HERCULES OFFSHORE, INC.
Form 10-K
March 02, 2010

Table of Contents

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

Form 10-K

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

For the fiscal year ended December 31, 2009
Commission file number: 0-51582

Hercules Offshore, Inc.
(Exact name of registrant as specified in its charter)

Delaware *(State or other jurisdiction of incorporation or organization)*	**56-2542838** *(I.R.S. Employer Identification No.)*
9 Greenway Plaza, Suite 2200 **Houston, Texas** *(Address of principal executive offices)*	**77046** *(Zip Code)*

Registrant s telephone number, including area code:
(713) 350-5100

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

Title of Each Class	Name of Exchange on Which Registered
Common Stock, $0.01 par value per share	NASDAQ Global Select Market
Rights to Purchase Preferred Stock	NASDAQ Global Select Market

Securities registered pursuant to Section 12(g) of the Act:
None

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 of the Act. Yes o No þ

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

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

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

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

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

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

The aggregate market value of the registrant s common stock held by non-affiliates as of June 30, 2009, based on the closing price on the NASDAQ Global Select Market on such date, was approximately $365 million. (As of such date, the registrant s directors and executive officers and LR Hercules Holdings, LP and its affiliates were considered affiliates of the registrant for this purpose.)

As of February 24, 2010, there were 114,723,684 shares of the registrant s common stock, par value $0.01 per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant s definitive proxy statement for the Annual Meeting of Stockholders to be held on May 11, 2010 are incorporated by reference into Part III of this report.

TABLE OF CONTENTS

Table of Contents

PART I

Item 1. *Business*

In this Annual Report on Form 10-K, we refer to Hercules Offshore, Inc. and its subsidiaries as we, the Company or Hercules Offshore, unless the context clearly indicates otherwise. Hercules Offshore, Inc. is a Delaware corporation formed in July 2004, with its principal executive offices located at 9 Greenway Plaza, Suite 2200, Houston, Texas 77046. Hercules Offshore s telephone number at such address is (713) 350-5100 and our Internet address is www.herculesoffshore.com.

Overview

Hercules Offshore, Inc. is a leading provider of shallow-water drilling and marine services to the oil and natural gas exploration and production industry globally. We provide these services to national oil and gas companies, major integrated energy companies and independent oil and natural gas operators. As of February 24, 2010, we owned a fleet of 30 jackup rigs, 17 barge rigs, three submersible rigs, one platform rig, a fleet of marine support vessels and 60 liftboat vessels. In addition, we operate five liftboat vessels owned by a third party. We own four retired jackup rigs and eight retired inland barges, all located in the U.S. Gulf of Mexico, which are currently not expected to re-enter active service. We have operations in nine countries on three continents. Our diverse fleet is capable of providing services such as oil and gas exploration and development drilling, well service, platform inspection maintenance and decommissioning operations.

In January 2009, we reclassified four of our cold-stacked jackup rigs located in the U.S. Gulf of Mexico and 10 of our cold-stacked inland barges as retired; subsequently in each of September and November 2009, we sold one retired inland barge for approximately $0.2 million and $0.4 million, respectively. Additionally, we recently entered into an agreement to sell our retired jackups *Hercules 191* and *Hercules 255* for $5.0 million each and in February 2010, we entered into an agreement to sell six of our retired barges for $3.0 million.

We report our business activities in six business segments which as of February 24, 2010, included the following:

Domestic Offshore includes 22 jackup rigs and three submersible rigs in the U.S. Gulf of Mexico that can drill in maximum water depths ranging from 85 to 350 feet. Eleven of the jackup rigs are either working on short-term contracts or available for contracts, ten are cold-stacked and one is mobilizing to the U.S. Gulf of Mexico from Mexico. All three submersibles are cold-stacked.

International Offshore includes 8 jackup rigs and one platform rig outside of the U.S. Gulf of Mexico. We have two jackup rigs working offshore in each of India and Saudi Arabia. We have one jackup rig contracted offshore in Malaysia and one platform rig under contract in Mexico. In addition, we have one jackup rig warm-stacked in each of Bahrain and Gabon and one jackup rig contracted to a customer in Angola, however, the rig is currently on stand-by in Gabon. In August 2009, we closed the sale of the *Hercules 110,* which was cold-stacked in Trinidad.

Inland includes a fleet of 6 conventional and 11 posted barge rigs that operate inland in marshes, rivers, lakes and shallow bay or coastal waterways along the U.S. Gulf Coast. Three of our inland barges are either operating on short-term contracts or available and 14 are cold-stacked.

Domestic Liftboats includes 41 liftboats in the U.S. Gulf of Mexico. Thirty-eight are operating and three are cold-stacked.

International Liftboats includes 24 liftboats. Twenty-two are operating or available for contract offshore West Africa, including five liftboats owned by a third party, and two are operating or available for contract in the Middle East region.

