations include regulations controlling the discharge of materials into the environment, requiring removal and cleanup of materials that may harm the environment, or otherwise relating to the protection of the environment. Laws and regulations protecting the environment have become more stringent, and may in some cases impose strict liability, rendering a person liable for environmental damage without regard to negligence or fault on the part of such person. Some of these laws and regulations may expose us to liability for the conduct of or conditions caused by others or for acts which were in compliance with all applicable laws at the time they were performed. The application of these requirements or the adoption of new requirements could have a material adverse effect on our financial position, results of operations or cash flows. We believe all of our rigs satisfy current environmental requirements and certifications, if any, required to operate in the jurisdictions where they currently operate, but can give no assurance that in the future they will satisfy new environmental requirements or certifications, if any, or that the costs to satisfy such requirements or certifications, if any, would not materially affect our financial position, results of operations or cash flows. As a result of the Macondo incident, there is pending legislation which, if enacted, would likely affect liability limits under existing U.S. environmental laws and regulations. If and when such proposed legislation is enacted, we will be able to better assess its impact on us. The description below of U.S. environmental laws and regulations is based upon those currently in effect.

The U.S. Federal Water Pollution Control Act of 1972, commonly referred to as the Clean Water Act, prohibits the discharge of specified substances into the navigable waters of the United States without a permit. The regulations implementing the Clean Water Act require permits to be obtained by an operator before specified exploration activities occur. Offshore facilities must also prepare plans addressing spill prevention control and countermeasures. Violations of monitoring, reporting and permitting requirements can result in the imposition of administrative, civil and criminal penalties.

The U.S. Oil Pollution Act of 1990, or OPA, and related regulations impose a variety of requirements on “responsible parties” related to the prevention of oil spills and liability for damages resulting from such spills. Few defenses exist to the strict liability imposed by OPA, and the liability could be substantial. Failure to comply with ongoing requirements or inadequate cooperation in the event of a spill could subject a responsible party to civil or criminal enforcement action. OPA assigns joint and several, strict liability, without regard to fault, to each liable party for all containment and oil removal costs and a variety of public and private damages including, but not limited to, the costs of responding to a release of oil, natural resource damages, and economic damages suffered by persons adversely affected by an oil spill.

The U.S. Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, also known as the “Superfund” law, imposes liability without regard to fault or the legality of the original conduct on some classes of persons that are considered to have contributed to the release of a “hazardous substance” into the environment. Such persons include the owner or operator of a facility where a release occurred and companies that disposed of or arranged for the transport or disposal of the hazardous substances found at a particular site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liabilities for the cost of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the U.S. Environmental Protection Agency (the "EPA") and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is also not uncommon for third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances.

The U.S. Resource Conservation and Recovery Act (“RCRA”), and similar state and local laws and regulations govern the management of wastes, including the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements, and liability for failure to meet such requirements, on a person who is either a “generator” or “transporter” of hazardous waste or an “owner” or “operator” of a hazardous waste treatment, storage or disposal facility. RCRA specifically excludes from the definition of hazardous waste drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil and natural gas. A similar exemption is contained in many of the state counterparts to RCRA, leaving them to be regulated as solid waste. As a result, a substantial portion of RCRA's requirements do not apply as our operations generate minimal quantities of hazardous wastes (i.e., industrial wastes such as solvents, waste compressor oils, etc.). However, a petition is currently before the EPA to revoke the oil and natural gas exploration and production exemption. Any repeal or modification of this or similar exemption in similar state statutes, would increase the volume of hazardous waste we are required to manage and dispose of, and would cause us, as well as our competitors, to incur increased operating expenses with respect to our U.S. operations.

OTHER GOVERNMENTAL REGULATION

Our operations are subject to various international conventions, laws and regulations in the countries in which we operate, including laws and regulations relating to the importation of and operation of drilling units, currency conversions and repatriation, oil and gas exploration and development, taxation of offshore earnings and earnings of expatriate personnel, environmental protection, the use of local employees and suppliers by foreign contractors and duties on the importation and exportation of drilling units and other equipment. Governments in some foreign countries have become increasingly active in regulating and controlling the ownership of concessions and companies holding concessions, the exploration for oil and gas and other aspects of the oil and gas industries in their countries. In some areas of the world, this governmental activity has adversely affected the amount of exploration and development work done by major oil and gas companies and may continue to do so. Operations in less developed countries can be subject to legal systems that are not as mature or predictable as those in more developed countries, which can lead to greater uncertainty in legal matters and proceedings.

Our newest active ultra-deepwater, semisubmersible drilling rig, the Atwood Condor, is currently in the U.S. Gulf of Mexico under contract with Hess Corporation as of the fourth quarter of fiscal year 2012 and, at this time, is our only rig in the U.S. Our U.S. operations are subject to various U.S. laws and regulations, including the new drilling safety rules and workplace safety rules set forth by the BOEM and the Bureau of Safety and Environmental Enforcement (“BSEE”), which are designed to improve drilling safety by strengthening requirements for safety equipment, well control systems, and blowout prevention practices on offshore oil and gas operations, and improve workplace safety by reducing the risk of human error. Implementation of new BOEM or BSEE guidelines or regulations may subject us to increased costs or limit the operational capabilities of our U.S. based rigs and could materially and adversely affect our financial position, results of operations or cash flows. Please see Item 1A. “Risk Factors — Government regulation and environmental risks could reduce our business opportunities and increase our costs” of this Form 10-K.

We believe we are in compliance in all material respects with the health, safety and other regulations affecting the operation of our rigs and the drilling of oil and gas wells in the jurisdictions in which we operate. Historically, we have made significant capital expenditures and incurred additional expenses to ensure that our equipment complies with applicable local and international health and safety regulations. Although such expenditures may be required to comply with these governmental laws and regulations, such compliance has not, to date, materially adversely affected our earnings, cash flows or competitive position.

AVAILABLE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. Our SEC filings are available to the public over the internet at the SEC’s web site at http://www.sec.gov. Our website address is www.atwd.com. We make available free of charge on or through our website our annual report on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. We have adopted a Code of Business Conduct and Ethics and a Code of Ethics for the Chief Executive Officer and Senior Financial Officers which are available on our website. We intend to satisfy the disclosure requirement regarding any changes in or waivers from our codes of ethics by posting such information on our website or by filing a Form 8-K for such event. Unless stated otherwise, information on our website is not incorporated by reference into this report or made a part hereof for any purpose. You may also read and copy any document we file at the SEC's Public Reference Room at 100 F Street NE, Washington, DC 20549. Please call the SEC at 1-800-SEC-0330 for further information on the Public Reference Room and copy charges.

ITEM 1A. RISK FACTORS

You should carefully consider the following risk factors in addition to the other information included in this Form 10-K. These risks and uncertainties may affect our business, financial position, results of operations or cash flows, as well as an investment in our common stock.

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

Our business depends on the conditions of the 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;
- 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
- environmental and other laws and governmental regulations regarding exploration and development of oil and natural gas reserves.

The level of 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 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 and, therefore, could have a material adverse effect on our financial position, results of operations and cash flows.

Our industry is subject to intense price competition and volatility.

The contract drilling business is highly competitive with numerous industry participants. Drilling contracts are traditionally awarded on a competitive bid basis. Price competition is often the primary factor in determining which qualified contractor is awarded a job, although rig availability, the quality and technical capability of service and equipment and safety record are also factors. We compete with a number of offshore drilling contractors, many of which are substantially larger than we are and which possess appreciably greater financial and other resources and assets than we do.

The industry in which we operate historically has been volatile, marked by periods of low demand, excess rig supply and low day rates, followed by periods of high demand, low rig availability and increasing day rates. Periods of excess rig supply intensify the competition in the industry and often result in rigs being idled. We may be required to idle additional rigs or to enter into lower-rate contracts in response to market conditions in the future. Presently, there are numerous recently constructed ultra-deepwater vessels and high-specification jackups that have entered the market and more are under contract for construction. Many of these units do not have drilling contracts in place. The entry into service of these new units has increased and will continue to increase rig supply and could curtail a strengthening, or trigger a reduction, in day rates and utilization as rigs are absorbed into the active fleet. Any further increase in construction of new units may increase the negative impact on day rates and utilization. In addition, rigs may be relocated to markets in which we operate, which could result in or exacerbate excess rig supply which may lower day rates in those markets.

Lower utilization and day rates in one or more of the regions in which we operate would adversely affect our revenues and profitability. Prolonged periods of low utilization and day rates could also result in the recognition of impairment charges on certain of our drilling rigs if future cash flow estimates, based upon information available to management at the time, indicate that the carrying value of these rigs may not be recoverable.

Our business relies heavily on a limited number of customers and a limited number of drilling units and the loss of a significant customer, the loss of a rig, or significant downtime for our rigs could materially and adversely impact our business.

Our customer base includes a small number of major and independent oil and gas companies as well as government-owned oil companies. In fiscal year 2012, three customers each accounted for over 10% of our operating revenues: Chevron Australia, 34%; Noble, 17%; and Kosmos Energy Ghana Inc., 11%. The contract drilling business is subject to the usual risks associated with having a limited number of customers for our services. Further, consolidation among oil and natural gas exploration and production companies may reduce the number of available customers. Our business and results of operations could be materially and adversely affected if any of our major customers terminate their contracts with us, fail to renew our existing contracts, refuse to award new contracts to us or experience difficulties in obtaining financing to fund their drilling programs. In addition, we currently have only 11 drilling units, and only nine of which are currently in operation and actively marketed. As a result, if any one or more of our drilling units were idled for a prolonged period of time, our business and results of operations could be materially and adversely affected.

High levels of capital expenditures will be necessary to keep pace with the bifurcation of the drilling fleet.

The market for our services is characterized by continual and rapid 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 for both the jackup and floater rig classes and is evidenced by the higher specification drilling rigs generally operating at higher overall utilization levels and day rates than the lower specification or standard drilling rigs. In addition, a significant number of lower specification rigs are being stacked. As a result of this bifurcation, a high 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.

If we are not successful in acquiring or building new rigs and equipment or upgrading our existing rigs and equipment in a timely and cost-effective manner, we could lose market share. In addition, current competitors or new market entrants may develop new technologies, services or standards that could render some of our services or equipment obsolete, which could have a material adverse effect on our operations.

Rig upgrade, repair and construction projects are subject to risks, including delays, cost overruns, and failure to secure drilling contracts.

As of November 1, 2012, we had three ultra-deepwater drillships and two high-specification jackup rigs under construction. Three of our five newbuilds currently under construction do not have long-term drilling contracts in place. We may also commence the construction of additional rigs for our fleet from time to time without first obtaining drilling contracts covering any such rig. Our failure to secure drilling contracts for rigs under construction, including our remaining uncontracted newbuild construction projects, prior to deployment could adversely affect our financial position, results of operations or cash flows.

Since 2009, we have invested or committed to invest over $3.9 billion in the expansion of our fleet, including ultra-deepwater and jackup rigs. Depending on available opportunities, we may construct additional rigs for our fleet in the future. In addition, we incur significant upgrade, refurbishment and repair expenditures on our fleet from time to time. Some of these expenditures are unplanned. These projects are subject to risks of delay or cost overruns inherent in any large construction project resulting from numerous factors, including the following:

- shortages of equipment, materials or skilled labor;
- unscheduled delays in the delivery of ordered materials and equipment;

- unanticipated increases in the cost of equipment, labor and raw materials, particularly steel;
- weather interferences;
- difficulties in obtaining necessary permits or in meeting permit conditions;

- design and engineering problems;
- client acceptance delays;
- political, social and economic instability, war and civil disturbances;
- delays in customs clearance of critical parts or equipment;
- financial or other difficulties or failures at shipyards and suppliers;
- disputes with shipyards and suppliers; and
- work stoppages and other labor disputes.

Delays in the delivery of rigs being constructed or undergoing upgrade, refurbishment or repair may result in delay in contract commencement, resulting in a loss of revenue to us, and may cause our customers to seek to terminate or shorten the terms of their contract under applicable late delivery clauses, if any. In the event of termination of one of these contracts, we may not be able to secure a replacement contract on as favorable terms, if at all. The estimated capital expenditures for rig upgrades, refurbishments and construction projects could materially exceed our planned capital expenditures. Moreover, our rigs undergoing upgrade, refurbishment and repair may not earn a day rate during the period they are out-of-service.

Our business may experience reduced profitability if our customers terminate or seek to renegotiate our drilling contracts.

Currently, our contracts with customers are day rate contracts, in which we charge a fixed amount per day regardless of the number of days needed to drill the well. During depressed market conditions, a customer may no longer need a rig that is currently under contract or may be able to obtain a comparable rig at a lower day rate. Customers may seek to renegotiate the terms of their existing drilling contracts or avoid their obligations under those contracts. In addition, certain of our contracts may be cancelled upon specified notice at the option of the customer upon payment of an early termination payment. Contracts also customarily provide for either automatic termination or termination at the option of the customer in the event of total loss of the drilling rig, if a rig is not delivered to the customer, if a rig does not pass acceptance testing within the period specified in the contract, if drilling operations are suspended for extended periods of time by reason of excessive rig downtime for repairs, or other specified conditions, including force majeure or failure to meet minimum performance criteria. Early termination of a contract may result in a rig being idle for an extended period of time. Not all of our contracts require the customer to fully compensate us for the loss of the contract. Our revenues may be adversely affected by customers’ early termination of contracts, especially if we are unable to re-contract the affected rig within a short period of time. The termination or renegotiation of a number of our drilling contracts could adversely affect our financial position, results of operations and cash flows.

Our business will be adversely affected if we are unable to secure contracts on economically favorable terms.

The drilling markets in which we compete frequently experience significant fluctuations in the demand for drilling services, as measured by the level of exploration and development expenditures, and the supply of capable drilling equipment. We have four contracts that will expire during fiscal year 2013 with no immediate follow-on work currently scheduled. Our ability to renew these contracts or obtain new contracts and the terms of any such contracts will depend on market conditions. We may be unable to renew our expiring contracts or obtain new contracts for the rigs under contracts that have expired or been terminated, and the day rates under any new contracts may be substantially below the existing day rates, which could materially reduce our revenues and profitability. We can, as we have done in the past, relocate drilling rigs from one geographic area to another, but only when such moves are economically justified, or we can idle rigs temporarily to save operating expenses and reduce rig supply. If demand for our rigs declines, rig utilization and day rates are generally adversely affected, which in turn, would adversely affect our revenues.

Our current backlog of contract drilling revenue may not be ultimately realized.

As of September 30, 2012, our contract drilling backlog was approximately $2.6 billion for future revenues under firm commitments. We 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. In addition, some of our customers could experience liquidity issues or could otherwise be unable or unwilling to perform under the contract, which could ultimately lead a customer to go into bankruptcy or to otherwise encourage a customer to seek to repudiate, cancel or renegotiate a contract. Our inability or the inability of our customers to

perform under our or their contractual obligations may have a material adverse effect on our financial position, results of operations and cash flows.
Our customers may be unable or unwilling to indemnify us.
Consistent with standard industry practice, we typically obtain contractual indemnification from our customers whereby

they agree to protect and indemnify us for liabilities resulting from various hazards associated with the drilling industry. We can provide no assurance, however, that our customers will be willing or financially able to meet these indemnification obligations. Also, we may choose not to enforce these indemnities because of business reasons.

Operating hazards increase our risk of liability; we may not be able to fully insure against all of these risks.

Our operations are subject to various operating hazards and risks, including:

- well blowouts, loss of well control and reservoir damage;
- fires and explosions;
- catastrophic marine disaster;
- adverse sea and weather conditions;
- mechanical failure;
- navigation errors;
- collision;
- oil and hazardous substance spills, containment and clean up;
- lost or stuck drill strings;
- equipment defects;
- labor shortages and strikes;
- damage to and loss of drilling rigs and production facilities; and
- war, sabotage, terrorism and piracy.

These risks present a threat to the safety of personnel and to our rigs, cargo, equipment under tow and other property, as well as the environment. Our operations and those of others could be suspended as a result of these hazards, whether the fault is ours or that of a third party. In certain circumstances, governmental authorities may suspend drilling operations as a result of these hazards, and our customers may cancel or terminate their contracts. Third parties may have significant claims against us for damages due to personal injury, death, property damage, pollution and loss of business if such event were to occur in our operations.

Our offshore drilling operations are also subject to marine hazards, either at offshore sites or while drilling equipment is under tow, such as vessel capsizings, sinkings, collisions or groundings. In addition, raising and lowering jackup drilling rigs, flooding semisubmersible ballast tanks and drilling into high-pressure formations are complex, hazardous activities, and we can encounter problems.

We have had accidents in the past due to some of the hazards described above. Because of the ongoing hazards associated with our operations:

- we may experience accidents;
- our insurance coverage may prove inadequate to cover our losses;
- our insurance deductibles may increase; or
- our insurance premiums may increase to the point where maintaining our current level of coverage is prohibitively expensive or we may be unable to obtain insurance at all.

We maintain insurance coverage against casualty and liability risks and have renewed our primary insurance program through June 30, 2013. Certain risks, however, such as pollution, reservoir damage and environmental risks generally are not fully insurable. Although we believe our insurance is adequate, our policies and contractual indemnity rights may not adequately cover all losses or may have exclusions of coverage for certain losses. We do not have insurance coverage or rights to indemnity for all risks. In addition, we may be unable to renew or maintain our existing insurance coverage at commercially reasonable rates or at all. If a significant accident or other event occurs and is not fully covered by insurance or contractual indemnity, it could adversely affect our financial position, results of operations or cash flows. There is no assurance that our insurance coverage will be available or affordable and, if available, whether it will be adequate to cover future claims that may arise. Additionally, there is no assurance that those parties with contractual obligations to indemnify us will necessarily be financially able or willing to indemnify us against all these risks.

Our drilling contracts provide for varying levels of indemnification from our customers and in most cases may require us to indemnify our customers. Under offshore drilling contracts, liability with respect to personnel and property is customarily assigned on a “knock-for-knock” basis, which means that we and our customers assume liability for our respective personnel and property. However, in certain cases we may have liability for damage to our customer’s property and other third-party property on the rig. Our customers typically assume responsibility for and indemnify us from any loss or liability resulting from pollution or contamination, including clean-up and removal and third-party damages, arising from operations under the contract and originating below the surface of the water, including as a result of blow-outs or cratering of the well. In some drilling contracts, however, we may have liability for third-party damages resulting from such pollution or contamination caused by our gross negligence, or, in some cases, ordinary negligence, subject to negotiated caps. We generally indemnify the customer for legal and financial consequences of spills of industrial waste and other liquids originating from our rigs or equipment above the surface of the water.