Delta Towing our Delta Towing business operates a fleet of 29 inland tugs, 12 offshore tugs, 34 crew boats, 46 deck barges, 16 shale barges and five spud barges along and in the U.S. Gulf of Mexico and along the Southeastern coast and from time to time in Mexico. Of these vessels, 21 crew boats, 16 inland tugs, five offshore tugs, one deck barge and one spud barge are cold-stacked, and the remaining are working or available for contracts.

In December 2009, we entered into an agreement with First Energy Bank B.S.C. (MENAdrill) whereby we would market, manage and operate two Friede & Goldman Super M2 design new-build jackup drilling rigs each with a maximum water depth of 300 feet. The rigs are currently under construction and are scheduled to be delivered in the fourth quarter of 2010. We are actively marketing the rigs on an exclusive and worldwide basis.

In January 2010, we entered into an agreement with SKDP 1 Ltd., an affiliate of Skeie Drilling & Production ASA, to market, manage and operate an ultra high specification KFESL Class N new-build jackup drilling rig with a maximum water depth of 400 feet. The rig is currently under construction and is scheduled to be delivered in either the third or fourth quarter of 2010, depending upon the exercise of certain options available to the owner. The agreement is limited to a specified opportunity in the Middle East.

We had previously entered into similar agreements with Mosvold Middle East Jackup I Ltd. and Mosvold Middle East Jackup II Ltd. to market, manage and operate two Friede & Goldman Super M2 design new-build jackup rigs. We later terminated these agreements by mutual agreement due to uncertainties in the timing of the delivery of the rigs and disputes between the owner and the builder of the rigs.

Our jackup rigs, submersible rigs and barge rigs are used primarily for exploration and development drilling in shallow waters. Under most of our contracts, we are paid a fixed daily rental rate called a dayrate, and we are required to pay all costs associated with our own crews as well as the upkeep and insurance of the rig and equipment. Dayrate drilling contracts typically provide for higher rates while the unit is operating and lower rates or a lump sum payment for periods of mobilization or when operations are interrupted or restricted by equipment breakdowns, adverse weather conditions or other factors.

Our liftboats are self-propelled, self-elevating vessels that support a broad range of offshore support services, including platform maintenance, platform construction, well intervention and decommissioning services throughout the life of an oil or natural gas well. A liftboat contract generally is based on a flat dayrate for the vessel and crew. Our liftboat dayrates are determined by prevailing market rates, vessel availability and historical rates paid by the specific customer. Under most of our liftboat contracts, we receive a variable rate for reimbursement of costs such as catering, fuel, oil, rental equipment, crane overtime and other items. Liftboat contracts generally are for shorter terms than are drilling contracts, although international liftboat contracts may have terms of greater than one year.

Our Fleet

Jackup Drilling Rigs

Jackup rigs are mobile, self-elevating drilling platforms equipped with legs that can be lowered to the ocean floor until a foundation is established to support the drilling platform. Once a foundation is established, the drilling platform is jacked further up the legs so that the platform is above the highest expected waves. The rig hull includes the drilling rig, jackup system, crew quarters, loading and unloading facilities, storage areas for bulk and liquid materials, helicopter landing deck and other related equipment.

Jackup rig legs may operate independently or have a lower hull referred to as a mat attached to the lower portion of the legs in order to provide a more stable foundation in soft bottom areas, similar to those encountered in certain of the shallow-water areas of the U.S. Gulf of Mexico or U.S. GOM . Mat-supported rigs generally are able to more quickly position themselves on the worksite and more easily move on and off location than independent leg rigs. Twenty-one of our jackup rigs are mat-supported and nine are independent leg rigs.

Our rigs are used primarily for exploration and development drilling in shallow waters. Twenty-three of our rigs have a cantilever design that permits the drilling platform to be extended out from the hull to perform drilling or workover operations over some types of pre-existing platforms or structures. Seven rigs have a slot-type design, which requires drilling operations to take place through a slot in the hull. Slot-type rigs are

Table of Contents

usually used for exploratory drilling rather than development drilling, in that their configuration makes them difficult to position over existing platforms or structures. Historically, jackup rigs with a cantilever design have maintained higher levels of utilization than rigs with a slot-type design.

As of February 24, 2010, 15 of our jackup rigs were operating under contracts ranging in duration from well-to-well to three years, at an average contract dayrate of approximately $63,800, excluding the dayrate associated with our Angola contract. In the following table, ILS means an independent leg slot-type jackup rig, MC means a mat-supported cantilevered jackup rig, ILC means an independent leg cantilevered jackup rig and MS means a mat-supported slot-type jackup rig.

The following table contains information regarding our jackup rig fleet as of February 24, 2010.