The above description of our insurance program and the indemnification provisions of our drilling contracts is only a summary and is general in nature. Our insurance program and the terms of our drilling contracts may change in the future. In addition, the indemnification provisions of our drilling contracts may be subject to differing interpretations, and enforcement of those provisions may be limited by public policy and other considerations.

Our long-term contracts are subject to the risk of cost increases, which could adversely impact our profitability.

In periods of rising demand for offshore rigs, a drilling contractor generally would prefer to enter into well-to-well or other short-term contracts less than one year in duration that would allow the contractor to profit from increasing day rates, while customers with reasonably definite drilling programs would typically prefer long-term contracts in order to maintain day rates at a consistent level. Conversely, in periods of decreasing demand for offshore rigs, a drilling contractor generally would prefer long-term contracts to preserve day rates and utilization, while customers generally would prefer well-to-well or other short-term contracts that would allow the customer to benefit from the decreasing day rates. For the fiscal year ended September 30, 2012, a majority of our revenue was derived from long-term day rate contracts greater than one year in duration, and substantially all of our backlog as of September 30, 2012 was attributable to long-term day rate contracts. As a result, our inability to fully benefit from increasing day rates in an improving market may limit our profitability.

In general, our costs increase as the business environment for drilling services improves and demand for oilfield equipment and skilled labor increases. While many of our contracts include cost escalation provisions that allow changes to our day rate based on stipulated cost increases or decreases, the timing and amount earned from these day rate adjustments may differ from our actual increase in costs. Additionally, if our rigs incur idle time between contracts, we typically do not remove personnel from those rigs because we utilize the crew to prepare the rig for its next contract. During times of reduced activity, reductions in costs may not be immediate as portions of the crew may be required to prepare our rigs for stacking, after which time the crew members are assigned to active rigs or dismissed. Moreover, as our rigs are mobilized from one geographic location to another, the labor and other operating and maintenance costs can vary significantly. In general, labor costs increase primarily due to higher salary levels and inflation. Equipment maintenance expenses fluctuate depending upon the type of activity the unit is performing and the age and condition of the equipment. Contract preparation expenses vary based on the scope and length of contract preparation required and the duration of the firm contractual period over which such expenditures are amortized.

A change in tax laws in any country in which we operate could result in higher tax expense.

We conduct our worldwide operations through various subsidiaries. Tax laws and regulations are highly complex and subject to interpretation. Consequently, we are subject to changing tax laws, treaties and regulations in and between countries in which we operate. Our income tax expense is based on our interpretation of the tax laws in effect at the time the expense was incurred. Tax legislation is proposed from time to time which could, among other things, limit our ability to defer the taxation of non-U.S. income and would increase current tax expense. A change in tax laws, treaties or regulations, or in the interpretation thereof, could result in a materially higher tax expense or a higher effective tax rate on our worldwide earnings.

We file periodic tax returns that are subject to review and audit by various revenue agencies in the jurisdictions in which we operate. Taxing authorities may challenge any of our tax positions. We are currently contesting tax assessments that could have a material impact on our financial statements and we may contest future assessments where we believe the assessments are in error. Determinations by such authorities that differ materially from our recorded estimates, favorably or unfavorably, may have a material impact on our financial position, results of operations or cash flows.

Government regulation and environmental risks could reduce our business opportunities and increase our costs.

We must comply with extensive government regulation in the form of international conventions, federal, state and local laws and regulations in jurisdictions where our vessels operate and are registered. These conventions, laws and regulations govern oil spills and matters of environmental protection, worker health and safety, and the manning, construction and operation of vessels, and vessel and port security. We believe that we are in material compliance with all applicable environmental, health and safety and vessel and port security laws and regulations as currently in effect. We are not a party to any pending governmental litigation or similar proceeding, and we are not aware of any threatened governmental litigation or proceeding which, if adversely determined, would have a material adverse effect on our financial position, results of operations or cash flows. However, failure to comply with these laws and regulations may result in the assessment of administrative, civil and even criminal penalties, the imposition of remedial obligations, the denial or revocation of permits or other authorizations and the issuance of injunctions that may limit or prohibit our operations. In addition, compliance with environmental, health and safety and vessel and port security laws increases our costs of doing business.

Environmental, health and safety and vessel and port security laws change frequently, and we may not be able to anticipate such changes or the impact of such changes. There is no assurance that we can avoid significant costs, liabilities and penalties imposed as a result of governmental regulation in the future. Changes in laws or regulations regarding offshore oil and gas exploration and development activities, the cost or availability of insurance, and decisions by customers, governmental agencies, or other industry participants could reduce demand for our services or increase our costs of operations, which could have a negative impact on our financial position, results of operations or cash flows, but we cannot reasonably or reliably estimate that such changes will occur, when they will occur, or if they will impact us. Such changes can occur quickly within a region, similar to the Macondo well incident in the U.S. Gulf of Mexico in April 2010, which may impact both the affected region and global utilization and day rates, and we may not be able to respond quickly, or at all, to mitigate such changes.

Failure to comply with the U.S. Foreign Corrupt Practices Act or foreign anti-bribery legislation could have an adverse impact on 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 effect on our business, financial position, results of operations or cash flows. 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 rigs or other assets.

Our international operations may involve risks not generally associated with domestic operations.

We derive a significant portion of our revenues from operations outside the United States. Our operations are subject to risks inherent in conducting business internationally, such as:

- legal and governmental regulatory requirements;
- difficulties and costs of staffing and managing international operations;
- political, social and economic instability;
- terrorist acts, piracy, war and civil disturbances;
- language and cultural difficulties;
- potential vessel seizure, expropriation or nationalization of assets or confiscatory taxation;
- import-export quotas or other trade barriers;
- renegotiation, nullification or modification of existing contracts;
- difficulties in collecting accounts receivable and longer collection periods;
- foreign and domestic monetary policies;
- work stoppages;
- complications associated with repairing and replacing equipment in remote locations;
- limitations on insurance coverage, such as war risk coverage, in certain areas;
- wage and price controls;
- assaults on property or personnel, including kidnappings;
- travel limitations or operational problems caused by public health or security threats;
- imposition of currency exchange controls;
- solicitation by governmental officials for improper payments or other forms of corruption;

- currency exchange fluctuations and devaluations; or,
- potentially adverse tax consequences, including those due to changes in laws or interpretation of existing laws.

Our non-U.S. operations are subject to various laws and regulations in certain countries in which we operate, including laws and regulations relating to the import and export, equipment and operation of drilling units, currency conversions and repatriation, oil and gas exploration and development, and taxation of offshore earnings and earnings of expatriate personnel. Governments in some foreign countries have become increasingly active in regulating and controlling the ownership of concessions and companies holding concessions, the exploration for oil and gas and other aspects of the oil and gas industries in their countries, including local content requirements for participating in tenders for certain drilling contracts. Many governments favor or effectively require the awarding of drilling contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. In addition, government action, including initiatives by OPEC, may continue to cause oil or gas price volatility. In some areas of the world, this governmental activity has adversely affected the amount of exploration and development work by major oil companies and may continue to do so. Operations in less developed countries can be subject to legal systems which are not as mature or predictable as those in more developed countries, which can lead to greater uncertainty in legal matters and proceedings.

Some of our drilling contracts are partially payable in local currency. Those amounts may exceed our local currency needs, leading to the accumulation of excess local currency, which, in certain instances, may be subject to either temporary blocking or other difficulties converting to U.S. dollars. Excess amounts of local currency may be exposed to the risk of currency exchange losses.

The shipment of goods, services and technology across international borders subjects us to extensive trade and other laws and regulations. Our import and export activities are governed by unique customs laws and regulations in each of the countries where we operate. Moreover, many countries, including the U.S., control the import and export of certain goods, services and technology and impose related import and export recordkeeping and reporting obligations, the laws and regulations related to which are complex and constantly changing. These laws and regulations may be enacted, amended, enforced or interpreted in a manner materially impacting our operations. Shipments may be delayed and denied import or export for a variety of reasons, some of which are outside our control, and such delays or denials could cause unscheduled operational downtime. Any failure to comply with these applicable legal and regulatory obligations also could result in criminal and civil penalties and sanctions, such as fines, imprisonment, debarment from government contracts, seizure of shipments and loss of import and export privileges.

In the past, these conditions or events have not materially affected our operations. However, we cannot predict whether any such conditions or events might develop in the future. Also, we organized our subsidiary structure and our operations, in part, based on certain assumptions about various foreign and domestic tax laws, currency exchange requirements, and capital repatriation laws. While we believe our assumptions are correct, there can be no assurance that taxing or other authorities will reach the same conclusion. If our assumptions are incorrect, or if the relevant countries change or modify such laws or the current interpretation of such laws, we may suffer adverse tax and financial consequences, including the reduction of cash flow available to meet required debt service and other obligations. Any of these factors could materially adversely affect our international operations and, consequently, our business, financial position, results of operations or cash flows.

Our business is subject to war, sabotage, terrorism and piracy, which could have an adverse effect.

It is unclear what impact the current United States military campaigns or possible future campaigns will have on the energy industry in general, or us in particular, in the future. Uncertainty surrounding retaliatory military strikes or a sustained military campaign may affect our operations in unpredictable ways, including changes in the insurance markets, disruptions of fuel supplies and markets, particularly oil, and the possibility that infrastructure facilities, including pipelines, production facilities, refineries, electric generation, transmission and distribution facilities, could be direct targets of, or indirect casualties of, an act of terror. War or risk of war may also have an adverse effect on the economy.

Acts of war, sabotage, terrorism, piracy and social unrest, brought about by world political events or otherwise, have caused instability in the world’s financial and insurance markets in the past and may continue to do so in the future. Such acts could be directed against companies such as ours, and could also adversely affect the oil, gas and power industries and restrict their future growth. Insurance premiums could increase and coverage may be unavailable in the future.

Failure to obtain and retain key personnel could impede our operations.

We depend to a significant extent upon the efforts and abilities of our executive officers and other key management personnel. There is no assurance that these individuals will continue in such capacity for any particular period of time. The loss of the services of one or more of our executive officers or other personnel could adversely affect our operations.

We require highly skilled personnel to operate our drilling rigs and provide technical services and support for our business worldwide. Historically, competition for the labor required for drilling operations and construction projects, has intensified as the number of rigs activated, added to worldwide fleets or under construction increased, leading to shortages of qualified personnel in the industry and creating upward pressure on wages and higher turnover. We may experience increased competition for the crews necessary to operate our rigs. If increased competition for labor were to intensify in the future, we may experience increases in costs or reductions in experience levels which could impact operations. The shortages of qualified personnel or the inability to obtain and retain qualified personnel could also negatively affect the quality, safety and timeliness of our work.

Consolidation of suppliers may limit our ability to obtain supplies and services at an acceptable cost, on our schedule or at all.

Our operations rely on a significant supply of capital and consumable spare parts and equipment to maintain and repair our fleet. We also rely on the supply of ancillary services, including supply boats and helicopters. Recent consolidation has reduced the number of available suppliers, resulting in fewer alternatives for sourcing of key supplies and services. We may not be able to obtain supplies and services at an acceptable cost, at the times we need them or at all. These cost increases, delays or unavailability could negatively impact our future operations and result in increases in rig downtime, and delays in the repair and maintenance of our fleet.

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

Certain of our employees and contractors in international markets are represented by labor unions and work under collective bargaining or similar agreements, which are subject to periodic renegotiation. 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.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas we produce.

There is a concern that emissions of greenhouse gases (“GHG”) may alter the composition of the global atmosphere in ways that affect the global climate. Climate change, including the impact of global warming, may create physical and financial risk. Physical risks from climate change include an increase in sea level and changes in weather conditions. Given the maritime nature of our business, we do not believe that physical climate change is likely to have a material adverse effect on us. Financial risks relating to climate change are likely to arise from increasing legislation and regulation, as compliance with any new rules could be difficult and costly.

United States federal legislation has been proposed in Congress to reduce GHG emissions and federal legislation limiting GHG emissions may be enacted in the United States. In addition, the EPA has undertaken new efforts to collect information regarding GHG emissions and their effects and has begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the federal Clean Air Act, one of which requires a reduction in emissions of GHGs from motor vehicles and the other of which established a permitting requirement for emissions of GHGs from certain large stationary sources, effective January 2, 2011. The EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States on an annual basis, as well as certain onshore and offshore oil and natural gas production facilities on an annual basis, beginning in 2012 for emissions occurring in 2011. Foreign jurisdictions are also addressing climate changes by legislation or regulation. The adoption of legislation and regulatory programs to reduce emissions of GHGs could require us to incur increased energy, environmental and other costs and capital expenditures to comply. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial position, results of operations or cash flows.

Adverse impacts upon the oil and gas industry relating to climate change may also affect us as demand for our services depends on the level of activity in offshore oil and natural gas exploration, development and production. Although we do not expect that demand for oil and gas will lessen dramatically over the short term, concerns about climate change may reduce the demand for oil and gas in the long term. In addition, increased regulation of GHG may create greater incentives for use of alternative energy sources. Any long term material adverse effect on the oil and gas industry may have a material adverse effect on our financial position, results of operations or cash flows, but we cannot reasonably or reliably estimate if it will occur, when it will occur or that it will impact us.

We are subject to anti-takeover provisions of our constitutive documents and Texas law.

Holders of the shares of an acquisition target often receive a premium for their shares upon a change of control. Texas law and provisions of constitutive documents could have the effect of delaying or preventing a change of control and could prevent holders of our common stock from receiving such a premium. For example, Texas law prohibits us from engaging in a

business combination with any shareholder for three years from the date that person became an affiliated shareholder by beneficially owning 20% or more of our outstanding common stock, in the absence of certain board of director or shareholder approvals.
In addition, under our By-laws, special meetings of shareholders may not be called by anyone other than our Board of Directors, the Chairman of the Board of Directors, our President and Chief Executive Officer, or the holders of at least 10% of the shares of our capital stock entitled to vote at such meeting.
Covenants in our debt agreements restrict our ability to engage in certain activities.
Our debt agreements restrict our ability to, among other things:
- incur, assume or guarantee additional indebtedness or issue certain stock;
- pay dividends or distributions or redeem, repurchase or retire our capital stock or subordinated debt;
- make loans and other types of investments;
- incur liens;
- restrict dividends, loans or asset transfers from our subsidiaries;
- sell or otherwise dispose of assets, including capital stock of subsidiaries;
- consolidate or merge with or into, or sell substantially all of our assets to, another person;
- acquire assets or businesses;
- enter into transactions with affiliates; and
- enter into new lines of business.

In addition, our revolving credit facility contains various financial covenants that impose a maximum leverage ratio of 4.0 to 1.0, a debt to capitalization ratio of 0.5 to 1.0, a minimum interest expense coverage ratio of 3.0 to 1.0 and a minimum collateral maintenance of 150% of the aggregate amount outstanding under the credit facility. Our ability to meet these covenants or requirements may be affected by events beyond our control, and there can be no assurance that we will satisfy such covenants and requirements in the future. Such restrictions may limit our ability to successfully execute our business plans, which may have adverse consequences on our operations.
We may not be able to generate sufficient cash to service all of our indebtedness, and may be forced to take other actions to satisfy our obligations under our indebtedness, which may not be successful.

Our ability to make scheduled payments on or to refinance our debt obligations depends on our financial position, results of operations and cash flows, which is subject to prevailing economic and competitive conditions and to certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or
delay investment decisions and capital expenditures, or to sell assets, seek additional capital or restructure or refinance our indebtedness. Our ability to restructure or refinance our debt will depend on the condition of the capital markets and our financial position at such time. Any refinancing of our debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of existing or future debt instruments may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of such operating results and resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. Our existing debt agreements restrict our ability to dispose of assets and use the proceeds from the disposition. We may not be able to consummate those dispositions or to obtain the proceeds that we could realize from them and these proceeds may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations. If we breach our covenants under our senior secured revolving credit facility and seek a waiver, we may not be able to obtain a waiver from the required lenders. If this occurs, we would be in default

under our senior secured revolving credit facility, the lenders could exercise their rights and we could be forced into bankruptcy or liquidation. See “Management's Discussion and Analysis of Financial Condition and Results of Operations-Liquidity and Capital Resources-Revolving Credit Facility.”

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Our property consists primarily of mobile offshore drilling rigs and ancillary equipment. Six of our rigs (the Atwood Aurora, the Atwood Beacon, the Atwood Eagle, the Atwood Falcon, the Atwood Hunter, and the Atwood Osprey) are pledged under our senior secured revolving credit facility. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Revolving Credit Facility” in Item 7 of this Form 10-K.

We lease our office at our corporate headquarters in the United States and own or lease support offices in Australia, Malaysia, Singapore and the United Kingdom.

We incorporate by reference in response to this item the information set forth in Item 1, Item 7 and Note 4 of the Notes to our Consolidated Financial Statements in this Form 10-K.

ITEM 3. LEGAL PROCEEDINGS

We have certain actions, claims and other matters pending as discussed and reported in Notes to Consolidated Financial Statements included in Item 8 of this Form 10-K. As of September 30, 2012, we were also involved in a number of lawsuits which have arisen in the ordinary course of business and for which we do not expect the liability, if any, resulting from these lawsuits to have a material adverse effect on our current consolidated financial position, results of operations or cash flows. We cannot predict with certainty the outcome or effect of any of these matters described above or any such other proceeding or threatened litigation or legal proceedings. There can be no assurance that our beliefs or expectations as to the outcome or effect of any lawsuit or other matters will prove correct and the eventual outcome of these matters could materially differ from management’s current estimates.

ITEM 4. MINE SAFETY DISCLOSURE

Not applicable.

PART II

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

As of November 8, 2012, there were approximately 73 record owners of our common stock. Our common stock is traded on the New York Stock Exchange under the symbol "ATW".

We did not pay cash dividends in fiscal years 2012 or 2011 and we do not anticipate paying cash dividends in the foreseeable future because of the capital-intensive nature of our business and restrictions in our debt agreements. To enable us to maintain our highly competitive profile in the industry, we expect to utilize cash reserves at the appropriate time to construct additional equipment or to upgrade existing equipment. Our senior secured revolving credit facility prohibits payments of cash dividends on our common stock without lender approval, and the indenture governing our senior notes restricts payments of cash dividends on our common stock without noteholder approval subject to certain exceptions.