Rig Name	Type	Year Built/ Upgraded(c)	Maximum/ Minimum Water Depth Rating (Feet)	Rated Drilling Depth(a) (Feet)	Location	Status(b)
Hercules 85	ILS	1982	85/9	20,000	U.S. GOM	Cold Stacked
Hercules 101	MC	1980	100/20	20,000	U.S. GOM	Cold Stacked
Hercules 120	MC	1958	120/22	18,000	U.S. GOM	Contracted
Hercules 150	ILC	1979	150/10	20,000	U.S. GOM	Contracted
Hercules 152	MC	1980	150/22	20,000	U.S. GOM	Cold Stacked
Hercules 153	MC	1980/2007	150/22	25,000	U.S. GOM	Cold Stacked
Hercules 156	ILC	1983	150/14	20,000	Gabon	Warm Stacked
Hercules 170	ILC	1981/2006	170/16	16,000	Bahrain	Warm Stacked
Hercules 173	MC	1971	173/22	15,000	U.S. GOM	Contracted
Hercules 185(f)	ILC	1982/2009	150/20	20,000	Gabon	Contracted/Stand-by
Hercules 200	MC	1979	200/23	20,000	U.S. GOM	Contracted
Hercules 201	MC	1981	200/23	20,000	U.S. GOM	Contracted
Hercules 202	MC	1981	200/23	20,000	U.S. GOM	Contracted
Hercules 203	MC	1982	200/23	20,000	U.S. GOM	Cold Stacked
Hercules 204	MC	1981	200/23	20,000	U.S. GOM	Contracted
Hercules 205	MC	1979/2003	200/23	20,000	En route to U.S. GOM	En route
Hercules 206	MC	1980/2003	200/23	20,000	U.S. GOM	Cold Stacked
Hercules 207	MC	1981	200/23	20,000	U.S. GOM	Cold Stacked
Hercules 208(d)	MC	1980/2008	200/22	20,000	Malaysia	Contracted
Hercules 211	MC	1980	200/23	18,000(e)	U.S. GOM	Cold Stacked
Hercules 250	MS	1974	250/24	20,000	U.S. GOM	Cold Stacked
Hercules 251	MS	1978	250/24	20,000	U.S. GOM	Ready Stacked
Hercules 252	MS	1978	250/24	20,000	U.S. GOM	Cold Stacked
Hercules 253	MS	1982	250/24	20,000	U.S. GOM	Contracted
Hercules 257	MS	1979	250/24	20,000	U.S. GOM	Contracted
Hercules 258	MS	1979/2008	250/24	20,000	India	Contracted
Hercules 260	ILC	1979/2008	250/12	20,000	India	Contracted
Hercules 261	ILC	1979/2008	250/12	20,000	Saudi Arabia	Contracted
Hercules 262	ILC	1982/2008	250/12	20,000	Saudi Arabia	Contracted

Hercules 350	ILC	1982	350/16	25,000	U.S. GOM	Contracted

(a) Rated drilling depth means drilling depth stated by the manufacturer of the rig. Depending on deck space and other factors, a rig may not have the actual capacity to drill at the rated drilling depth.

(b) Rigs designated as Contracted are under contract while rigs described as Ready Stacked are not under contract but generally are ready for service. Rigs described as Warm Stacked may have a reduced number of crew, but only require a full crew to be ready for service. Rigs described as Cold Stacked are not actively marketed, normally require the hiring of an entire crew and require a maintenance review and refurbishment before they can function as a drilling rig.

Table of Contents

(c) Dates shown are the original date the rig was built and the date of the most recent upgrade and/or major refurbishment, if any.

(d) This rig is currently unable to operate in the U.S. Gulf of Mexico due to regulatory restrictions.

(e) Rated workover depth. *Hercules 211* is currently configured for workover activity, which includes maintenance and repair or modification of wells that have already been drilled and completed to enhance or resume the well s production.

(f) *Hercules 185* is currently contracted to a customer in Angola, however, the rig is currently on stand-by in Gabon. Currently it does not meet our revenue recognition criteria due to uncertainty surrounding collectability.

Other Drilling Rigs

A submersible rig is a mobile drilling platform that is towed to the well site where it is submerged by flooding its lower hull tanks until it rests on the sea floor, with the upper hull above the water surface. After completion of the drilling operation, the rig is refloated by pumping the water out of the lower hull, so that it can be towed to another location. Submersible rigs typically operate in water depths of 14 to 85 feet. Our three submersible rigs are upgradeable for deep gas drilling.

A platform drilling rig is placed on a production platform and is similar to a modular land rig. The production platform s crane is capable of lifting the modularized rig crane that subsequently sets the rig modules. The assembled rig has all the drilling, housing and support facilities necessary for drilling multiple production wells. Most platform drilling rig contracts are for multiple wells and extended periods of time on the same platform. Once work has been completed on a particular platform, the rig can be redeployed to another platform for further work. We have one platform drilling rig.