STOCK PRICE INFORMATION

The following table sets forth the range of high and low sales prices per share of common stock as reported by the NYSE for the periods indicated.

	Fiscal 2012		Fiscal 2011	
Quarters Ended	Low	High	Low	High
December 31	$30.64	$45.64	$29.48	$38.03
March 31	39.48	48.91	34.85	46.92
June 30	34.93	45.85	37.96	46.86
September 30	37.11	49.75	32.86	48.84

COMMON STOCK PRICE PERFORMANCE GRAPH

Below is a comparison of five-year cumulative total returns among Atwood Oceanics, Inc. and the center for research in security prices ("CRSP") index for the NYSE/AMEX/NASDAQ stock markets, and our self determined peer group of drilling companies.

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN (1)

	Fiscal Year Ended September 30,					
CRSP Total Returns Index for:	2007	2008	2009	2010	2011	2012
Atwood Oceanics, Inc.	100.0	95.1	92.1	79.6	89.8	118.8
NYSE/AMEX/Nasdaq Stock Markets (U.S. Companies)	100.0	79.0	70.8	79.4	79.8	103.6
Self-determined Peer Group	100.0	93.1	77.9	68.9	60.2	75.8

Constituents of the Self-determined Peer Group (weighted according to market capitalization):

Diamond Offshore Drilling, Inc.	Transocean Ltd.	Rowan Companies, Inc.
Ensco plc	Noble Corporation	Seadrill Limited

(1) Total returns assume (i) that $100 was invested in each on September 30, 2007; (ii) dividends, if any, were reinvested; and (iii) a September 30 fiscal year end.

The performance graph above is furnished and not filed for purposes of Section 18 of the Securities Exchange Act of 1934 and will not be incorporated by reference into any registration statement filed under the Securities Act of 1933 unless specifically identified therein as being incorporated therein by reference. The performance graph is not soliciting material subject to Regulation 14A.

UNREGISTERED SALES OF EQUITY SECURITIES

None.

ISSUER PURCHASES OF EQUITY SECURITIES

None.

ITEM 6. SELECTED FINANCIAL DATA

Selected financial data for each of the last five fiscal years is presented below:

	At or For the Years Ended September 30,				
(In thousands, except per share amounts, fleet data and ratios)	2012	2011	2010	2009	2008
STATEMENTS OF OPERATIONS DATA:					
Operating revenues	$787,421	$645,076	$650,562	$586,507	$526,604
Contract drilling costs	(347,179)	(223,565)	(252,427)	(221,709)	(216,395)
Depreciation	(70,599)	(43,597)	(37,030)	(35,119)	(34,783)
General and administrative	(49,776)	(44,407)	(40,620)	(31,639)	(30,975)
Other, net	(457)	(4,847)	1,855	402	155
Operating income	319,410	328,660	322,340	298,442	244,606
Other (expense) income	(6,106)	(3,813)	(2,361)	(2,011)	169
Tax provision	(41,133)	(53,173)	(62,983)	(45,686)	(29,337)
Net Income	$272,171	$271,674	$256,996	$250,745	$215,438
PER SHARE DATA:					
Earnings per common share:					
Basic	$4.17	$4.20	$3.99	$3.91	$3.38
Diluted	$4.14	$4.15	$3.95	$3.89	$3.34
Average common shares outstanding:					
Basic	65,267	64,754	64,391	64,167	63,756
Diluted	65,781	65,403	65,028	64,493	64,556
FLEET DATA:					
Number of rigs owned, at end of period	11	10	9	9	8
Utilization rate for in-service rigs (1)	100%	95%	88%	85%	100%
BALANCE SHEET DATA:					
Cash and cash equivalents	$77,871	$295,002	$180,523	$100,259	$121,092
Working capital	233,867	301,608	266,534	191,686	248,052
Property and equipment, net	2,537,340	1,887,321	1,343,961	1,184,300	787,838
Total assets	2,943,762	2,375,391	1,724,440	1,509,402	1,096,597
Total debt	830,000	520,000	230,000	275,000	170,000
Shareholders' equity (2)	1,939,422	1,652,787	1,370,134	1,102,293	843,690
Ratio of current assets to current liabilities	2.71	2.89	3.85	2.70	5.36

(1) Excludes any contractual downtime for shipyard projects. Fiscal years 2011 and 2012 also exclude cold-stacked rigs which were not actively marketed.

(2) We have never paid any cash dividends on our common stock.

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

The following discussion is intended to assist in understanding our financial position at September 30, 2012 and 2011, and our results of operations for each of the fiscal years for the three year period ended September 30, 2012, and should be read in conjunction with the accompanying consolidated financial statements and related notes in Item 8 of this Form 10-K. The following discussion and analysis contains forward-looking statements that involve risks and uncertainties. Our actual results may differ materially from those anticipated in these forward-looking statements as a result of certain factors, including those set forth under Item 1A "Risk Factors" in this Form 10-K. See "Forward-Looking Statements".

MARKET OUTLOOK

Overview

Our fiscal year 2012 financial and operating results include:

- Record operating revenues totaling $787 million
- Record net income of $272 million
- Diluted earnings per share of $4.14
- Net cash from operating activities of $256 million
- Debt to capitalization ratio of 30% at September 30, 2012

Industry Conditions

The offshore drilling market continued to strengthen throughout fiscal year 2012 with all rig classes experiencing improved utilization levels in response to higher than average oil prices. The ultra-deepwater floater market has been the principal beneficiary of the strengthening market as evidenced by the relatively higher increase in day rates and near full utilization for this rig class during the year. Day rates for all other rig classes also experienced improvement, albeit at a slower pace.

The strength of the ultra-deepwater market is also evidenced by an increase of newbuild rig construction orders since the beginning of 2011. The pace of rig orders, however, has recently slowed from the prior year as contract drilling companies navigate between disrupting long term supply and demand dynamics by adding additional newbuild rigs and growing their rig fleet at reasonable construction prices in a strong day rate environment.

The global macro environment, including the sovereign debt issues in Europe and slower economic growth in the U.S., China and several developing countries, coupled with the uncertainty associated with U.S. fiscal policy and economic recovery, create a high level of market volatility and threaten to disrupt favorable offshore drilling market conditions. In addition, capacity constraints in the offshore rig equipment global supply chain and the shortage of skilled personnel are negatively impacting operating costs leading to margin compression in certain operating jurisdictions.

Drilling activity in the U.S. Gulf of Mexico is rebounding to pre-Macondo levels and the drilling permit approval process is now functioning capably. However, we cannot be certain that this level of activity will continue into the future or that additional restrictions or regulations will not be implemented which might negatively impact drilling activity or the drilling permit approval process in the U.S. Gulf of Mexico.

West Africa, East Africa and certain other deepwater and ultra-deepwater frontiers are experiencing exploration success which is driving increased contract tender requests and awards at increasingly higher day rates. Further improvements in ultra-deepwater and deepwater rig utilization and day rates will depend in large part on projected oil prices, the strength of the global economy, and any additional impacts from the Macondo incident and associated new regulatory, legislative and permitting requirements.

Ultra-deepwater and Deepwater Rigs

Industry-wide, deepwater rig utilization increased from 89% at the end of fiscal year 2011 to 98% currently, while ultra-deepwater utilization remains at full utilization. Only eight newbuild floaters are available through the end of

2013. For calendar year 2013, the vast majority of both ultra-deepwater and deepwater available days are contracted for the respective industry-wide fleets.

As of October 1, 2012, there were 69 drillships and 12 semisubmersibles under construction for delivery through January 2020. This includes 28 ultra-deepwater rigs to be constructed in shipyards located in Brazil, all of which are under long-term contracts with Petrobras. Of the remaining 53 ultra-deepwater rigs under construction, 25 are currently contracted, with several others under announced letters of intent.

The Atwood Condor began its 21-month contract with Hess Corporation in the fourth quarter of fiscal year 2012 in the U.S. Gulf of Mexico and is contracted through July 2014. The Atwood Osprey continued its six-year commitment offshore Australia with Chevron Australia and is contracted through the third quarter of fiscal year 2017.

The Atwood Eagle and Atwood Falcon are contracted through the third quarter of fiscal year 2014 and the first quarter of fiscal year 2015, respectively, while the Atwood Hunter is contracted throughout fiscal year 2013.

The Atwood Advantage and Atwood Achiever are DP-3 dynamically-positioned, dual derrick, ultra-deepwater drillships rated to operate in water depths up to 12,000 feet, and are currently under construction at the Daewoo Shipbuilding and Marine Engineering Co., Ltd. ("DSME") shipyard in South Korea. These drillships will have enhanced technical capabilities, including two seven-ram BOPs, three 100-ton knuckle boom cranes, a 165-ton active heave "tree-running" knuckle boom crane and 200 person accommodations. The Atwood Advantage and Atwood Achiever are expected to be delivered during the fourth quarter of fiscal year 2013 and third quarter of fiscal 2014, respectively, at a total cost, including project management, drilling, handling tools and spares, of approximately $635 million each. Upon delivery from the shipyard, the Atwood Advantage will mobilize to the Eastern Mediterranean Sea to commence a drilling program with Noble which extends through the first quarter of fiscal year 2017.

In September 2012, we entered into a turnkey construction contract with DSME to construct a third ultra-deepwater drillship, the Atwood Admiral, at the DSME yard in South Korea. The Atwood Admiral is expected to be delivered during the second quarter of fiscal year 2015. The design of the Atwood Admiral will be substantially identical to the previously ordered Atwood Advantage and Atwood Achiever.

In addition, we have until June 30, 2013 to exercise our option to build an additional ultra-deepwater drillship with DSME. At this time, we have made no determination as to whether that option will be exercised. In determining whether to exercise the option we will consider several factors, including oil and gas prices, the magnitude of our contract drilling revenue backlog, the current and prospective supply and demand dynamics of the ultra-deepwater drilling segment, current ultra-deepwater contract day rates and newbuild drillship construction prices.

Although we currently do not have drilling contracts for the Atwood Achiever or the Atwood Admiral, we expect that the long-term demand for ultra-deepwater drilling services in established and emerging basins should provide us with opportunities to contract these two rigs prior to their delivery dates.

Jackup Rigs

The bifurcation in day rates and utilization continues to drive contracting activity in the jackup market. Currently, higher specification jackup rigs are achieving marketed utilization levels of approximately 98% as compared to 91% for the remainder of the global jackup fleet. While higher specification rigs represent less than 30% of the global jackup fleet, we expect the bifurcation trend to continue. Despite the expected increase in supply due to the continued delivery of high specification newbuild rigs through the end of next year, we expect that operators will continue to prefer contracting newer, more capable high specification jackups.

As a result of newbuild construction programs initiated during 2005 and continuing through 2010, the jackup supply continues to increase. As of October 1, 2012, there were 88 newbuild jackup rigs under construction, of which 11 are scheduled for delivery during the remainder of 2012, 48 are scheduled for delivery during 2013 and the remainder are scheduled for delivery thereafter. Approximately only 20% of jackup rigs yet to be delivered are currently uncontracted, and approximately 20% are not considered high specification rigs (i.e., less than 350-foot water depth capability) and therefore do not compete with the majority of our jackup fleet. Additionally, approximately 27 rigs are capable of working year-round in the North Sea and offshore Norway, and therefore are not directly competing with our jackup fleet.

The Atwood Mako and Atwood Manta are contracted through fiscal year 2013 and the first quarter of fiscal year 2014, while the Atwood Aurora and Atwood Beacon are contracted for 11 and seven months in fiscal year 2013, respectively. The Vicksburg is contracted through the end of the first fiscal quarter of 2014. Due to market bifurcation for high-specification jackups, we expect the Atwood Aurora and Atwood Beacon to continue to operate with high utilization and increasing day rates while the Vicksburg may encounter greater competition resulting in lower utilization, with day rates remaining under pressure for the foreseeable future.

We currently have two Pacific Class 400 jackup drilling units, the Atwood Manta and the Atwood Orca, similar in design to the Atwood Mako, under construction at the PPL Shipyard Pte. Ltd. (“PPL”) shipyard in Singapore. These new rigs will have a rated water depth of 400 feet, accommodations for 150 personnel and significant offline handling features. The rigs are each expected to cost approximately $190 million, including project management, drilling, handling tools and spares, and are scheduled for delivery during the first and third quarters of fiscal year 2013. We currently do not have a drilling contract for the Atwood Orca, but we expect to contract this high-specification rig prior to its delivery date.

Idled Rigs

During fiscal year 2012, we sold the Richmond. The Atwood Southern Cross and Seahawk remain idle. We anticipate these two units will not return to service during fiscal year 2013 due to the lack of sufficient continuous demand, and thus, we are not actively marketing these rigs at this time.

Contract Backlog

We maintain a backlog of commitments for contract drilling revenues. Our contract backlog at September 30, 2012 was approximately $2.6 billion, representing a 73% increase compared to our contract backlog of $1.5 billion at September 30, 2011. We calculate our contract backlog by multiplying the day rate under our drilling contracts by the number of days remaining under the contract, assuming full utilization. The calculation does not include any revenues related to other fees such as for mobilization, demobilization, contract preparation, customer reimbursables and bonuses. The amount of actual revenues earned and the actual periods during which revenues are earned will be different from amounts disclosed in our backlog calculations due to various factors, including unscheduled repairs, maintenance, weather and other factors. Such factors may result in lower applicable day rates than the full contractual day rate. In addition, under certain circumstances, our customers may seek to terminate or renegotiate our contracts. See Item 1A., “Risk Factors—Our business may experience reduced profitability if our customers terminate or seek to renegotiate our drilling contracts” of this Form 10-K.

The following table sets forth as of September 30, 2012 the amount of our contract drilling revenue backlog and the percent of available operating days committed for our actively marketed drilling units for the periods indicated (dollars in millions):

	Fiscal 2013	Fiscal 2014	Fiscal 2015	Fiscal 2016	Fiscal 2017 and thereafter	Total
Contract drilling revenue backlog						
Ultra-deepwater and Deepwater	$778	$740	$403	$386	$156	$2,463
Jackups	162	11	—	—	—	173
	$940	$751	$403	$386	$156	$2,636
Percent of Available Operating Days Committed	82 %	37 %	16 %	8 %	5 %	

On October 3, 2012, we announced that one of our subsidiaries was awarded a drilling services contract by CEC International, Ltd. for work in the Gulf of Thailand and offshore Malaysia for the newbuild jackup Atwood Manta. As a result of this contract, our contract backlog increased by approximately $53 million and available operating days committed increased up to 91% in fiscal year 2013.

RESULTS OF OPERATIONS

Fiscal Year 2012 versus Fiscal Year 2011

Operating Revenues—Revenues for fiscal year 2012 increased $142.3 million, or 22%, compared to the prior fiscal year. A comparative analysis of revenues by rig for fiscal years 2012 and 2011 is as follows:

	Operating Revenues (In millions)		
	Fiscal Year 2012	Fiscal Year 2011	Variance
Atwood Condor	$36.1	$—	$36.1
Atwood Osprey	172.2	59.9	112.3
Atwood Eagle	135.6	139.8	(4.2)
Atwood Falcon	99.8	153.4	(53.6)
Atwood Hunter	195.0	183.4	11.6
Atwood Aurora	55.5	29.2	26.3
Atwood Beacon	51.5	45.1	6.4
Atwood Mako	4.3	—	4.3
Vicksburg	35.4	34.3	1.1
Other	2.0	—	2.0
	$787.4	$645.1	$142.3

Our newest ultra-deepwater, semisubmersible drilling rig, the Atwood Condor, which commenced operations under its initial contract during the fourth quarter of fiscal year 2012, earned mobilization revenue as it relocated from the shipyard in Singapore to the U.S. Gulf of Mexico.

The increase in revenues for the Atwood Osprey is due to the fact that the rig commenced drilling operations offshore Australia in late May 2011 and thus did not earn a full year of revenue in fiscal year 2011. The rig continued on contract offshore Australia for all of fiscal year 2012.

Revenues for the Atwood Eagle were relatively consistent compared to the prior fiscal year. The rig worked offshore Australia during both fiscal years 2012 and 2011.

The decrease in revenues for the Atwood Falcon is due to the rig working on a long-term contract offshore Malaysia for all of fiscal year 2011. This contract ended during the second quarter of fiscal year 2012. From February 2012 through May 2012, the rig underwent a shipyard project in Singapore for upgrades. Following completion of such upgrades, the rig relocated to work offshore Australia and began operations in late May 2012 that continued through the end of fiscal year 2012.

The increase in revenues for the Atwood Hunter is primarily due to out-of-service time related to a planned regulatory inspection during fiscal year 2011 compared to no out-of-service time during fiscal year 2012. The Atwood Hunter worked offshore West Africa during both fiscal years 2012 and 2011.

Revenues for the Atwood Aurora increased as the rig was fully utilized during fiscal year 2012 working offshore West Africa. In fiscal year 2011, the rig worked offshore Egypt until completion of its contract commitment in May 2011. The contract was followed by a planned shipyard project through June 2011, after which the rig was idle for most of the fourth quarter of fiscal year 2011 until it resumed work under a contract that commenced in September 2011.

Revenues for the Atwood Beacon were relatively consistent compared to the prior fiscal year. The rig continued to work offshore South America until the fourth quarter of fiscal year 2012 when it relocated to the Mediterranean Sea to prepare for drilling operations in Israel.

Our newest active jackup drilling unit, the Atwood Mako, was delivered from the shipyard and commenced drilling operations in September 2012 offshore Thailand, and thus earned no revenue in fiscal year 2011.

Revenues for the Vicksburg were relatively consistent compared to the prior fiscal year. The Vicksburg worked offshore Thailand during both fiscal years 2012 and 2011.

Contract Drilling Costs—Contract drilling costs for fiscal year 2012 increased $123.6 million, or 55%, compared to the prior fiscal year. A comparative analysis of contract drilling costs by rig for fiscal years 2012 and 2011 is as follows:

	Contract Drilling Costs (In millions)		
	Fiscal Year 2012	Fiscal Year 2011	Variance
Atwood Condor	$18.9	$—	$18.9
Atwood Osprey	66.0	22.9	43.1
Atwood Eagle	61.7	62.5	(0.8)
Atwood Falcon	56.6	29.4	27.2
Atwood Hunter	50.4	39.0	11.4
Atwood Aurora	31.0	18.5	12.5
Atwood Beacon	34.6	28.7	5.9
Atwood Mako	3.0	—	3.0
Vicksburg	20.8	16.4	4.4
Other	4.2	6.2	(2.0)
	$347.2	$223.6	$123.6

The Atwood Condor incurred costs as it relocated from the shipyard in Singapore to the U.S. Gulf of Mexico during the fourth quarter of fiscal year 2012 while on contract. No drilling costs were incurred in fiscal year 2011 while the rig was under construction.