In the following table, Sub means a submersible rig and Plat means a platform drilling rig. The following table contains information regarding our other drilling rig fleet as of February 24, 2010.

Rig Name	Type	Year Built/ Upgraded(c)	Maximum/ Minimum Water Depth Rating (Feet)	Rated Drilling Depth(a) (Feet)	Location	Status(b)
Hercules 75	Sub	1983	85/14	25,000	U.S. GOM	Cold Stacked
Hercules 77	Sub	1982/2007	85/14	30,000	U.S. GOM	Cold Stacked
Hercules 78	Sub	1985/2007	85/14	30,000	U.S. GOM	Cold Stacked
Platform 3	Plat	1993	N/A	25,000	Mexico	Contracted

(a) Rated drilling depth means drilling depth stated by the manufacturer of the rig. Depending on deck space and other factors, a rig may not have the actual capacity to drill at the rated drilling depth.

(b)

Rigs described as Cold Stacked are not actively marketed, normally require the hiring of an entire crew and require a maintenance review and refurbishment before they can function as a drilling rig while rigs described as Contracted are under contract.

(c) Dates shown are the original date the rig was built and the date of the most recent upgrade and/or major refurbishment, if any.

Barge Drilling Rigs

Barge drilling rigs are mobile drilling platforms that are submersible and are built to work in seven to 20 feet of water. They are towed by tugboats to the drill site with the derrick lying down. The lower hull is then submerged by flooding compartments until it rests on the river or sea floor. The derrick is then raised and drilling operations are conducted with the barge resting on the bottom. Our barge drilling fleet consists of 17 conventional and posted barge rigs. A posted barge is identical to a conventional barge except that the hull and superstructure are separated by 10 to 14 foot columns, which increases the water depth capabilities of the rig. Several of our barge drilling rigs are upgradeable for deep gas drilling.

The following table contains information regarding our barge drilling rig fleet as of February 24, 2010.

Rig Name	Type	Year Built/ Upgraded(c)	Horsepower Rating	Rated Drilling Depth(a) (Feet)	Location	Status(b)
1	Conv.	1980	2,000	20,000	U.S. GOM	Cold Stacked
9	Posted	1981	2,000	25,000	U.S. GOM	Cold Stacked
11	Conv.	1982	3,000	30,000	U.S. GOM	Cold Stacked
15	Conv.	1981	2,000	25,000	U.S. GOM	Cold Stacked
17	Posted	1981	3,000	30,000	U.S. GOM	Contracted
19	Conv.	1974	1,000	14,000	U.S. GOM	Cold Stacked
27	Posted	1979/2008	3,000	30,000	U.S. GOM	Cold Stacked
28	Conv.	1980	3,000	30,000	U.S. GOM	Cold Stacked
29	Conv.	1981	3,000	30,000	U.S. GOM	Cold Stacked
41	Posted	1981	3,000	30,000	U.S. GOM	Contracted
46	Posted	1979	3,000	30,000	U.S. GOM	Cold Stacked
48	Posted	1982	3,000	30,000	U.S. GOM	Cold Stacked
49	Posted	1980	3,000	30,000	U.S. GOM	Contracted
52	Posted	1981	2,000	25,000	U.S. GOM	Cold Stacked
55	Posted	1981	3,000	30,000	U.S. GOM	Cold Stacked
57	Posted	1975	2,000	25,000	U.S. GOM	Cold Stacked
64	Posted	1979	3,000	30,000	U.S. GOM	Cold Stacked

(a) Rated drilling depth means drilling depth stated by the manufacturer of the rig. Depending on deck space and other factors, a rig may not have the actual capacity to drill at the rated drilling depth.

(b) Rigs designated as Contracted are under contract while rigs described as Cold Stacked are not actively marketed, normally require the hiring of an entire crew and require a maintenance review and refurbishment before they can function as a drilling rig.

(c) Dates shown are the original date the rig was built and the date of the most recent upgrade and/or major refurbishment, if any.

Liftboats

Our liftboats are self-propelled, self-elevating vessels with a large open deck space, which provides a versatile, mobile and stable platform to support a broad range of offshore maintenance and construction services throughout the life of an oil or natural gas well. Once a liftboat is in position, typically adjacent to an offshore production platform or well, third-party service providers perform:

production platform construction, inspection, maintenance and removal;

well intervention and workover;

well plug and abandonment; and

pipeline installation and maintenance.

Unlike larger and more costly alternatives, such as jackup rigs or construction barges, our liftboats are self-propelled and can quickly reposition at a worksite or move to another location without third-party assistance. Our liftboats are ideal working platforms to support platform and pipeline inspection and maintenance tasks because of their ability to maneuver efficiently and support multiple activities at different working heights. Diving operations may also be performed from our liftboats in connection with underwater inspections and repair. In addition, our liftboats provide an effective platform from which to perform well-servicing activities such as mechanical wireline, electrical wireline and coiled tubing operations. Technological advances, such as coiled tubing, allow more well-servicing procedures to be conducted from liftboats. Moreover, during both platform construction and removal, smaller platform components can be installed and

Table of Contents

removed more efficiently and at a lower cost using a liftboat crane and liftboat-based personnel than with a specialized construction barge or jackup rig.