The Atwood Osprey commenced drilling operations in May 2011, incurring approximately four months of drilling costs in fiscal year 2011 as compared to a full twelve months of drilling costs in fiscal year 2012 while working offshore Australia.

Contract drilling costs for the Atwood Eagle were relatively consistent as compared to the prior fiscal year. The rig continued to work offshore Australia during both fiscal years 2012 and 2011.

The increase in contract drilling costs for the Atwood Falcon, as compared to the prior fiscal year, is primarily due to increased maintenance activities during the shipyard project from February 2012 to May 2012 and the subsequent commencement of drilling operations offshore Australia which has significantly higher personnel costs than costs for its previous contract offshore Malaysia.

The increase in contract drilling costs for the Atwood Hunter is due primarily to increased equipment-related costs associated with maintenance projects and inspections as compared to the prior fiscal year.

The increase in contract drilling costs for the Atwood Aurora, as compared to the prior fiscal year, is primarily attributable to increased costs for monthly amortization charges for mobilization to offshore West Africa in the current fiscal year as well as lower operating expenses incurred at the end of fiscal year 2011 due to a planned shipyard project and substantial idle time prior to commencing its next contract offshore West Africa.

The increase in contract drilling costs for the Atwood Beacon is primarily due to increased equipment-related costs associated with maintenance projects and inspections incurred while the rig relocated from South America to the Mediterranean Sea during the fourth quarter of fiscal year 2012.

The Atwood Mako was delivered from the shipyard and commenced drilling operations in Thailand in September 2012. No drilling costs were incurred in fiscal year 2011 while the rig was under construction.

The increase in contract drilling costs for the Vicksburg is attributable to increased equipment-related costs associated with maintenance projects when compared to the prior fiscal year.

Other contract drilling costs were relatively consistent with the prior fiscal year.

Depreciation—Depreciation expense for the fiscal year 2012 increased $27.0 million, or 62%, compared to the prior fiscal year. A comparative analysis of depreciation expense by rig for fiscal years 2012 and 2011 is as follows:

	Depreciation Expense (In millions)		
	Fiscal Year 2012	Fiscal Year 2011	Variance
Atwood Condor	$7.9	$—	$7.9
Atwood Osprey	24.8	8.3	16.5
Atwood Eagle	5.5	4.9	0.6
Atwood Falcon	6.4	5.1	1.3
Atwood Hunter	6.5	6.4	0.1
Atwood Aurora	7.4	7.4	—
Atwood Beacon	4.9	4.6	0.3
Atwood Mako	0.6	—	0.6
Vicksburg	1.9	2.0	(0.1)
Other	4.7	4.9	(0.2)
	$70.6	$43.6	$27.0

The Atwood Condor, which was placed into service at the beginning of July 2012, incurred no depreciation expense in fiscal year 2011.

The Atwood Osprey, which was placed into service in late May 2011, incurred only four months of depreciation expense in fiscal year 2011.

The increase in depreciation for the Atwood Falcon is due to certain upgrades made to the rig during the shipyard project which was completed in May 2012.

The Atwood Mako, which was placed into service at the beginning of September 2012, incurred no depreciation expense in fiscal year 2011.

Depreciation expense for all other rigs remained relatively consistent during fiscal year 2012 as compared to the prior fiscal year.

General and administrative—General and administrative expenses for fiscal year 2012 increased approximately $5.4 million, or 12%, compared to the prior fiscal year primarily due to higher personnel-related costs resulting from an increase in headcount to support our larger fleet.

Other, net—The decrease in Other expenses is primarily due to a $5.0 million charge related to an impairment of certain of our idled equipment during fiscal year 2011.

Income taxes—Our effective tax rate was 13% for fiscal year 2012, as compared to the prior fiscal year effective tax rate of 16%. The lower effective income tax was primarily due to the favorable resolution of prior period tax examinations.

Fiscal Year 2011 versus Fiscal Year 2010

Operating Revenues—Revenues for fiscal year 2011 decreased $5.5 million, or 1%, compared to fiscal year 2010. A comparative analysis of revenues by rig for fiscal years 2011 and 2010 is as follows:

	Operating Revenues (In millions)		
	Fiscal Year 2011	Fiscal Year 2010	Variance
Atwood Osprey	$59.9	$—	$59.9
Atwood Eagle	139.8	134.1	5.7
Atwood Falcon	153.4	154.0	(0.6)
Atwood Hunter	183.4	197.4	(14.0)
Atwood Aurora	29.2	46.6	(17.4)
Atwood Beacon	45.1	34.1	11.0
Vicksburg	34.3	34.2	0.1
Other	—	50.2	(50.2)
	$645.1	$650.6	$(5.5)

The Atwood Osprey commenced drilling operations in late May 2011 offshore Australia, and thus, earned no revenue in fiscal year 2010.

Revenues for the Atwood Eagle and Atwood Falcon were relatively consistent compared to fiscal year 2010. The Atwood Eagle continued to work offshore Australia during both fiscal years 2011 and 2010 and the Atwood Falcon continued work on a long- term contract offshore Malaysia during both fiscal years 2011 and 2010.

The decrease in revenues for the Atwood Hunter is due to an increase in downtime related to unplanned repairs and maintenance and a planned regulatory inspection during fiscal year 2011. The Atwood Hunter worked offshore West Africa in fiscal years 2011 and 2010.

The increase in revenues for the Atwood Beacon is due to working on a higher day rate contract offshore South America compared to the fiscal year 2010 when the rig was working at a lower day rate offshore West Africa.

Revenues for the Atwood Aurora decreased during fiscal year 2011 due to the completion of its contract commitment in May 2011, which was followed by a planned shipyard project through June 2011. Following the shipyard project, the rig was idled for most of the fourth quarter of fiscal year 2011. The rig experienced virtually no downtime during the fiscal year 2010. In fiscal year 2011, until the time of the shipyard project, the rig worked offshore Egypt on the same long term contract that it worked under during fiscal year 2010. The Atwood Aurora resumed drilling operations offshore West Africa under a new contract that commenced late September 2011.

Revenues for the Vicksburg were relatively consistent compared to the fiscal year 2010. The Vicksburg worked offshore Thailand during both fiscal years 2011 and 2010.

Decreases in Other operating revenues during fiscal year 2011 are due to the Atwood Southern Cross, Richmond, and Seahawk all completing their respective drilling contracts and subsequently being idled. The idled state of these rigs resulted in the decrease of revenues for fiscal year 2011 compared to fiscal year 2010.

Contract Drilling Costs—Contract drilling costs for fiscal year 2011 decreased $28.8 million, or 11%, compared to fiscal year 2010. A comparative analysis of contract drilling costs by rig for fiscal years 2011 and 2010 is as follows:

	Contract Drilling Costs (In millions)		
	Fiscal Year 2011	Fiscal Year 2010	Variance
Atwood Osprey	$22.9	$—	$22.9
Atwood Eagle	62.5	53.0	9.5
Atwood Falcon	29.4	31.5	(2.1)
Atwood Hunter	39.0	37.0	2.0
Atwood Aurora	18.5	21.7	(3.2)
Atwood Beacon	28.7	27.8	0.9
Vicksburg	16.4	16.5	(0.1)
Other	6.2	64.9	(58.7)
	$223.6	$252.4	$(28.8)

The Atwood Osprey, commenced drilling operations in late May 2011, incurring approximately four months of drilling costs in fiscal year 2011 compared to none in fiscal year 2010.

The increase in contract drilling costs for the Atwood Eagle for fiscal year 2011 compared to fiscal year 2010 is attributable to higher local payroll and payroll related costs due to the strengthening of the Australian dollar along with increased equipment-related costs due to contract specific enhancements and additional maintenance projects performed during the extended regulatory inspection period during fiscal year 2011.

Contract drilling costs for the Atwood Falcon, Atwood Hunter, and the Atwood Beacon were relatively consistent when compared to fiscal year 2010.

The decrease in contract drilling costs for the Atwood Aurora for fiscal year 2011 compared to fiscal year 2010 is due to lower operating expenses being incurred during a planned shipyard project in May and June 2011 and the idle time incurred during the remainder of fiscal year 2011.

Contract drilling costs for the Vicksburg were relatively consistent when compared to fiscal year 2010.

Decreases in Other contract drilling costs during fiscal year 2011 are due to reduced operating costs for the Richmond, Atwood Southern Cross and Seahawk as a result of these rigs being idled and not being actively marketed. The decreases are also due to a combination of higher percentage of Other contract drilling costs allocated to rig contract drilling costs in fiscal year 2011 when compared to fiscal year 2010 and recognition of foreign exchange gains in fiscal year 2011 compared to foreign exchange losses in fiscal year 2010.

Depreciation—Depreciation expense for fiscal year 2011 increased $6.6 million, or 18%, as compared to fiscal year 2010. A comparative analysis of depreciation expense by rig for fiscal years 2011 and 2010 is as follows:

	Depreciation Expense (In millions)		
	Fiscal Year 2011	Fiscal Year 2010	Variance
Atwood Osprey	$8.3	$—	$8.3
Atwood Eagle	4.9	4.8	0.1
Atwood Falcon	5.1	5.4	(0.3)
Atwood Hunter	6.4	6.3	0.1
Atwood Aurora	7.4	7.3	0.1
Atwood Beacon	4.6	4.6	—
Vicksburg	2.0	2.0	—
Other	4.9	6.6	(1.7)
	$43.6	$37.0	$6.6

The Atwood Osprey, which was placed into service in late May 2011, incurred no depreciation expense in fiscal year 2010.

Depreciation expense for all other rigs remained relatively consistent during fiscal year 2011 as compared to fiscal year 2010.

General and administrative—General and administrative expenses for fiscal year 2011 increased approximately $3.8 million, or 9%, compared to the fiscal year 2010 primarily due to rising personnel costs resulting, in part, from various expenses related to the transition of executive leadership, wage increases and increased annual bonus and share-based compensation costs during fiscal year 2011.

Other, net —The increase in Other expenses is primarily due to a $5.0 million charge related to an impairment of certain of our idled equipment during fiscal year 2011. The Other category amounts for fiscal year 2010 were attributable to the sale of equipment during the year.

Income taxes—Our effective tax rate was 16% for fiscal year 2011, as compared to fiscal year 2010 effective tax rate of 20%. The lower effective income tax was primarily due to lower taxes on foreign earned income.

LIQUIDITY AND CAPITAL RESOURCES

Capital expenditures totaled $785 million for fiscal year 2012. Capital expenditures and working capital needs were funded by cash flows from operations of approximately $256 million, a net increase in our long-term debt of $310 million, and cash on hand from the prior fiscal year end. Although our net income for fiscal year 2012 was relatively consistent with the prior fiscal year, our cash flows from operations of $256 million decreased $84 million as compared to approximately $340 million for the prior fiscal year. The increase of accounts receivable is attributable to higher revenue levels and a higher number of active in-service rigs at the current fiscal year end when compared to the prior fiscal year end.

Although our cash and cash equivalents decreased to $78 million as of September 30, 2012 from $295 million as of September 30, 2011, our working capital only decreased to $234 million from $302 million for the same fiscal year end periods. The decrease in cash and cash equivalents is partially offset by the increase in accounts receivable as mentioned above, an increase in inventory due to more active in-service rigs and a decrease in accounts payable due to a reduction of accrued but unpaid invoices related to our construction projects when compared to prior fiscal year end.

To date, general inflationary trends have not had a material effect on our operating revenues or expenses.

Revolving Credit Facility

As of September 30, 2012, we had $380 million of outstanding borrowings under our five-year $750 million senior secured revolving credit facility. Including the $450 million aggregate principal amount of our senior notes, we had a total debt to capitalization ratio of 30%. Our wholly-owned subsidiary, Atwood Offshore Worldwide Limited (“AOWL”), is the borrower under the credit facility, and we and certain of our other subsidiaries are guarantors under the facility. Borrowings under the credit facility bear interest at the Eurodollar rate plus a margin of 2.50%. Certain borrowings effectively bear interest at a fixed rate due to our interest rate swaps. The average interest rate for borrowings under the credit facility was approximately 3.2% per annum at September 30, 2012, after considering the impact of our interest rate swaps. The credit facility also provides for the issuance, when required, of standby letters of credit. The credit facility has a commitment fee of 1.0% per annum on the unused portion of the underlying commitment. As of September 30, 2012, we had standby letters of credit issued in the aggregate amount of $0.1 million. As of November 1, 2012, an additional $155 million had been borrowed under our facility subsequent to September 30, 2012, leaving $215 million of available borrowing capacity under the facility. Subject to the satisfaction of certain conditions precedent and the agreement by the lenders, the credit facility includes an "accordion" feature which, if exercised, will increase total commitments by up to $550 million, bringing the total commitment to $1.3 billion.

The credit facility contains various financial covenants that impose a maximum leverage ratio of 4.0 to 1.0, a debt to capitalization ratio of 0.5 to 1.0, a minimum interest expense coverage ratio of 3.0 to 1.0 and a minimum collateral maintenance of 150% of the aggregate amount outstanding under the credit facility. In addition, the credit facility contains limitations on our and certain of our subsidiaries' ability to incur liens; merge, consolidate or sell substantially all assets; pay dividends (including restrictions on AOWL's ability to pay dividends to us); incur additional indebtedness; make advances, investments or loans; and transact with affiliates. The credit facility also contains customary events of default, including but not limited to delinquent payments, bankruptcy filings, material adverse judgments, guarantees or security documents not being in full effect, non-compliance with the Employee Retirement Income Security Act of 1974, cross-defaults under other debt agreements, or a change of control. The credit facility is secured primarily by first preferred mortgages on six of our active drilling units (the Atwood Aurora, the Atwood Beacon, the Atwood Eagle, the Atwood Falcon, the Atwood Hunter, and the Atwood Osprey), as well as liens on the equity interests of our subsidiaries that own, directly or indirectly, such drilling units. In addition, if we exercise the accordion feature and increase the total commitments, the credit facility requires that we provide a first preferred mortgage on the Atwood Condor, the Atwood Mako and the Atwood Manta, as well as a lien on the equity interests of our subsidiaries that own, directly or indirectly, such rigs. We were in compliance with all financial covenants under the credit facility at September 30, 2012.

Senior Notes

In January 2012, we issued $450 million aggregate principal amount of 6.50% Senior Notes due 2020 (the “Notes”). We received net proceeds, after deducting underwriting discounts and offering expenses, of approximately $440 million. We used the net proceeds to reduce outstanding borrowings under our credit facility.

The Notes are our senior unsecured obligations and are not currently guaranteed by any of our subsidiaries. Interest is payable on the Notes semi-annually in arrears. The indenture governing the Notes contains provisions that limit our ability and the ability of our restricted subsidiaries to incur or guarantee additional indebtedness or issue preferred stock; pay dividends or make other restricted payments; sell assets; make investments; create liens; enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us; and consolidate, merge or transfer all or substantially all of our assets. Many of these restrictions will terminate if the Notes become rated investment grade. The indenture governing the Notes also contains customary events of default, including payment defaults; defaults for failure to comply with other covenants in the indenture; cross-acceleration and entry of final judgments in excess of $50.0 million; and certain events of bankruptcy, in certain cases subject to notice and grace periods. We are required to offer to repurchase the Notes in connection with specified change in control events or with excess proceeds of asset sales not applied for permitted purposes.

At any time prior to February 1, 2015, we may, on any one or more occasions, redeem up to 35% of the aggregate principal amount of the Notes with the net cash proceeds of certain equity offerings at a redemption price set forth in the indenture governing the Notes. At any time prior to February 1, 2016, we may, on any one or more occasions, redeem the Notes in whole or in part at a redemption price equal to 100% of the principal amount of the Notes redeemed plus a "make whole" premium. On and after February 1, 2016, we may, on any one or more occasions, redeem the Notes in whole or in part at the redemption price set forth in the indenture governing the Notes.

Capital Expenditures

Our capital expenditures, including maintenance capital expenditures, for fiscal year 2012 totaled $785 million. We estimate that our total capital expenditures for fiscal year 2013 will be approximately $615 million, substantially all of which is contractually committed. These capital expenditures are expected to be funded with existing cash balances on hand, cash flows from operations and additional borrowings under our revolving credit facility.

As of September 30, 2012, we had expended approximately $438 million on our five drilling units under construction at such time. The expected remaining costs for our five drilling units under construction are as follows (in millions):

Fiscal 2013	Fiscal 2014	Fiscal 2015	Fiscal 2016	Total
$538	$812	$411	$—	$1,761

We believe that we will be able to fund all additional construction costs with cash flow from operations and borrowings under our revolving credit facility, which has provisions to increase the total commitment to $1.3 billion as described above.

Other

From time to time, we may seek possible expansion and acquisition opportunities relating to our business, which may include the construction or acquisition of rigs or other businesses in addition to those described in this Form 10-K. Such determinations will depend on market conditions and opportunities existing at that time, including with respect to the market for drilling contracts and day rates and the relative costs associated with such expansions or acquisitions. The timing, success or terms of any such efforts and the associated capital commitments are not currently known. In addition to cash on hand, cash flow from operations and borrowings under our revolving credit facility, we may seek to access the capital markets to fund such opportunities. Our ability to access the capital markets depends on a number of factors, including, among others, our credit rating, industry conditions, general economic conditions, market conditions and market perceptions of us and our industry. In addition, we continually review the possibility of disposing of assets that we do not consider core to our long-term business plan.

In addition, in the future, we may seek to redeploy our assets to more active regions if we have the opportunity to do so on attractive terms. We frequently bid for or negotiate with customers regarding multi-year contracts that could require significant capital expenditures and mobilization costs. We expect to fund these opportunities primarily with cash on hand, cash flow from operations and borrowings under our revolving credit facility.

OFF-BALANCE SHEET ARRANGEMENTS

We have no off-balance sheet arrangements as that term is defined in Item 303(a)(4)(ii) of Regulation S-K.

COMMITMENTS AND CONTRACTUAL OBLIGATIONS

The following table summarizes our obligations and commitments (in thousands) as of September 30, 2012:

	Fiscal 2013	Fiscal 2014	Fiscal 2015	Fiscal 2016	Fiscal 2017 and thereafter	Total
Debt and Interest (1)	$36,823	$31,254	$29,656	$409,656	$548,963	$1,056,352
Purchase Commitments (2)	454,000	731,000	369,000	—	—	1,554,000
Operating Leases (3)	2,603	3,588	2,329	1,825	12,980	23,325
	$493,426	$765,842	$400,985	$411,481	$561,943	$2,633,677

(1) Amounts include principal payments on the Notes and credit facility, fixed interest payments on the Notes and swaps(assuming September 30, 2012 LIBOR for floating rate), and short-term notes payable.

(2) Includes commitments related to our five drilling units under construction as of September 30, 2012.

(3) We enter into operating leases in the normal course of business. Some lease agreements provide us with the option to renew the leases. Our future operating lease payments would change if we exercised these renewal options and if we entered into additional operating lease agreements.

CRITICAL ACCOUNTING POLICIES

Significant accounting policies are included in Note 2 to our Consolidated Financial Statements for the year ended September 30, 2012. These policies, along with the underlying assumptions and judgments made by management in their application, have a significant impact on our consolidated financial statements. We identify our most critical accounting policies as those that are the most pervasive and important to the portrayal of our financial position and results of operations, and that require the most difficult, subjective and/or complex judgments by management regarding estimates about matters that are inherently uncertain. Our most critical accounting policies are those related to revenue recognition, property and equipment, impairment of assets, income taxes, and employee stock-based compensation.

Revenue Recognition

We account for contract drilling revenue in accordance with the terms of the underlying drilling contract. These contracts generally provide that revenue is earned and recognized on a daily rate (i.e. “day rate”) basis, and day rates are typically earned for a particular level of service over the life of a contract. Day rate contracts can be performed for a specified period of time or the time required to drill a specified well or number of wells. Revenues from day rate drilling operations, which are classified under contract drilling services, are recognized on a per day basis as services are performed assuming collectability is reasonably assured.

Deferred fees and costs

Fees received as compensation for the relocating drilling rigs from one major operating area to another, equipment and upgrade costs reimbursed by the customer, as well as receipt of advance billings of day rates are recognized as earned during the expected term of the related drilling contract, as are the day rates associated with such contracts. However, fees received upon termination of a drilling contract are generally recognized as earned during the period termination occurs as the termination fee is usually conditional based on the occurrence of an event as defined in the drilling contract, such as not obtaining follow on work to the contract in progress or relocation beyond a certain distance when the contract is completed. If receipt of such fees are not conditional, they will be recognized as earned on a straight-line method over the expected term of the related drilling contract.

We defer the mobilization costs relating to moving a drilling rig to a new area, which are incurred prior to the commencement of the drilling operations and customer requested equipment purchases that will revert to the customer at the end of the applicable drilling contract. We amortize such costs on a straight-line basis over the expected term of the applicable drilling contract. Contract revenues and drilling costs are reported in the Consolidated Statements of Operations at their gross amounts.

Property and Equipment

Property and equipment is stated at cost, reduced by provisions to recognize economic impairment in value whenever events or changes in circumstances indicate an asset’s carrying value may not be recoverable. At September 30, 2012, the carrying value of our property and equipment totaled approximately $2.5 billion, which represents approximately 86% of our total assets. The carrying value reflects the application of our property and equipment accounting policies, which incorporate estimates, assumptions and judgments by management relative to the useful lives and salvage values of our units. Once rigs and related equipment are placed in service, they are depreciated on the straight-line method over their estimated useful lives, with depreciation discontinued only during the period when a drilling unit is out-of-service while undergoing a significant upgrade that extends its useful life. The estimated useful lives of our drilling units and related equipment can range from 3 years to 35 years and our salvage values are generally estimated at 5% of capitalized costs. Any future increases or decreases in our estimates of useful lives or salvage values will have the effect of decreasing or increasing future depreciation expense, respectively.

We periodically evaluate our property and equipment to determine whether their net carrying value is in excess of their net realizable value. In determining an asset's fair value, these evaluations are performed considering a number of factors such as estimated future cash flows, appraisals and current market value analysis. Assets are written down to their fair value if the carrying amount of the asset is not recoverable and exceeds its fair value. Asset impairment evaluations are, by nature, highly subjective. Operations of our drilling equipment are subject to the offshore drilling requirements of oil and gas exploration and production companies and agencies of foreign governments. These requirements are, in turn, subject to fluctuations in government policies, world demand and price for petroleum products, proved reserves in relation to such demand and the extent to which such demand can be met from onshore sources. The critical estimates which result from these dynamics include projected utilization, day rates, and operating expenses, each of which impacts our estimated future cash flows. Over the last ten years, our equipment utilization rate has averaged approximately 95%; however, if a drilling unit incurs significant idle time or receives day rates below operating costs, its carrying value could become impaired.

The estimates, assumptions and judgments used by management in the application of our property and equipment and asset impairment policies reflect both historical experience and expectations regarding future industry conditions and operations. The use of different estimates, assumptions and judgments, especially those involving the useful lives of our rigs and vessels and expectations regarding future industry conditions and operations, would likely result in materially different carrying values of assets and results of operations.

Income Taxes

We conduct operations and earn income in numerous foreign countries and are subject to the laws of taxing jurisdictions within those countries, as well as United States federal and state tax laws. At September 30, 2012, we have an approximate $8.8 million net deferred income tax liability. This balance reflects the application of our income tax accounting policies. Such accounting policies incorporate estimates, assumptions and judgments by management relative to the interpretation of applicable tax laws, the application of accounting standards, and future levels of taxable income. The estimates, assumptions and judgments used by management in connection with accounting for income taxes reflect both historical experience and expectations regarding future industry conditions and operations. Changes in these estimates, assumptions and judgments could result in materially different provisions for deferred and current income taxes.

A comprehensive model is used to account for uncertain tax positions, which includes consideration of how we recognize, measure, present and disclose uncertain tax positions taken or to be taken on a tax return. The income tax laws and regulations are voluminous and are often ambiguous. As such, we are required to make many subjective assumptions and judgments regarding our tax positions that can materially affect amounts recognized in our consolidated balance sheets and statements of income.

Share-based Compensation

Share-based compensation cost is measured at the grant date, based on the calculated fair value of the award, and is recognized as an expense over the requisite service period (generally the vesting period of the equity grant).

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In December 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2011-12, "Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in ASU Update 2011-05" (Topic 220) to effectively defer only those changes in ASU Update 2011-05 that relate to the presentation of reclassification adjustments out of accumulated other comprehensive income. The amendments in this update supersede changes to those paragraphs in ASU 2011-05 that pertain to how, when, and where reclassification adjustments are presented. The amendments will be temporary to allow the FASB time to deliberate the presentation requirements for reclassifications out of accumulated other comprehensive income for annual and interim financial statements. The amendments in this update are effective at the same time as the amendments in ASU 2011-05 so that entities will not be required to comply with the presentation requirements in ASU 2011-05 that this update is deferring. We adopted the amendments in ASU 2011-05 on June 30, 2011 with no material impact on our consolidated financial statements or disclosures in our financial statements.

In December 2011, the FASB issued ASU 2011-11, "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities" for an entity to provide enhanced disclosures that will enable users of its financial statements to evaluate the effect or potential effect of netting arrangements on an entity's financial position. An entity is required to apply the amendments for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. An entity should provide the disclosures required by those amendments retrospectively for all comparative periods presented. We will adopt the accounting standards effective January 1, 2013. We do not expect that our adoption will have a material effect on our financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk, including adverse changes in interest rates and foreign currency exchange rates as discussed below.

Interest Rate Risk

The provisions of our credit facility provide for a variable interest rate cost on our $380 million outstanding as of September 30, 2012. However, we employ an interest rate risk management strategy that utilizes derivative instruments with respect to $250 million of our debt as of September 30, 2012 in order to minimize or eliminate unanticipated fluctuations in earnings and cash flows arising from changes in, and volatility of, interest rates. Effectively, only $130 million of our variable long-term debt outstanding as of September 30, 2012 is subject to changes in interest rates. Thus, a 10% change in the interest rate on the floating rate debt would have an immaterial impact on our annual earnings and cash flows.

Foreign Currency Risk

As a multinational company, we conduct business in numerous foreign countries. Our functional currency is the U.S. dollar. Certain of our subsidiaries have monetary assets and liabilities that are denominated in a currency other than our functional currency. Based on September 30, 2012 amounts, a decrease in the value of 10% in foreign currencies relative to the U.S. dollar would not have a material effect to our annual earnings and cash flows. We did not have any open derivative contracts relating to foreign currencies at September 30, 2012.

Market Risk

Our Notes bear interest at a fixed interest rate whose fair value will fluctuate based on changes in prevailing market interest rates and market perceptions of our credit risk. The fair value of our Notes was approximately $478.0 million at September 30, 2012, compared to the carrying amount of $450.0 million. If prevailing market interest rates had been 10% lower at September 30, 2012, the change in fair value of our Notes, would have been immaterial.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Atwood Oceanics, Inc. (which together with its subsidiaries is identified as the "Company," "we" or "our," unless stated otherwise or the context requires otherwise) is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Our internal control over financial reporting was designed by management, under the supervision of the Chief Executive Officer and Chief Financial Officer, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America, and includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

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

Management assessed the effectiveness of the Company's internal control over financial reporting as of September 30, 2012. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework.

Based on our evaluation under the criteria in Internal Control-Integrated Framework, management has concluded that the Company maintained effective internal control over financial reporting as of September 30, 2012.

PricewaterhouseCoopers LLP, our independent registered public accounting firm, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of September 30, 2012, which appears on the following page.

ATWOOD OCEANICS, INC.

by

/s/ Robert J. Saltiel	/s/ Mark L. Mey
Robert J. Saltiel	Mark L. Mey
President and	Senior Vice President and
Chief Executive Officer	Chief Financial Officer
November 19, 2012	November 19, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Atwood Oceanics, Inc.

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, comprehensive income, cash flows and changes in shareholders' equity present fairly, in all material respects, the financial position of Atwood Oceanics, Inc. and its subsidiaries at September 30, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2012 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of September 30, 2012, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

Houston, Texas

November 19, 2012

Atwood Oceanics, Inc. and Subsidiaries
CONSOLIDATED BALANCE SHEETS

(In thousands)	September 30, 2012	2011
ASSETS		
Current assets:		
Cash and cash equivalents	$77,871	$295,002
Accounts receivable	167,186	87,173
Income tax receivable	5,750	5,631
Inventories of materials and supplies	80,290	58,263
Prepaid expenses and deferred costs	39,437	14,862
Total current assets	370,534	460,931
Property and equipment, net	2,537,340	1,887,321
Other receivables	11,875	11,875
Deferred costs and other assets	24,013	15,264
Total assets	$2,943,762	$2,375,391
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$83,592	$113,021
Accrued liabilities	24,478	30,680
Notes payable	5,148	5,461
Income tax payable	9,711	8,461
Deferred credits	13,738	1,700
Total Current Liabilities	136,667	159,323
Long-term debt	830,000	520,000
Deferred income taxes	8,791	9,780
Deferred credits	8,928	7,910
Other long-term liabilities	19,954	25,591
Total long-term liabilities	867,673	563,281
Commitments and contingencies (Note 12)		
Shareholders' equity (Note 8):		
Preferred stock, no par value, 1,000 shares authorized, none outstanding	—	—
Common stock, $1.00 par value, 90,000 shares authorized with 65,452 and 64,960 issued and outstanding at September 30, 2012 and 2011, respectively	65,452	64,960
Paid-in capital	160,540	145,084
Retained earnings	1,716,441	1,444,270
Accumulated other comprehensive loss	(3,011)	(1,527)
Total shareholders' equity	1,939,422	1,652,787
Total liabilities and shareholders' equity	$2,943,762	$2,375,391

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

Atwood Oceanics, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended September 30,		
(In thousands, except per share amounts)	2012	2011	2010
Operating revenues			
Contract drilling	$787,421	$645,076	$650,562
Operating costs and expenses			
Contract drilling	347,179	223,565	252,427
Depreciation	70,599	43,597	37,030
General and administrative	49,776	44,407	40,620
Other, net	457	4,847	(1,855)
	468,011	316,416	328,222
Operating income	319,410	328,660	322,340
Other income (expense):			
Interest expense, net of capitalized interest	(6,460)	(4,530)	(2,725)
Interest income	354	717	364
	(6,106)	(3,813)	(2,361)
Income before income taxes	313,304	324,847	319,979
Provision for income taxes	41,133	53,173	62,983
Net income	$272,171	$271,674	$256,996
Earnings per common share (Note 2):			
Basic	$4.17	$4.20	$3.99
Diluted	$4.14	$4.15	3.95
Average common shares outstanding (Note 2):			
Basic	65,267	64,754	64,391
Diluted	65,781	65,403	65,028

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

Atwood Oceanics, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended September 30,		
(In thousands)	2012	2011	2010
Net income	$272,171	$271,674	$256,996
Other comprehensive loss, net of tax			
Loss on interest rate swaps	(1,484)	(1,527)	—
Other comprehensive loss	(1,484)	(1,527)	—
Total comprehensive income	$270,687	$270,147	$256,996

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

Atwood Oceanics, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended September 30,		
(In thousands)	2012	2011	2010
Cash flows from operating activities:			
Net income	$272,171	$271,674	$256,996
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	70,599	43,597	37,030
Amortization of debt issuance costs	3,625	2,363	803
Amortization of deferred items	(4,337)	3,333	13,755
Provision for doubtful accounts	—	—	(65)
Provision for inventory obsolescence	765	735	1,123
Deferred income tax (benefit) expense	(989)	(1,065)	4,798
Share-based compensation expense	10,402	6,314	9,998
Other, net	457	4,847	(1,855)
Change in assets and liabilities:			
(Increase) decrease in accounts receivable	(80,013)	13,214	26,187
Decrease in insurance receivable	—	—	281
(Increase) decrease in income tax receivable	(119)	10,421	(7,746)
Increase in inventory	(23,395)	(6,249)	(3,736)
(Increase) decrease in prepaid expenses	(6,386)	845	(179)
Increase in deferred costs and other assets	(32,597)	(10,379)	(10,321)
Increase (decrease) in accounts payable	27,536	(1,173)	4,735
Increase (decrease) in accrued liabilities	(7,096)	4,440	(854)
Increase (decrease) in income tax payable	1,250	(17,906)	(2,700)
Increase (decrease) in deferred credits and other liabilities	23,730	14,777	(21,850)
	(16,568)	68,114	49,404
Net Cash Provided by Operating Activities	255,603	339,788	306,400
Cash flows from investing activities:			
Capital expenditures	(785,083)	(514,858)	(187,094)
Collection of insurance receivable	—	—	3,607
Proceeds from sale of assets	7,646	218	1,504
Net Cash Used by Investing Activities	(777,437)	(514,640)	(181,983)
Cash flows from financing activities:			
Proceeds from issuance of bonds	450,000	—	—
Principal payments on bank credit facilities	(450,000)	(55,000)	(45,000)
Proceeds from bank credit facilities	310,000	345,000	—
Principal payments on notes payable	(5,461)	(3,631)	—
Proceeds from notes payable	5,148	9,092	—
Debt issuance costs paid	(10,530)	(12,322)	—
Proceeds from exercise of stock options	5,546	6,192	847
Net Cash Provided (Used) by Financing Activities	304,703	289,331	(44,153)
Net increase (decrease) in cash and cash equivalents	$(217,131)	$114,479	$80,264
Cash and cash equivalents, at beginning of period	$295,002	$180,523	$100,259
Cash and cash equivalents, at end of period	$77,871	$295,002	$180,523

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

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Atwood Oceanics, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

	Common Stock		Paid-in	Retained	Accumulated Other Comprehensive	Total Stockholders'
(In thousands)	Shares	Amount	Capital	Earnings	Loss	Equity
September 30, 2009	64,236	$64,236	$122,457	$915,600	$ —	$1,102,293
Net income	—	—	—	256,996	—	256,996
Restricted stock awards	145	145	(145)		—	—
Exercise of employee stock options	62	62	785	—	—	847
Stock option and restricted stock award compensation expense	—	—	9,998	—	—	9,998
September 30, 2010	64,443	64,443	133,095	1,172,596	—	1,370,134
Net income	—	—	—	271,674	—	271,674
Other comprehensive loss	—	—	—	—	(1,527)	(1,527)
Restricted stock awards	102	102	(102)		—	—
Exercise of employee stock options	415	415	5,777	—	—	6,192
Stock option and restricted stock award compensation expense	—	—	6,314	—	—	6,314
September 30, 2011	64,960	64,960	145,084	1,444,270	(1,527)	1,652,787
Net income	—	—	—	272,171	—	272,171
Other comprehensive loss	—	—	—	—	(1,484)	(1,484)
Restricted stock awards	207	207	(207)	—	—	—
Exercise of employee stock options	285	285	5,261	—	—	5,546
Stock option and restricted stock award compensation expense		—	10,402	—	—	10,402
September 30, 2012	65,452	$65,452	$160,540	$1,716,441	$ (3,011)	$1,939,422

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

NOTE 1—NATURE OF OPERATIONS

Atwood Oceanics, Inc. and its subsidiaries, which are collectively referred to herein as the “Company,” “we,” “us” or “our” except where stated or the context indicates otherwise, are a global offshore drilling contractor engaged in the drilling and completion of exploratory and developmental oil and gas wells. We currently own a diversified fleet of 11 mobile offshore drilling units located in the U.S. Gulf of Mexico, the Mediterranean Sea, offshore West Africa, offshore Southeast Asia and offshore Australia and are constructing three ultra-deepwater drillships and two high specification jackup rigs for delivery in fiscal year 2013 through 2015. We were founded in 1968 and are headquartered in Houston, Texas with support offices in Australia, Malaysia, Singapore and the United Kingdom.

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of Atwood Oceanics, Inc. and all of its domestic and foreign subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation.

Cash and cash equivalents

Cash and cash equivalents consist of cash in banks and highly liquid debt instruments, which mature within three months of the date of purchase.