The length of the legs is the principal measure of capability for a liftboat, as it determines the maximum water depth in which the liftboat can operate. The U.S. Coast Guard restricts the operation of liftboats to water depths less than 180 feet, so boats with longer leg lengths are useful primarily on taller platforms. Our liftboats in the U.S. Gulf of Mexico range in leg lengths up to 229 feet, which allows us to service approximately 83% of the approximately 3,700 existing production platforms in the U.S. Gulf of Mexico. Liftboats are typically moved to a port during severe weather to avoid the winds and waves they would be exposed to in open water.

As of February 24, 2010, we owned 41 liftboats operating in the U.S. Gulf of Mexico, 17 liftboats operating in West Africa, and two liftboats operating in the Middle East. In addition, we operated five liftboats owned by a third party in West Africa. The following table contains information regarding the liftboats we operate as of February 24, 2010.

Liftboat Name(1)	Year Built/ Upgraded(5)	Leg Length (Feet)	Deck Area (Square feet)	Maximum Deck Load (Pounds)	Location	Gross Tonnage
Whale Shark(4)	2005 /2009	260	8,170	729,000	Saudi Arabia	1,142
Tiger Shark(3)	2001	230	5,300	1,000,000	Nigeria	469
Kingfish(3)	1996	229	5,000	500,000	U.S. GOM	188
Man-O-War(3)	1996	229	5,000	500,000	U.S. GOM	188
Wahoo(3)	1981	215	4,525	500,000	U.S. GOM	491
Blue Shark(4)	1981	215	3,800	400,000	Nigeria	1,182
Amberjack(4)	1981	205	3,800	500,000	Saudi Arabia	417
Bullshark(3)	1998	200	7,000	1,000,000	U.S. GOM	859
Creole Fish(3)	2001	200	5,000	798,000	Nigeria	192
Cutlassfish(3)	2006	200	5,000	798,000	Nigeria	183
Black Jack(4)	1997/2008	200	4,000	480,000	Nigeria	777
Swordfish(3)	2000	190	4,000	700,000	U.S. GOM	189
Mako(3)	2003	175	5,074	654,000	Nigeria	168
Leatherjack(3)	1998	175	3,215	575,850	U.S. GOM	168
Oilfish(4)	1996	170	3,200	590,000	Nigeria	495
Manta Ray(3)	1981	150	2,400	200,000	U.S. GOM	194
Seabass(3)	1983	150	2,600	200,000	U.S. GOM	186
F.J. Leleux(2)	1981	150	2,600	200,000	Nigeria	407
Black Marlin(4)	1984	150	2,600	200,000	Nigeria	407
Hammerhead(3)	1980	145	1,648	150,000	U.S. GOM	178
Pilotfish(4)	1990	145	2,400	175,000	Nigeria	292
Rudderfish(4)	1991	145	3,000	100,000	Nigeria	309
Blue Runner(3)	1980	140	3,400	300,000	U.S. GOM	174
Starfish(3)	1978	140	2,266	150,000	U.S. GOM	99
Rainbow Runner(3)	1981	140	3,400	300,000	U.S. GOM	174
Pompano(3)	1981	130	1,864	100,000	U.S. GOM	196
Sandshark(3)	1982	130	1,940	150,000	U.S. GOM	196
Stingray(3)	1979	130	2,266	150,000	U.S. GOM	99

Albacore(3)	1985	130	1,764	150,000	U.S. GOM	171
Moray(3)	1980	130	1,824	130,000	U.S. GOM	178
Skipfish(3)	1985	130	1,116	110,000	U.S. GOM	91