Foreign exchange

The U.S. Dollar is the functional currency for all areas of our operations. Accordingly, monetary assets and liabilities denominated in foreign currency are re-measured to U.S. Dollars at the rate of exchange in effect at the end of the fiscal year, items of income and expense are re-measured at average monthly rates, and property and equipment and other nonmonetary amounts are re-measured at historical rates. Gains and losses on foreign currency transactions and re-measurements are included in contract drilling costs in our consolidated statements of operations. We recorded foreign exchange gains of $1.5 million during fiscal year 2012 and losses of $0.9 million and $0.1 million, during fiscal years 2011 and 2010, respectively. We did not disclose the effect of exchange rate changes on cash held in foreign currencies on the statement of cash flows due to the immaterial nature of the amounts.

Accounts receivable

We record accounts receivable at the amount we invoice our customers. Our portfolio of accounts receivable is comprised of major international corporate entities and government organizations with stable payment experience. Included within accounts receivable at September 30, 2012, and 2011 are unbilled receivable balances totaling $8.6 million and $1.1 million, respectively, which represent amounts for which services have been performed, revenue has been recognized based on contractual provisions and for which collection is deemed reasonably assured. Such unbilled amounts were billed subsequent to their respective fiscal year end. Historically, our uncollectible accounts receivable have been immaterial, and typically, we do not require collateral for our receivables. We provide an allowance for uncollectible accounts, as necessary, on a specific identification basis. We have allowance no allowance for doubtful accounts at September 30, 2012 and 2011.

Inventories of material and supplies

Inventories consist of spare parts, material and supplies held for consumption and are stated principally at average cost, net of reserves for excess and obsolete inventory of $2.6 million and $2.5 million at September 30, 2012, and 2011, respectively. To the extent the cost of inventory is not recoverable, we recognize a loss.

Income taxes

Deferred income taxes are recorded to reflect the tax consequences on future years of differences between the tax basis of assets and liabilities and their financial reporting amounts at each year-end given the provisions of enacted tax laws in each respective jurisdiction. Deferred tax assets are reduced by a valuation allowance when, based upon management’s estimates, it is more likely than not that a portion of the deferred tax assets will not be realized in a future period. In addition, we accrue for income tax contingencies, or uncertain tax positions, that we believe are more likely than not exposures. See Note 7 for further discussion.

Property and equipment

Property and equipment are recorded at historical cost. Interest costs related to property under construction are capitalized as a component of construction costs. Interest capitalized during fiscal years 2012, 2011 and 2010 was \$32.9 million, \$8.2 million and \$3.9 million, respectively.

Once rigs and related equipment are placed in service, they are depreciated on the straight-line method over their estimated useful lives, with depreciation discontinued only during the period when a drilling unit is out-of-service while undergoing a significant upgrade that extends its useful life. Our estimated useful lives of our various classifications of assets are as follows:

	Years
Drilling vessels and related equipment	5-35
Drill pipe	3
Furniture and other	3-10

Maintenance, repairs and minor replacements are charged against income as incurred. Major replacements and upgrades are capitalized and depreciated over the remaining useful life of the asset, as determined upon completion of the work. The cost and related accumulated depreciation of assets sold, retired or otherwise disposed are removed from the accounts at the time of disposition, and any resulting gain or loss is reflected in the Consolidated Statements of Operations for the applicable periods.

Impairment of property and equipment

We periodically evaluate our property and equipment to determine whether their net carrying value is in excess of their net realizable value. In determining an asset's fair value, these evaluations are performed considering a number of factors such as estimated future cash flows, appraisals and current market value analysis. Assets are written down to their fair value if the carrying amount of the asset is not recoverable and exceeds its fair value.

Deferred drydocking costs

We defer the costs of scheduled drydocking and charge such costs to contract drilling expense over the period to the next scheduled drydocking (normally 30 months). At September 30, 2012, and 2011, deferred drydocking costs totaling \$3.2 million and \$2.2 million, respectively, were included in Deferred Costs in the accompanying Consolidated Balance Sheets.

Revenue recognition

We account for contract drilling revenue in accordance with the terms of the underlying drilling contract. These contracts generally provide that revenue is earned and recognized on a daily rate (i.e. “day rate”) basis, and day rates are typically earned for a particular level of service over the life of a contract. Day rate contracts can be performed for a specified period of time or the time required to drill a specified well or number of wells. Revenues from day rate drilling operations, which are classified under contract drilling services, are recognized on a per day basis as services are performed assuming collectability is reasonably assured.

Deferred fees and costs

Fees received as compensation for the relocating drilling rigs from one major operating area to another, equipment and upgrade costs reimbursed by the customer, as well as receipt of advance billings of day rates are recognized as earned during the expected term of the related drilling contract, as are the day rates associated with such contracts. However, fees received upon termination of a drilling contract are generally recognized as earned during the period termination occurs as the termination fee is usually conditional based on the occurrence of an event as defined in the drilling contract, such as not obtaining follow on work to the contract in progress or relocation beyond a certain distance when the contract is completed. If receipt of such fees are not conditional, they will be recognized as earned on a straight-line method over the expected term of the related drilling contract.

We defer the mobilization costs relating to moving a drilling rig to a new area, which are incurred prior to the commencement of the drilling operations and customer requested equipment purchases that will revert to the customer at the end of the applicable drilling contract. We amortize such costs on a straight-line basis over the expected term of the applicable drilling contract. Contract revenues and drilling costs are reported in the Consolidated Statements of Operations at their gross amounts.

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At September 30, 2012 and 2011, deferred fees associated with mobilization, related equipment purchases and upgrades and receipt of advance billings of day rates totaled $22.7 million and $9.6 million, respectively. At September 30, 2012 and 2011, deferred costs associated with mobilization and related equipment purchases and upgrades totaled $24.4 million and $2.8 million, respectively. Deferred fees and deferred costs are classified as current or long-term deferred credits and deferred costs, respectively, in the accompanying Consolidated Balance Sheets based on the expected term of the applicable drilling contracts.

Share-based compensation

Share-based compensation cost is measured at the grant date, based on the calculated fair value of the award, and is recognized as an expense over the requisite service period (generally the vesting period of the equity grant). See Note 3 for additional information regarding share-based compensation.

Earnings per common share

Basic EPS excludes dilution and is computed by dividing net income (loss) by the weighted-average number of common shares outstanding for the period. Diluted EPS reflects the assumed effect of the issuance of additional shares in connection with the exercise of stock options and vesting of restricted stock. We have also included the impact of pro forma deferred tax assets in calculating the potential windfall and shortfall tax benefits to determine the amount of diluted shares using the treasury stock method.

The computation of basic and diluted earnings per share for each of the past three fiscal years is as follows (in thousands, except per share amounts):

	Net Income	Shares	Per Share Amount	
Fiscal 2012				
Basic earnings per share	$272,171	65,267	$4.17	
Effect of dilutive securities—				
Stock options	—	514	(0.03	)
Diluted earnings per share	$272,171	65,781	$4.14	
Fiscal 2011				
Basic earnings per share	$271,674	64,754	$4.20	
Effect of dilutive securities—				
Stock options	—	649	(0.05	)
Diluted earnings per share	$271,674	65,403	$4.15	
Fiscal 2010				
Basic earnings per share	$256,996	64,391	$3.99	
Effect of dilutive securities—				
Stock options	—	637	(0.04	)
Diluted earnings per share	$256,996	65,028	$3.95	

The calculation of diluted earnings per share for fiscal years 2012, 2011 and 2010 exclude consideration of shares of common stock which may be issued in connection with outstanding stock options of 656,000, 664,000 and 500,000, respectively, because such options were anti-dilutive. These options could potentially dilute basic EPS in the future.

Use of estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States ("GAAP") requires management to make extensive use of estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

NOTE 3—SHARE-BASED COMPENSATION

Share-based compensation cost is measured at the grant date, based on the calculated fair value of the award, and is recognized as an expense over the requisite service period, which is generally the vesting period of the equity award.

On December 7, 2006, our board of directors adopted, and our stockholders subsequently approved on February 8, 2007, the Atwood Oceanics, Inc. 2007 Long-Term Incentive Plan (as amended, the “2007 Plan”). The effective date of the 2007 Plan was December 7, 2006, and awards may be made under the 2007 Plan through December 7, 2016. Under our 2007 Plan, up to 4,000,000 shares of common stock were authorized for issuance to eligible participants in the form of restricted stock awards or upon exercise of stock options granted pursuant to the 2007 Plan. We also maintain one other stock incentive plan approved by our shareholders, the Atwood Oceanics, Inc. Amended and Restated 2001 Stock Incentive Plan (as amended, the “2001 Plan”), under which up to 4,000,000 shares of common stock were authorized for issuance to eligible participants in the form of restricted stock awards or upon exercise of stock options granted. No additional options or restricted stock have been available for award under the 2001 Plan since the implementation of the 2007 Plan. All stock incentive plans currently in effect have been approved by our shareholders.

A summary of shares available for issuance and outstanding stock option and restricted stock awards for our two stock incentive plans as of September 30, 2012 is as follows:

	2007 Plan	2001 Plan
Shares available for future awards or grants	1,048,399	—
Outstanding stock option grants	994,525	448,450
Outstanding unvested restricted stock awards	700,508	—

Awards of restricted stock and stock options have both been granted under our stock incentive plans as of September 30, 2012. We deliver newly issued shares of common stock for restricted stock awards upon vesting and upon exercise of stock options.

We recognize compensation expense on grants of share-based compensation awards on a straight-line basis over the required service period for each award. Unrecognized compensation cost, net of estimated forfeitures, related to awards of stock options and restricted stock and the related remaining weighted-average service period is as follows (in thousands, except average service periods):

	September 30, 2012	2011
Unrecognized Compensation Cost		
Stock options	$6,484	$4,964
Restricted stock awards	12,999	6,575
Total	$19,483	$11,539
Remaining weighted average service period (Years)	2.2	2.3

Stock Options

Under our stock incentive plans, the exercise price of each stock option must be equal to or greater than the fair market value of one share of our common stock on the date of grant, with all outstanding options having a maximum term of 10 years. Options vest ratably over a period ranging from the end of the first to the fourth year from the date of grant for stock options. Each option is for the purchase of one share of our common stock.

The total fair value of stock options vested during fiscal years 2012, 2011 and 2010 was $2.5 million, $2.7 million and $3.0 million, respectively. The per share weighted-average grant-date fair value of stock options granted during fiscal years 2012, 2011 and 2010 was $16.90, $15.72 and $14.69, respectively. We estimate the fair value of each stock option on the date of grant using the Black-Scholes pricing model and the following assumptions:

	Fiscal 2012	Fiscal 2011	Fiscal 2010
Risk-Free Interest Rate	0.9 %	1.9 %	2.1 %
Expected Volatility	44 %	44 %	43 %
Expected Life (Years)	5.4	5.2	5.3
Dividend Yield	None	None	None

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The average risk-free interest rate is based on the five-year U.S. treasury security rate in effect as of the grant date. We determined expected volatility using a six-year historical volatility figure and determined the expected term of the stock options using 10 years of historical data. The expected dividend yield is based on the expected annual dividend as a percentage of the market value of our common stock as of the grant date.

A summary of stock option activity for fiscal year 2012 is as follows:

	Number of Options (000s)	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (000s)
Outstanding at October 1, 2011	1,480	$25.44	—	$—
Granted	320	$41.60		
Exercised	(285)	$19.39		$7,944
Forfeited	(65)	$36.60		
Outstanding at September 30, 2012	1,450	$29.74	6.1	$22,663
Exercisable at September 30, 2012	855	$23.95	4.5	$18,378

Restricted Stock

We have awarded restricted stock under the 2007 Plan to certain employees and to our non-employee directors. All current awards of restricted stock to employees are subject to a vesting and restriction period ranging from three to four years, subject to early termination as provided in the 2007 Plan. In addition, certain awards of restricted stock to employees are subject to market-based performance conditions. The number of market-based performance restricted shares that vest will depend on the degree of achievement of specified corporate performance criteria which are strictly market-based. All awards of restricted stock to non-employee directors are subject to a vesting and restriction period of a minimum of 13 months, subject to early termination as provided in the 2007 Plan. We value restricted stock awards based on the fair market value of our common stock on the date of grant and also adjust fair market value for any awards subject to market-based performance conditions, where applicable.

A summary of restricted stock activity for fiscal year 2012 is as follows:

	Number of Shares (000s)	Weighted Average Fair Value
Unvested at October 1, 2011	560	$34.54
Granted	392	$41.36
Vested	(207)	$33.07
Forfeited	(44)	$38.49
Unvested at September 30, 2012	701	$38.54

NOTE 4—PROPERTY AND EQUIPMENT

A summary of property and equipment by classification is as follows (in thousands):

	September 30, 2012	2011
Drilling vessels and equipment	$2,523,895	$1,578,592
Construction work in progress	438,081	736,827
Drill pipe	20,576	18,182
Office equipment and other	19,610	8,800
Cost	3,002,162	2,342,401
Less: Accumulated depreciation	(464,822)	(455,080)
Drilling and other property and equipment, net	$2,537,340	$1,887,321

New Construction Projects

During fiscal year 2008, we entered into construction contracts with Jurong Shipyard Pte. Ltd. to construct two Friede & Goldman ExD Millennium semisubmersible drilling units (the Atwood Osprey and the Atwood Condor). The Atwood Osprey was delivered in April 2011, and the Atwood Condor was delivered in June 2012.

In October 2010, we entered into turnkey construction agreements with PPL Shipyard PTE LTD in Singapore (“PPL”) to construct two Pacific Class 400 jackup drilling units (the Atwood Mako and the Atwood Manta). The Atwood Mako was delivered in August 2012 and the Atwood Manta is scheduled for delivery in late November 2012.

In January 2011, we exercised an option agreement and entered into a turnkey construction agreement with PPL to construct a third Pacific Class 400 jackup drilling unit (the Atwood Orca). The Atwood Orca is scheduled for delivery in June 2013.

In January 2011, we entered into a turnkey construction contract with Daewoo Shipbuilding and Marine Engineering Co., Ltd (“DSME”) to construct an ultra-deepwater drillship, the Atwood Advantage, at the DSME yard in South Korea. The Atwood Advantage is scheduled for delivery in September 2013.

In October 2011, we entered into a turnkey construction contract with DSME to construct an ultra-deepwater drillship, the Atwood Achiever, at the DSME yard in South Korea. The Atwood Achiever is expected to be delivered in June 2014.

In September 2012, we entered into a turnkey construction contract with DSME to construct a third ultra-deepwater drillship, the Atwood Admiral, at the DSME yard in South Korea. The Atwood Admiral is expected to be delivered in March 2015.

As of September 30, 2012, we had expended approximately $438 million towards the construction of our five drilling units under construction. Total remaining firm commitments for our five drilling units under construction were approximately $1.6 billion at September 30, 2012.

NOTE 5—LONG-TERM DEBT

A summary of long-term debt is as follows (in thousands):

	September 30, 2012	September 30, 2011
Senior Notes, bearing fixed interest at 6.5% per annum	$450,000	$—
Credit Facility, bearing interest at approximately 3.2%[(1)] per annum at September 30, 2012 and 3.1%[(1)] per annum at September 30, 2011.	380,000	520,000
	$830,000	$520,000

(1) After the impact of our interest rate swaps.

Senior Notes

In January 2012, we issued $450 million aggregate principal amount of our 6.50% Senior Notes due 2020 (the "Notes"). We received net proceeds, after deducting underwriting discounts and offering expenses, of approximately $440 million. We used the net proceeds to reduce outstanding borrowings under our credit facility.

The Notes are our senior unsecured obligations and are not currently guaranteed by any of our subsidiaries. Interest is payable on the Notes semi-annually in arrears. The indenture governing the Notes contains provisions that limit our ability and the ability of our restricted subsidiaries to incur or guarantee additional indebtedness or issue preferred stock; pay dividends or make other restricted payments; sell assets; make investments; create liens; enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us; and consolidate, merge or transfer all or substantially all of our assets. Many of these restrictions will terminate if the Notes become rated investment grade. The indenture governing the Notes also contains customary events of default, including payment defaults; defaults for failure to comply with other covenants in the indenture; cross-acceleration and entry of final judgments in excess of $50.0 million; and certain events of bankruptcy, in certain cases subject to notice and grace periods. We are required to offer to repurchase the Notes in connection with specified change in control events or with excess proceeds of asset sales not applied for permitted purposes.

At any time prior to February 1, 2015, we may, on any one or more occasions, redeem up to 35% of the aggregate principal amount of the Notes with the net cash proceeds of certain equity offerings at a redemption price set forth in the indenture governing the Notes. At any time prior to February 1, 2016, we may, on any one or more occasions, redeem the Notes in whole or in part at a redemption price equal to 100% of the principal amount of the Notes redeemed plus a "make whole" premium. On and after February 1, 2016, we may, on any one or more occasions, redeem the Notes in whole or in part at the redemption price set forth in the indenture governing the Notes.

Revolving Credit Facility

As of September 30, 2012, we had $380 million of outstanding borrowings under our five-year $750 million senior secured revolving credit facility, which was entered into in May 2011. Our wholly-owned subsidiary, Atwood Offshore Worldwide Limited ("AOWL"), is the borrower under the credit facility, and we and certain of our other subsidiaries are guarantors under the facility. Borrowings under the credit facility bear interest at the Eurodollar rate plus a margin of 2.50%. Certain borrowings effectively bear interest at a fixed rate due to our interest rate swaps. See Note 6. The average interest rate for borrowings under the credit facility was approximately 3.2% per annum at September 30, 2012, after considering the impact of our interest rate swaps. The credit facility also provides for the issuance, when required, of standby letters of credit. The credit facility has a commitment fee of 1.0% per annum on the unused portion of the underlying commitment. As of September 30, 2012, we had standby letters of credit issued in the aggregate amount of $0.1 million. As of November 15, 2012, an additional $155 million had been borrowed under our credit facility subsequent to September 30, 2012, leaving $215 million of available borrowing capacity under the facility. Subject to the satisfaction of certain conditions precedent and the agreement by the lenders, the credit facility includes an "accordion" feature which, if exercised, will increase total commitments by up to $550 million, bringing the total commitment to $1.3 billion.