Liftboat Name(1)	Year Built/ Upgraded(5)	Leg Length (Feet)	Deck Area (Square feet)	Maximum Deck Load (Pounds)	Location	Gross Tonnage
Sailfish(3)	1982	130	1,764	137,500	U.S. GOM	179
Mahi Mahi(3)	1980	130	1,710	142,000	U.S. GOM	99
Triggerfish(3)	2001	130	2,400	150,000	U.S. GOM	195
Scamp(4)	1984	130	2,400	150,000	Nigeria	195
Rockfish(3)	1981	125	1,728	150,000	U.S. GOM	192
Gar(3)	1978	120	2,100	150,000	U.S. GOM	98
Grouper(3)	1979	120	2,100	150,000	U.S. GOM	97
Sea Robin(3)	1984	120	1,507	110,000	U.S. GOM	98
Tilapia(3)	1976	120	1,280	110,000	U.S. GOM	97
Charlie Cobb(2)	1980	120	2,000	100,000	Nigeria	229
Durwood Speed(2)	1979	120	2,000	100,000	Nigeria	210
James Choat(2)	1980	120	2,000	100,000	Nigeria	210
Solefish(4)	1978	120	2,000	100,000	Nigeria	229
Tigerfish(4)	1980	120	2,000	100,000	Nigeria	210
Zoal Albrecht(2)	1982	120	2,000	100,000	Nigeria	213
Barracuda(3)	1979	105	1,648	110,000	U.S. GOM	93
Carp(3)	1978	105	1,648	110,000	U.S. GOM	98
Cobia(3)	1978	105	1,648	110,000	U.S. GOM	94
Dolphin(3)	1980	105	1,648	110,000	U.S. GOM	97
Herring(3)	1979	105	1,648	110,000	U.S. GOM	97
Marlin(3)	1979	105	1,648	110,000	U.S. GOM	97
Corina(3)	1974	105	953	100,000	U.S. GOM	98
Pike(3)	1980	105	1,360	130,000	U.S. GOM	92
Remora(3)	1976	105	1,179	100,000	U.S. GOM	94
Wolffish(3)	1977	105	1,044	100,000	U.S. GOM	99
Seabream(3)	1980	105	1,140	100,000	U.S. GOM	92
Sea Trout(3)	1978	105	1,500	100,000	U.S. GOM	97
Tarpon(3)	1979	105	1,648	110,000	U.S. GOM	97
Palometa(3)	1972	105	780	100,000	U.S. GOM	99
Jackfish(3)	1978	105	1,648	110,000	U.S. GOM	99
Bonefish(4)	1978	105	1,344	90,000	Nigeria	97
Croaker(4)	1976	105	1,344	72,000	Nigeria	82
Gemfish(4)	1978	105	2,000	100,000	Nigeria	223
Tapertail(4)	1979	105	1,392	110,000	Nigeria	100

(1) The *Palometa, Wolffish and Skipfish* are currently cold-stacked. All other liftboats are either available or operating.

(2) We operate these vessels; however, they are owned by a third party.

(3)

Pursuant to U.S. Coast Guard documentation, international regulatory bodies or non-U.S. Flag states may calculate gross tonnage differently than the U.S. Coast Guard.

(4) Pursuant to the registry documents issued by the Republic of Panama.

(5) Dates shown are the original date the vessel was built and the date of the most recent upgrade and/or major refurbishment, if any.

Competition

The shallow-water businesses in which we operate are highly competitive. Domestic drilling and liftboat contracts are traditionally short term in nature whereas international drilling and liftboat contracts are longer term in nature. The contracts are typically awarded on a competitive bid basis. Pricing is often the primary factor in determining which qualified contractor is awarded a job, although technical capability of service and equipment, unit availability, unit location, safety record and crew quality may also be considered. Certain of our competitors in the shallow-water business may have greater financial and other resources than we have, and may better enable them to withstand periods of low utilization, compete more effectively on the basis of price, build new rigs, acquire existing rigs, and make technological improvements to existing equipment or replace equipment that becomes obsolete. Competition for offshore rigs is usually on a global basis, as drilling rigs are highly mobile and may be moved, at a cost that is sometimes substantial, from one region to another in response to demand. However, our mat-supported jackup rigs are less capable than independent leg jackup rigs of managing variable sea floor conditions found in most areas outside the Gulf of Mexico. As a result, our ability to move our mat-supported jackup rigs to other regions in response to changes in market conditions is limited. Additionally, a number of our competitors have independent leg jackup rigs with generally higher specifications and capabilities than the independent leg rigs that we currently operate in the Gulf of Mexico. Particularly during market downturns when there is decreased rig demand, higher specification rigs may be more likely to obtain contracts than lower specification rigs.

Customers

Our customers primarily include major integrated energy companies, independent oil and natural gas operators and national oil companies. Each of the following customers accounted for more than 10% of our revenues in 2009:

	For the Years Ending December 31,		
	2009	2008	2007
Oil and Natural Gas Corporation Limited	16%	8%	%
Chevron Corporation	14	12	21
Saudi Aramco	13		
PEMEX Exploración y Producción (PEMEX)	10	8	3

No other customer accounted for more than 10% of our consolidated revenues in any period.

Contracts

Our contracts to provide services are individually negotiated and vary in their terms and provisions. Currently, all of our drilling contracts are on a dayrate basis. Dayrate drilling contracts typically provide for payment on a dayrate basis, with higher rates while the unit is operating and lower rates or a lump sum payment for periods of mobilization or when operations are interrupted or restricted by equipment breakdowns, adverse weather conditions or other factors.