The credit facility contains various financial covenants that impose a maximum leverage ratio of 4.0 to 1.0, a debt to capitalization ratio of 0.5 to 1.0, a minimum interest expense coverage ratio of 3.0 to 1.0 and a minimum collateral maintenance of 150% of the aggregate amount outstanding under the credit facility. In addition, the credit facility contains limitations on our and certain of our subsidiaries' ability to incur liens; merge, consolidate or sell substantially all assets; pay dividends (including restrictions on AOWL's ability to pay dividends to us); incur additional indebtedness; make advances, investments or loans; and transact with affiliates. The credit facility also contains customary events of default, including but not limited to delinquent payments, bankruptcy filings, material adverse judgments, guarantees or security documents not being in full effect, non-compliance with the Employee Retirement Income Security Act of 1974, cross-defaults under other debt agreements, or a change of control. The credit facility is secured primarily by first preferred mortgages on six of our active drilling units (the Atwood Aurora, the Atwood Beacon, the Atwood Eagle, the Atwood Falcon, the Atwood Hunter, and the Atwood Osprey), as well as liens on the equity interests of our subsidiaries that own, directly or indirectly, such drilling units. In addition, if we exercise the accordion feature and increase the total commitments, the credit facility requires that we provide a first preferred mortgage on the Atwood Condor, the Atwood Mako and the Atwood Manta, as well as a lien on the equity interests of our subsidiaries that own, directly or indirectly, such rigs. We were in compliance with all financial covenants under the credit facility at September 30, 2012.

As of September 30, 2012, five $50.0 million notional interest rate swap agreements were in effect to fix the interest rate on $250 million of our borrowings under the credit facility at approximately 3.4% through September 2014.

NOTE 6—INTEREST RATE SWAPS

Our credit facility exposes us to short-term changes in market interest rates as our interest obligations on these instruments are periodically re-determined based on the prevailing Eurodollar rate. We enter into interest rate swaps to limit our exposure to fluctuations and volatility in interest rates. We do not engage in derivative transactions for speculative or trading purposes and we are not a party to leveraged derivatives.

At September 30, 2012, we had five $50.0 million notional interest rate swaps in effect. These interest rate swaps fix the interest on $250 million in borrowings at 3.4% through September 2014.

Fair Value of Derivatives

The following table presents the carrying amount of our cash flow hedge derivative contracts included in the Consolidated Balance Sheets as of September 30, 2012 and 2011 (in thousands):

		September 30,	
Type of Contract	Balance Sheet Classification	2012	2011
Short term interest rate swaps	Accrued liabilities	$1,705	$988
Long term interest rate swaps	Other long-term liabilities	1,414	631
Total derivative contracts, net		$3,119	$1,619

We record the interest rate derivative contracts at fair value on our consolidated balance sheets (See Note 10). Hedging effectiveness is evaluated each quarter end using the “Dollar Off-Set Method”. Each quarter, changes in the fair values will adjust the balance sheet asset or liability, with an offset to Other Comprehensive Income (“OCI”) for the effective portion of the hedge.

We recognized a loss of approximately $1.5 million in OCI as a result of changes in fair value of our interest rate derivatives during the fiscal year ended September 30, 2012, net of loss realized from hedge ineffectiveness and net of $1.2 million of realized losses associated with effective portion and classified as interest expense, net of capitalized interest on our Consolidated Statement of Operations. A $1.5 million loss was also recognized in OCI during the fiscal year ended September 30, 2011, net of $0.4 million of realized losses associated with effective portion and classified as interest expense, net of capitalized interest on our Consolidated Statement of Operations.

For interest rate swaps, we evaluate all material terms between the swap and the underlying debt obligation. Any change in fair value resulting from ineffectiveness is recognized immediately in earnings. For the fiscal year ended September 30, 2012, we recognized a $0.4 million loss on our condensed consolidated statement of operations due to hedge ineffectiveness and no loss due to hedge ineffectiveness for the fiscal year ended September 30, 2011.

NOTE 7—INCOME TAXES

Domestic and foreign income before income taxes for the three-year period ended September 30, 2012, is as follows (in thousands):

	Fiscal 2012	Fiscal 2011	Fiscal 2010
Domestic loss	$(35,685)	$(22,954)	$(24,550)
Foreign income	348,989	347,801	344,529
	$313,304	$324,847	$319,979

The provision (benefit) for domestic and foreign taxes on income consists of the following (in thousands):

	Fiscal 2012	Fiscal 2011	Fiscal 2010
Current—domestic	$(1,048)	$29	$(34)
Deferred—domestic	(980)	(980)	6,813
Current—foreign	43,169	54,209	58,218
Deferred—foreign	(8)	(85)	(2,014)
	$41,133	$53,173	$62,983

Deferred Taxes

The components of the deferred income tax assets (liabilities) as of September 30, 2012 and 2011 are as follows (in thousands):

	September 30, 2012	2011
Deferred tax assets—		
Net operating loss carryforwards	$26,067	$16,014
Tax credit carryforwards	1,246	1,618
Stock option compensation expense	8,047	7,105
Book accruals	4,859	3,273
	40,219	28,010
Deferred tax liabilities—		
Difference in book and tax basis of equipment	(10,572)	(12,222)
	(10,572)	(12,222)
Net deferred tax assets (liabilities) before valuation allowance	29,648	15,788
Valuation allowance	(38,439)	(25,568)
	$(8,791)	$(9,780)
Net current deferred tax assets	$—	$—
Net noncurrent deferred tax liabilities	(8,791)	(9,780)
	$(8,791)	$(9,780)

For fiscal year 2012, we recorded a valuation allowance of $12.9 million on net deferred tax assets primarily related to our United States net operating loss carry forward. The gross amount of federal net operating loss carry forwards as of September 30, 2012 is estimated to be $116.7 million, which will begin to expire in 2025. Management does not expect that our tax credit carry forward of $1.2 million will be utilized to offset future tax obligations before the credits begin to expire in 2013. Thus, a corresponding valuation allowance of $1.2 million is recorded as of September 30, 2012.

We have approximately $14.6 million of windfall tax benefits from previous stock option exercises that have not been recognized as of September 30, 2012. This amount will not be recognized until the deduction would reduce our United States income taxes payable. At such time, the amount will be recorded as an increase to paid-in-capital. We apply the "with-and-without" approach when utilizing certain tax attributes whereby windfall tax benefits are used last to offset taxable income.

We do not record federal income taxes on the undistributed earnings of our foreign subsidiaries that we consider to be permanently reinvested in foreign operations. The cumulative amount of such undistributed earnings was approximately $1.6 billion at September 30, 2012. If these earnings were distributed, we estimate approximately $270 million in additional taxes would be incurred. These earnings could also become subject to additional taxes under the anti-deferral provisions within the U.S. Internal Revenue Code. However, we believe this is highly unlikely given our current structure and have not provided deferred income taxes on these foreign earnings as we consider them to be permanently invested abroad.

We record estimated accrued interest and penalties related to uncertain tax positions in income tax expense. At September 30, 2012, we had approximately $8.2 million of reserves for uncertain tax positions, including estimated accrued interest and penalties of $2.5 million, which are included in Other Long Term Liabilities in the Consolidated Balance Sheet. All $8.2 million of the net uncertain tax liabilities would affect the effective tax rate if recognized. A summary of activity related to the net uncertain tax positions including penalties and interest for fiscal year 2012 is as follows:

	Liability for Uncertain Tax Positions
Balance at October 1, 2011	$ 16,804
Decreases due to the resolution of prior period tax examinations	(8,640)
Balance at September 30, 2012	$ 8,164

Our United States tax returns for fiscal year 2009 and subsequent years remain subject to examination by tax authorities. As we conduct business globally, we have various tax years remaining open to examination in our international tax jurisdictions, including tax returns in Australia for fiscal years 2007 through 2012, as well as returns in Equatorial Guinea for calendar years 2008 through 2011. Although we cannot predict the outcome of ongoing or future tax examinations, we do not anticipate that the ultimate resolution of these examinations will have a material impact on our consolidated financial position, results of operations or cash flows.

As a result of working in foreign jurisdictions, we earned a high level of operating income in certain nontaxable and deemed profit tax jurisdictions, which significantly reduced our effective tax rate for fiscal years 2012, 2011 and 2010 when compared to the United States statutory rate. There were no significant transactions that materially impacted our effective tax for fiscal years 2012, 2011 or 2010. The differences between the United States statutory and our effective income tax rate are as follows:

	Fiscal 2012	Fiscal 2011	Fiscal 2010
Statutory income tax rate	35 %	35 %	35 %
Resolution of prior period tax items	(3)	—	1
Increase in tax rate resulting from—			
Valuation allowance	4	2	2
Increases to the reserve for uncertain tax positions	—	2	1
Decrease in tax rate resulting from—			
Foreign tax rate differentials, net of foreign tax credit utilization	(23)	(23)	(19)
Effective income tax rate	13 %	16 %	20 %

NOTE 8—CAPITAL STOCK

Preferred Stock

We are authorized to issue 1.0 million shares of preferred stock with no par value. In October 2002, we designated Series A Junior Participating Preferred Stock in connection with the Rights Agreement described below. No preferred shares have been issued.

Rights Agreement

In September 2002, we authorized and declared a dividend of one Right (as defined in the Rights Agreement dated effective October 18, 2002 between us and Continental Stock Transfer & Trust Company, as rights agent, which governs the Rights) for each outstanding share of common stock as of November 5, 2012, subject to lender approval and consent, which was obtained. Effective as of the close of business on November 5, 2012, the rights agreement expired in accordance with its terms. As a result, the stock purchase rights under the rights agreement have been terminated and are no longer effective.

NOTE 9—RETIREMENT PLANS

We have two defined contribution retirement plans (the “Retirement Plans”) under which qualified participants may make contributions, which together with our contributions, can be up to 100% of their compensation, as defined, to a maximum of $49,000. In the first month following the date of hire, an employee can elect to become a participant in a Retirement Plan. Under the Plans, participant contributions of 1% to 5% are matched on a 2 to 1 basis. Our contributions vest 100% to each participant after three years of service with us including any period of ineligibility mandated by the Plans. If a participant terminates employment before becoming fully vested, the unvested portion is credited to our account and can be used only to offset our future contribution requirements.

During fiscal years 2012, 2011 and 2010, forfeitures of $0.2 million, $0.3 million, and $0.3 million, respectively, were used to reduce our cash contribution requirements. In fiscal years 2012, 2011 and 2010, our actual cash contributions totaled approximately $4.6 million, $4.3 million and $5.2 million, respectively. As of September 30, 2012, there were approximately $0.2 million of contribution forfeitures, which can be used to reduce our future cash contribution requirements.

NOTE 10—FAIR VALUE OF FINANCIAL INSTRUMENTS

We have certain assets and liabilities that are required to be measured and disclosed at fair value in accordance with generally accepted accounting principles (“GAAP”). Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date.

The established GAAP fair value hierarchy prioritizes inputs to valuation techniques used to measure fair value into three levels. Priority is given to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Assets and liabilities measured at fair value are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values, stated below, takes into account the market for our financial assets and liabilities, the associated credit risk and other considerations.

We have classified and disclosed fair value measurements using the following levels of the fair value hierarchy:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities.

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.

Level 3: Measurement based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable for objective sources (i.e., supported by little or no market activity).

Fair value of Certain Assets and Liabilities

The fair value of cash and cash equivalents, accounts receivable and accounts payable approximate fair value because of their short term maturities.

Fair Value of Financial Instruments

The fair value of financial instruments is determined by using quoted market prices when available. When quoted prices are not available, independent third party services may be used to determine the fair value with reference to observable inputs used. When independent third party services are used, we obtain an understanding of how the fair values are derived and selectively corroborate fair values by reviewing other readily available market based sources of information. Valuation policies

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and procedures are determined and monitored by our treasury department, which reports to our Senior Vice-President and Chief Financial Officer.

The following table sets forth the estimated fair value of certain financial instruments at September 30, 2012, which are measured and recorded at fair value on a recurring basis:

(in thousands)		Fair Value Measurements				
Type of Contract	Balance Sheet Classification	September 30, 2012				
		Carrying Amount	Level 1	Level 2	Level 3	Estimated Fair Value
Short term interest rate swaps	Accrued liabilities	$1,705	$—	$1,705	$—	$1,705
Long term interest rate swaps	Other long-term liabilities	1,414	—	1,414	—	1,414
Total derivative contracts, net		$3,119	$—	$3,119	$—	$3,119
		September 30, 2011				
Short term interest rate swaps	Accrued liabilities	$988	$—	$988	$—	$988
Long term interest rate swaps	Other long-term liabilities	631	—	631	—	631
Total derivative contracts, net		$1,619	$—	$1,619	$—	$1,619

Interest rate swaps - The fair values of our interest rate swaps are based upon valuations calculated by an independent third party. The derivatives were valued according to the "Market approach" where possible, and the "Income approach" otherwise. A third party independently valued each instrument using forward price data supplied by dealers and the Chicago Mercantile Exchange (the exchange on which similar derivatives trade) indexed to one month USD LIBOR as of September 28, 2012, and broker quotes for credit default swaps or related credit instruments. It was determined that the contribution of the credit valuation adjustment to total fair value is less than 3.0% for all derivatives and is therefore not significant. Based on valuation inputs for fair value measurement and independent review performed by third party consultants, we have classified our derivative contracts as Level 2.

Long-term Debt - Our long-term debt consists of both our Notes and our credit facility.

Credit Facility - The carrying amounts of our variable-rate debt approximates fair value because such debt bears short-term, market-based interest rates. We have classified this instrument as Level 2 as valuation inputs for purposes of determining our fair value disclosure are readily available published Eurodollar rates.

Notes - The carrying value of our Notes is $450 million while the fair value of those Notes is $478.0 million, based upon a valuation calculated by an independent third party. The third party conducted independent research concerning interest rates and credit risk and relied on market sources to assess the LIBOR swap curve data as well as information provided in the debt purchase agreement. We have classified this instrument as Level 2 as valuation inputs for fair value measurements are quoted market prices that can only be obtained from independent third party sources on September 30, 2012. The fair value amount has been calculated using these quoted prices. However, no assurance can be given that the fair value would be the amount realized in an active market exchange.

NOTE 11—CONCENTRATION OF MARKET AND CREDIT RISK

All of our customers are in the oil and gas offshore exploration and production industry. This industry concentration has the potential to impact our overall exposure to market and credit risks, either positively or negatively, in that our customers could be affected by similar changes in economic, industry or other conditions. However, we believe that the credit risk posed by this industry concentration is offset by the creditworthiness of our customer base.

Revenues from significant customers are as follows (in thousands):

	Fiscal 2012	Fiscal 2011	Fiscal 2010
Chevron Australia	$265,731	$199,685	$81,577
Sarawak Shell Bhd.	44,405	138,836	84,617
Kosmos Energy Ghana Inc.	90,088	136,205	90,936
Noble Energy Inc.	137,135	—	—

NOTE 12—COMMITMENTS AND CONTINGENCIES

Operating Leases

Future minimum lease payments for operating leases for fiscal years ending September 30 are as follows (in thousands):

2013	$2,603
2014	$3,588
2015	$2,329
2016	$1,825
2017 and thereafter	$12,980

Total rent expense under operating leases was approximately $5.5 million, $4.4 million and $4.8 million for fiscal years ended September 30, 2012, 2011, and 2010, respectively.

Purchase Commitments

At September 30, 2012, our purchase commitments, relating to our five drilling units under construction, were as follows (in thousands):

2013	$454,000
2014	$731,000
2015	$369,000
2016	$—
2017 and thereafter	$—

Litigation

We are party to a number of lawsuits which are ordinary, routine litigation incidental to our business, the outcome of which is not expected to have, either individually or in the aggregate, a material adverse effect on our financial position, results of operations or cash flows.

Other Matters

The Atwood Beacon operated in India from early December 2006 to the end of July 2008. A service tax in India was enacted in 2004 on revenues derived from seismic and exploration activities. This service tax law was subsequently amended in June 2007 and again in May 2008 to state that revenues derived from mining services and drilling services were specifically subject to this service tax. The contract terms with our customer in India provided that any liability incurred by us related to any taxes pursuant to laws not in effect at the time the contract was executed in 2005 was to be reimbursed by our customer. We believe any service taxes assessed by the Indian tax authorities under the 2007 or 2008 amendments are an obligation of our customer. Our customer is disputing this obligation on the basis that revenues derived from drilling services were taxable under the initial 2004 law and are, therefore, our obligation.

After reviewing the status of the drilling service we provided to our customer, the Indian tax authorities assessed service tax obligations on revenues derived from the Atwood Beacon commencing on June 1, 2007. The relevant Indian tax authority issued an extensive written ruling setting forth the application of the June 1, 2007 service tax regulation and confirming the position that drilling services, including the services performed under our contract with our customer prior to June 1, 2007, were not covered by the 2004 service tax law. In August 2012, the Indian Custom Excise and Service Tax Appellate Tribunal issued an Order in our favor confirming our position that service tax did not apply to drilling services performed prior to June 1, 2007. This ruling is subject to appeal to the Indian Supreme Court.

As of September 30, 2012, we had paid to the Indian government $10.1 million in service taxes and have accrued $1.8 million of additional service tax obligations in accrued liabilities on our consolidated balance sheets, for a total of $11.9 million relating to service taxes. We recorded a corresponding $11.9 million long-term other receivable due from our customer relating to service taxes due under the contract. We continue to pursue collection of such amounts from our customer.

NOTE 13—SUPPLEMENTAL CASH FLOW INFORMATION

	Years Ended September 30,		
	2012	2011	2010
Cash paid during the period for:			
Domestic and foreign income taxes	$49,636	$55,062	$65,024
Interest, net of amounts capitalized	$1,849	$3,003	$1,656
Non-cash activities:			
Increase (decrease) in accounts payable and accrued liabilities related to capital expenditures	$(56,965)	$77,164	$10,616

NOTE 14—RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In December 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2011-12, "Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in ASU Update 2011-05" (Topic 220) to effectively defer only those changes in ASU Update 2011-05 that relate to the presentation of reclassification adjustments out of accumulated other comprehensive income. The amendments in this update supersede changes to those paragraphs in ASU 2011-05 that pertain to how, when, and where reclassification adjustments are presented. The amendments will be temporary to allow the FASB time to deliberate the presentation requirements for reclassifications out of accumulated other comprehensive income for annual and interim financial statements. The amendments in this update are effective at the same time as the amendments in ASU 2011-05 so that entities will not be required to comply with the presentation requirements in ASU 2011-05 that this update is deferring. We adopted the amendments in ASU 2011-05 on June 30, 2011 with no material impact on our consolidated financial statements or disclosures in our financial statements.