A dayrate drilling contract generally extends over a period of time covering the drilling of a single well or group of wells or covering a stated term. These contracts typically can be terminated by the customer under various circumstances such as the loss or destruction of the drilling unit or the suspension of drilling operations for a specified period of time as a result of a breakdown of major equipment or due to events beyond the control of either party. In addition, customers in some instances have the right to terminate our contracts with little or no prior notice, and without penalty or early termination payments. The contract term in some instances may be extended by the customers exercising options for the drilling of additional wells or for an additional term, or by exercising a right of first refusal. To date, most of our contracts in the U.S. Gulf of Mexico have been on a short-term basis of less than six months. Our contracts in international locations have been longer-term, with contract terms of up to three years. For contracts over six months in term we may have the right to pass through certain cost escalations. Our customers may have the right to terminate, or may seek to renegotiate, existing contracts if we experience downtime or operational problems above a contractual limit, if the rig is a total loss, or in other specified circumstances. A customer is more likely to seek to cancel or renegotiate its contract during periods of depressed market conditions. We could be required to pay penalties if some of our contracts with our customers are canceled due to downtime or operational problems. Suspension of drilling contracts results in the reduction in or loss of dayrates for the period of the suspension.

A liftboat contract generally is based on a flat dayrate for the vessel and crew. Our liftboat dayrates are determined by prevailing market rates, vessel availability and historical rates paid by the specific customer. Under most of our liftboat contracts, we receive a variable rate for reimbursement of costs such as catering, fuel, oil, rental equipment, crane overtime and other items. Liftboat contracts generally are for shorter terms than are drilling contracts.

On larger contracts, particularly outside the United States, we may be required to arrange for the issuance of a variety of bank guarantees, performance bonds or letters of credit. The issuance of such guarantees may be a condition of the bidding process imposed by our customers for work outside the United States. The customer would have the right to call on the guarantee, bond or letter of credit in the event we default in the performance of the services. The guarantees, bonds and letters of credit would typically expire after we complete the services.

Contract Backlog

The following table reflects the amount of our contract backlog by year as of February 24, 2010, excluding the amount related to our Angola contract. We calculate our backlog, or future contracted revenue, as the contract dayrate multiplied by the number of days remaining on the contract, assuming full utilization. Backlog excludes revenues for mobilization, demobilization, contract preparation and customer reimbursables. The amount of actual revenues earned and the actual periods during which revenues are earned will be different than the backlog disclosed or expected due to various factors. Downtime due to various operational factors, including unscheduled repairs, maintenance, weather and other factors (some of which are beyond our control), may result in lower dayrates than the full contractual operating dayrate. In some of the contracts, our customer has the right to terminate the contract without penalty and in certain instances, with little or no notice.

		For the Years Ending December 31,				
	Total	2010	2011	2012	2013	Thereafter
			(In thousands)			
Domestic Offshore	$ 33,698	$ 33,698	$	$	$	$
International Offshore	346,978	215,511	131,467			
Inland	2,273	2,273				
International Liftboats	16,782	16,782				
Total	$ 399,731	$ 268,264	$ 131,467	$	$	$

Employees

As of December 31, 2009, we had approximately 2,200 employees. We require skilled personnel to operate and provide technical services and support for our rigs, barges and liftboats. As a result, we conduct extensive personnel training and safety programs.

Certain of our employees in West Africa are working under collective bargaining agreements. Additionally, efforts have been made from time to time to unionize portions of the offshore workforce in the U.S. Gulf of Mexico. We believe that our employee relations are good.

Insurance

We maintain insurance coverage that includes coverage for physical damage, third party liability, workers compensation and employers liability, general liability, vessel pollution and other coverages. Our insurance coverage includes self-insured retentions and deductibles that we must pay or absorb. Additionally, under certain policies, we are responsible for 15% of the losses above the applicable retention or deductible and as high as 30% of losses incurred as a result of a named windstorm in the Gulf of Mexico. This additional amount is often referred to as quota share. Management believes that adequate accruals have been made on known and expected exposures for the self-insured retentions, deductibles and for our quota share. However, our insurance is subject to exclusions and limitations and there is no assurance that such coverage will adequately protect us against liability from all potential consequences and damages.