In December 2011, the FASB issued ASU 2011-11, "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities" for an entity to provide enhanced disclosures that will enable users of its financial statements to evaluate the effect or potential effect of netting arrangements on an entity's financial position. An entity is required to apply the amendments for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. An entity should provide the disclosures required by those amendments retrospectively for all comparative periods presented. We will adopt the accounting standards effective January 1, 2013. We do not expect that our adoption will have a material effect on our financial statements.

NOTE 15—OPERATIONS BY GEOGRAPHIC AREAS

We report our offshore contract drilling operation as a single reportable segment: Offshore Contract Drilling Services. The consolidation of our offshore contract drilling operations into one reportable segment is attributable to how we manage our business, including the nature of services provided and the type of customers of such services and the fact that all of our drilling fleet are dependent upon and able to service the worldwide oil industry. The mobile offshore drilling units and related equipment comprising our offshore rig fleet operate in a single, global market for contract drilling services and are often redeployed globally due to changing demands of our customers, which consist largely of major integrated oil and natural gas companies and independent oil and natural gas companies. Our offshore contract drilling services segment currently conducts offshore contract drilling operations located in the U.S. Gulf of Mexico, the Mediterranean Sea, offshore West Africa, offshore Southeast Asia and offshore Australia.

The accounting policies of our reportable segment are the same as those described in the summary of significant accounting policies (see Note 2). We evaluate the performance of our operating segment based on revenues from external customers and segment profit. A summary of revenues for the fiscal years ended September 30, 2012, 2011 and 2010 and long-lived assets by geographic areas as of September 30, 2012, 2011 and 2010 is as follows (in thousands):

	Fiscal 2012	Fiscal 2011	Fiscal 2010
REVENUES:			
Australia	$363,400	$199,685	$134,112
Cameroon	35,362	625	—
Cote d'Ivoire	—	—	7,953
Egypt	—	28,486	46,622
Equatorial Guinea	126,575	47,271	114,660
Ghana	90,076	136,206	136,012
Guyana	31,675	73	—
Israel	6,301	—	—
Malaysia	44,413	138,836	103,959
Singapore	—	14,607	49,985
Suriname	13,488	45,060	—
Thailand	39,598	34,274	34,236
Tunisia	—	(156)	12,958
United States	36,533	109	10,065
TOTAL REVENUES	$787,421	$645,076	$650,562

	Fiscal 2012	Fiscal 2011	Fiscal 2010
TOTAL PROPERTY AND EQUIPMENT, NET:			
Australia	$738,504	$697,450	$77,223
Cameroon	235,573	186,224	—
Cote d'Ivoire	—	—	88,022
Egypt	23	43	188,780
Equatorial Guinea	3	61,454	66,460
Ghana	5,475	7,549	9,633
Indonesia	4	4	4
Israel	81,173	—	—
Korea	353,641	161,996	—
Malaysia	169	52,405	56,144
Malta	4,768	5,443	6,091
Singapore	84,443	572,911	787,529
Suriname	—	84,301	—
Thailand	208,303	19,127	21,023
United Kingdom	1	1	1
United States	825,260	38,413	43,051
TOTAL PROPERTY AND EQUIPMENT, NET	$2,537,340	$1,887,321	$1,343,961

NOTE 16—QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly results for fiscal years 2012 and 2011 are as follows (in thousands, except per share amounts):

	Quarters ended (1)			
	December 31	March 31	June 30	September 30
Fiscal 2012				
Revenues	$184,672	$171,621	$178,603	$252,525
Income before income taxes	77,931	63,492	61,990	109,891
Net income	65,468	59,466	51,711	95,526
Earnings per common share—				
Basic	1.01	0.91	0.79	1.46
Diluted	1.00	0.90	0.79	1.45
Fiscal 2011				
Revenues	$146,286	$159,085	$162,147	$177,558
Income before income taxes	63,240	90,485	87,203	83,919
Net income	52,850	70,611	75,285	72,928
Earnings per common share—				
Basic	0.82	1.09	1.16	1.13
Diluted	0.81	1.08	1.15	1.12

(1) The sum of the individual quarterly net income per common share amounts may not agree with year-to-date net income per common share as each quarterly computation is based on the weighted average number of common shares outstanding during that period.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures as of the end of the period covered by this report have been designed and are effective at the reasonable assurance level so that the information required to be disclosed by us in our periodic SEC filings is recorded, processed, summarized and reported within the time periods specific in the SEC's rules, regulations, and forms and is communicated to management. We believe that a controls system, no matter how well designed and operated, cannot provide absolute assurance that the objectives of the controls system are met, and no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within a company have been detected.

(b) Management's Annual Report on Internal Control over Financial Reporting

A copy of our Management's Report on Internal Control over Financial Reporting is included in Item 8 of this Form 10-K.

(c) Attestation Report of the Independent Registered Public Accounting Firm.

A copy of the report of PricewaterhouseCoopers LLP, our independent registered public accounting firm, is included in Item 8 of this Form 10-K

(d) Change in Internal Control over Financial Reporting

No change in our internal control over financial reporting occurred during the most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

This information is incorporated by reference from our definitive Proxy Statement for the 2013 Annual Meeting of Shareholders, to be filed with the SEC not later than 120 days after the end of the fiscal year covered by this Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

This information is incorporated by reference from our definitive Proxy Statement for the 2013 Annual Meeting of Shareholders, to be filed with the SEC not later than 120 days after the end of the fiscal year covered by this Form 10-K.

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

This information is incorporated by reference from our definitive Proxy Statement for the 2013 Annual Meeting of Shareholders, to be filed with the SEC not later than 120 days after the end of the fiscal year covered by this Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

This information is incorporated by reference from our definitive Proxy Statement for the 2013 Annual Meeting of Shareholders, to be filed with the SEC not later than 120 days after the end of the fiscal year covered by this Form 10-K.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

This information is incorporated by reference from our definitive Proxy Statement for the 2013 Annual Meeting of Shareholders, to be filed with the SEC not later than 120 days after the end of the fiscal year covered by this Form 10-K.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENTS

(1) Financial Statements.

Our Consolidated Financial Statements, together with the notes thereto and the report of PricewaterhouseCoopers LLP dated November 19, 2012, are included in Item 8 of this Form 10-K.

(2) Financial Statement Schedules.

All financial statement schedules have been omitted because they are not applicable or not required, the information is not significant, or the information is presented elsewhere in the financial statements.

(3) Exhibits.

3.1	Amended and Restated Certificate of Formation dated February 9, 2006 (Incorporated herein by reference to Exhibit 3.1 of our Form 10-Q filed for the quarter ended March 31, 2008).
3.2	Amendment No. 1 to Amended and Restated Certificate of Formation dated February 14, 2008 (Incorporated herein by reference to Exhibit 3.2. of our Form 10-Q for the quarter ended March 31, 2008).
3.3	By-Laws of Atwood Oceanics, Inc., effective May 24, 2012 (Incorporated herein by reference to Exhibit 3.1 to our Form 8-K filed on May 30, 2012).
4.1	Indenture dated January 18, 2012 between Atwood Oceanics, Inc. and Wells Fargo Bank, National Association, as trustee, relating to debt securities (Incorporated herein by reference to Exhibit 4.1 to our Form 10-Q for the quarter ended December 31, 2011).
4.2	First Supplemental Indenture dated January 18, 2012 between Atwood Oceanics, Inc. and Wells Fargo Bank, National Association, as trustee, including the form of 6.50% Senior Notes due 2020 (Incorporated herein by reference to Exhibit 4.2 to our Form 10-Q for the quarter ended December 31, 2011).
4.3	See Exhibit Nos. 3.1, 3.2 and 3.3 hereof for provisions of our Amended and Restated Certificate of Formation (as amended) and By-Laws defining the rights of our shareholders (Incorporated herein by reference to Exhibits 3.1 and 3.2 of our Form 10-Q for the quarter ended March 31, 2008 and Exhibit 3.1 to our Form 8-K filed on May 30, 2012).
	The Company and its subsidiaries are parties to several debt instruments that have not been filed with the SEC under which the total amount of securities authorized does not exceed 10% of the total assets of the Company and its subsidiaries on a consolidated basis. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, the Company agrees to furnish a copy of such instruments to the SEC upon request.
†10.1	Atwood Oceanics, Inc. Amended and Restated 2001 Stock Incentive Plan (Incorporated herein by reference to Appendix D to our definitive proxy statement on Form DEF 14A filed January 13, 2006).
†10.2	Form of Atwood Oceanics, Inc. Stock Option Agreement – 2001 Stock Incentive Plan (Incorporated herein by reference to Exhibit 10.3.7 of our Form 10-K for the year ended September 30, 2005).
†10.3	Form of Atwood Oceanics, Inc. Restricted Stock Award Agreement – 2001 Stock Incentive Plan (Incorporated herein by reference to Exhibit 10.3.8 of our Form 10-K for the year ended September 30, 2005).
†10.4	

	Form of Non-Employee Director Restricted Stock Award Agreement Amended and Restated 2001 Stock Incentive Plan (Incorporated herein by reference to Exhibit 10.1 of our Form 8-K filed June 1, 2006).
†10.5	Non-Employee Directors' Elective Deferred Compensation Plan effective December 1, 2007 (Incorporation herein by reference to Exhibit 10.1 of our Form 8-K filed November 14, 2007).
†10.6	Atwood Oceanics, Inc. 2007 Long-Term Incentive Plan (Incorporated herein by reference to Appendix B to our definitive proxy statement on Form DEF 14A filed January 9, 2007).
†10.7	Amendment No. 1 to Atwood Oceanics, Inc. 2007 Long-Term Incentive Plan (Incorporated by reference to Appendix B to our revised definitive proxy statement on Form DEF14A filed January 15, 2008).
†10.8	Form of Stock Option Agreement – 2007 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.1.1 of our Form 10-Q for the quarter ended March 31, 2007).

†10.9	Form of Restricted Stock Award Agreement – 2007 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.1.2 of our Form 10-Q for the quarter ended March 31, 2007).
†10.10	Form of Non-Employee Director Restricted Stock Award Agreement – 2007 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.1.15 of our Form 10-K for the year ended September 30, 2009).
†10.11	Atwood Oceanics, Inc. Amended and Restated 2007 Long-Term Incentive Plan (Incorporated herein by reference to our definitive proxy statement on Form DEF14A filed January 14, 2011).
†10.12	First Amendment to Atwood Oceanics, Inc. Amended and Restated 2007 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.3 to our Form 10-Q for the quarter ended December 31, 2011).
†10.13	Form of Notice of Restricted Stock Grant - 2007 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.4 to our Form 10-Q for the quarter ended December 31, 2011).
†10.14	Form of Notice of Non-employee Director Restricted Stock Grant - 2007 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.5 to our Form 10-Q for the quarter ended December 31, 2011).
†10.15	Form of Notice of Option Grant - 2007 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.6 to our Form 10-Q for the quarter ended December 31, 2011).
†10.16	Form of Notice of Performance Unit Grant - 2007 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.7 to our Form 10-Q for the quarter ended December 31, 2011).
†10.17	Atwood Oceanics, Inc. Restricted Stock Agreement with Robert J. Saltiel dated December 15, 2009 (Incorporated herein by reference to Exhibit 10.2 to our Form 10-Q for the quarter ended March 31, 2012).
†10.18	Atwood Oceanics, Inc. Amended and Restated Restricted Stock Agreement with Robert J. Saltiel dated December 21, 2010 (Incorporated herein by reference to Exhibit 10.3 to our Form 10-Q for the quarter ended March 31, 2012).
†10.19	Atwood Oceanics, Inc. Clarifying Amendment to Restricted Stock Award with Robert J. Saltiel dated April 20, 2012 (Incorporated herein by reference to Exhibit 10.4 to our Form 10-Q for the quarter ended March 31, 2012).
†10.20	Atwood Oceanics, Inc. Restricted Stock Agreement with Mark Mey dated August 11, 2010 (Incorporated herein by reference to Exhibit 10.5 to our Form 10-Q for the quarter ended March 31, 2012).
†10.21	Atwood Oceanics, Inc. Amended and Restated Restricted Stock Agreement with Mark Mey dated December 21, 2010 (Incorporated herein by reference to Exhibit 10.6 to our Form 10-Q for the quarter ended March 31, 2012).
†10.22	Atwood Oceanics, Inc. Clarifying Amendment to Restricted Stock Award with Mark Mey dated April 20, 2012 (Incorporated herein by reference to Exhibit 10.7 to our Form 10-Q for the quarter ended March 31, 2012).

†10.23	Form of Executive Change of Control Agreement (Incorporated herein by reference to Exhibit 10.1 to our Form 8-K filed May 30, 2012).
†10.24	Form of Retirement and Separation Agreement between the Company and Glen Kelley (Incorporated herein by reference to Exhibit 10.1 to our Form 8-K filed September 28, 2012).
†10.25	Form of Indemnification Agreement for Directors and Executive Officers (Incorporated herein by reference to Exhibit 10.1 to our Form 10-Q for the quarter ended March 31, 2012).
†10.26	Atwood Oceanics, Inc. Restated Executive Life Insurance Plan dated as of March 19, 1999 (Incorporated herein by reference to Exhibit 10.22 to our Form 10-K for the year ended September 30, 2011).
†10.27	First Amendment, dated as of May 24, 2012, to the Atwood Oceanics, Inc. Salary Continuation Plan (formerly known as the Restated Executive Life Insurance Plan)(Incorporated herein by reference to Exhibit 10.2 to our Form 8-K filed May 30, 2012).
†10.28	Form of Salary Continuation Agreement (Incorporated herein by reference to Exhibit 10.3 to our Form 8-K filed May 30, 2012).
†10.29	Atwood Oceanics, Inc. Benefits Equalization Plan (Incorporated herein by reference to Exhibit 10.23 to our Form 10-K for the year ended September 30, 2011).
†10.30	First Amendment to Atwood Oceanics Benefit Equalization Plan dated December 14, 2005 (Incorporate herein by reference to Exhibit 10.24 to our Form 10-K for the year ended September 30, 2011).

†10.31	Second Amendment to Atwood Oceanics Benefit Equalization Plan dated August 20, 2008 (Incorporated herein by reference to Exhibit 10.25 to our Form 10-K for the year ended September 30, 2011).
†10.32	Third Amendment to Atwood Oceanics Benefit Equalization Plan dated December 4, 2008 (Incorporate herein by reference to Exhibit 10.26 to our Form 10-K for the year ended December 31, 2011).
†10.33	Fourth Amendment to Atwood Oceanics Benefit Equalization Plan dated December 18, 2008 (Incorporated herein by reference to Exhibit 10.27 to our Form 10-K for the year ended December 31, 2011).
10.34	Credit Agreement dated May 6, 2011 among the Company, Atwood Offshore Worldwide Limited, Various Lenders and Nordea Bank Finland Plc, New York Branch (Incorporated herein by reference to Exhibit 10.1 of our Form 8-K filed May 9, 2011).
10.35	First Amendment to Credit Agreement, dated November 23, 2011, among Atwood Oceanics, Inc., Atwood Offshore Worldwide Limited, various lenders and Nordea Bank Finland Plc, New York Branch (Incorporated herein by reference to Exhibit 10.1 to our Form 8-K filed January 18, 2012).
10.36	Second Amendment to Credit Agreement, dated January 18, 2012, among Atwood Oceanics, Inc., Atwood Offshore Worldwide Limited, various lenders and Nordea Bank Finland Plc, New York Branch (Incorporated herein by reference to Exhibit 10.2 to our Form 10-Q for the quarter ended December 31, 2011).
10.37	Third Amendment to Credit Agreement, dated August 24, 2012, among Atwood Oceanics, Inc., Atwood Offshore Worldwide Limited, various lenders and Nordea Bank Finland Plc, New York Branch (Incorporated herein by reference to Exhibit 10.1 to our Form 8-K filed August 24, 2012).
10.38	Construction Contract for Second Rig between Atwood Oceanics Pacific Limited and PPL Shipyard Pte. Ltd. dated October 1, 2010 (Incorporated herein by reference to Exhibit 10.9 to our Form 10-K for the year ended September 30, 2010).
10.39	Construction Contract for Third Rig between Atwood Oceanics Pacific Limited and PPL Shipyard Pte. Ltd. dated January 14, 2011 (Incorporated herein by reference to Exhibit 10.1 to our Form 10-Q for the quarter ended March 30, 2010).
10.4	Contract for Construction and Sale of Drillship by and between Atwood Oceanics Pacific Limited and Daewoo Shipbuilding & Marine Engineering Co., Ltd., dated January 28, 2011 (Incorporated herein by reference to Exhibit 10.2 to our Form 10-Q for the quarter ended March 30, 2011).
10.41	Contract for Construction and Sale of Drillship by and between Alpha Eagle Company and Daewoo Shipbuilding & Marine Engineering Co., Ltd., dated October 15, 2011 (Incorporated herein by reference to Exhibit 10.34 to our Form 10-K for the year ended September 30, 2011).
*10.42	Contract for Construction and Sale of Drillship by and between Alpha Admiral Company and Daewoo Shipbuilding & Marine Engineering Co. Ltd., dated September 27, 2012.
*21.1	List of Subsidiaries.

*23	Consent of Independent Registered Public Accounting Firm.
*31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101	Interactive data files.
*	Filed herewith
†	Management contract or compensatory plan or arrangement

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ATWOOD OCEANICS, INC.

/s/ ROBERT J. SALTIEL
ROBERT J. SALTIEL
President and Chief Executive Officer

DATE: November 19, 2012

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

/S/ MARK L. MEY
MARK L. MEY
Senior Vice President, Chief Financial Officer
(Principal Financial and Accounting Officer)

Date: November 19, 2012

/S/ ROBERT J. SALTIEL
ROBERT J. SALTIEL
President and Chief Executive Officer;
Director
(Principal Executive Officer)

Date: November 19, 2012

/S/ PHIL D. WEDEMEYER
PHIL D. WEDEMEYER
Director

Date: November 19, 2012

/S/ GEORGE S. DOTSON
GEORGE S. DOTSON
Director

Date: November 19, 2012

/S/ HANS HELMERICH
HANS HELMERICH
Director

Date: November 19, 2012

/S/ DEBORAH A. BECK
DEBORAH A. BECK
Director

Date: November 19, 2012

/S/ JAMES R. MONTAGUE
JAMES R. MONTAGUE
Director

Date: November 19, 2012

/s/ JACK E. GOLDEN
JACK E. GOLDEN
Director

Date: November 19, 2012