Our primary marine package provides for hull and machinery coverage for our rigs and liftboats up to a scheduled value for each asset. The maximum coverage for these assets is $2.2 billion; however, coverage for U.S. Gulf of Mexico named windstorm damage is subject to an annual aggregate limit on liability of $100.0 million. The policies are subject to exclusions, limitations, deductibles, self-insured retention and other conditions. Deductibles for events that are not U.S. Gulf of Mexico named windstorm events are 12.5% of insured values per occurrence for drilling rigs, and $1.0 million per occurrence for liftboats, regardless of the insured value of the particular vessel. The deductibles for drilling rigs and liftboats in a U.S. Gulf of Mexico named windstorm event are the greater of $25.0 million or the operational deductible for each U.S. Gulf of Mexico named windstorm. We are self-insured for 15% above the deductibles for removal of wreck, sue and labor, collision, protection and indemnity general liability and hull and physical damage policies. The protection and indemnity coverage under the primary marine package has a $5.0 million limit per occurrence with excess liability coverage up to $200.0 million. The primary marine package also provides coverage for cargo and charterer s legal liability. Vessel pollution is covered under a Water Quality Insurance Syndicate policy with a $3 million deductible proving limits as required. In addition to the marine package, we have separate policies providing coverage for onshore general liability, employer s liability, auto liability and non-owned aircraft liability, with customary deductibles and coverage as well as a separate primary marine package for our Delta Towing business. Our policy related to all but our Delta Towing business, which we renew annually, expires in April 2010. Our policy related to our Delta Towing business, which we also renew annually, expires in August 2010.

Regulation

Our operations are affected in varying degrees by governmental laws and regulations. Our industry is dependent on demand for services from the oil and natural gas industry and, accordingly, is also affected by changing tax and other laws relating to the energy business generally. In the United States, we are also subject to the jurisdiction of the U.S. Coast Guard, the National Transportation Safety Board and the U.S. Customs and Border Protection Service, as well as private industry organizations such as the American Bureau of Shipping. The Coast Guard and the National Transportation Safety Board set safety standards and are authorized to investigate vessel accidents and recommend improved safety standards, and the U.S. Customs Service is authorized to inspect vessels at will. Coast Guard regulations also require annual inspections and periodic drydock inspections or special examinations of our vessels.

The shorelines and shallow water areas of the U.S. Gulf of Mexico are ecologically sensitive. Heightened environmental concerns in these areas have led to higher drilling costs and a more difficult and lengthy well permitting process and, in general, have adversely affected drilling decisions of oil and natural gas companies. In the United States, regulations applicable to our operations include regulations that require us to obtain and maintain specified permits or governmental approvals, control the discharge of materials into the environment, require removal and cleanup of materials that may harm the environment or otherwise relate to the protection of the environment. For example, as an operator of mobile offshore units in navigable U.S. waters and some offshore areas, we may be liable for damages and costs incurred in connection with oil spills or other unauthorized discharges of chemicals or wastes resulting from or related to those operations. 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 or more stringent requirements could have a material adverse effect on our financial condition and results of operations.

The U.S. Federal Water Pollution Control Act of 1972, commonly referred to as the Clean Water Act, prohibits the discharge of pollutants 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. Historically, the discharge of ballast water and other substances incidental to the normal operation of vessels visiting U.S. ports was exempted from the Clean Water Act permitting requirements. Challenges arising largely out of foreign invasive species contained in discharges of ballast water resulted in a 2006 court order that vacated, as of September 30, 2008, an exemption from Clean Water Act discharge permit requirements for discharges incidental to normal operation of a vessel. The district court later delayed the vacation until February 6, 2009. Pursuant to the court s ruling and recent legislation, the EPA adopted a Vessel General Permit that became effective on December 19, 2008. The regulated community was required to comply with the terms of the Vessel General Permit as of February 6, 2009. We have obtained the necessary Vessel General Permit for all of our vessels to which this regulation applies. In addition to this federal development, some states have begun regulating ballast water discharges. Violations of monitoring, reporting and permitting requirements can result in the imposition of civil and criminal penalties. We have incurred and will continue to incur certain costs associated with the requirements under the Vessel General Permit and other requirements that may be adopted. However, we believe that any financial impacts resulting from the imposition of the permitting exemption and the implementation of federal and possible state regulation of ballast water discharges will not be material.

The U.S. Oil Pollution Act of 1990 (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 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 also requires owners and operators of all vessels over 300 gross tons to establish and maintain with the U.S. Coast Guard evidence of financial responsibility sufficient to meet their potential liabilities under OPA. The 2006 amendments to OPA require evidence of financial responsibility for a vessel over 300 gross tons in the amount that is the greater of $950 per gross ton or $800,000. Under OPA, an owner or operator of a fleet of vessels is required only to demonstrate evidence of financial responsibility in an amount sufficient to cover the vessel in the fleet having the greatest maximum liability under OPA. Vessel owners and operators may evidence their financial responsibility by showing proof of insurance, surety bond, self-insurance or guarantee. We have obtained the necessary OPA financial assurance certifications for each of our vessels subject to such requirements.

The U.S. Outer Continental Shelf Lands Act authorizes regulations relating to safety and environmental protection applicable to lessees and permittees operating on the outer continental shelf. Included among these are regulations that require the preparation of spill contingency plans and establish air quality standards for certain pollutants, including particulate matter, volatile organic compounds, sulfur dioxide, carbon monoxide and nitrogen oxides. Specific design and operational standards may apply to outer continental shelf vessels, rigs, platforms, vehicles and structures. Violations of lease conditions or regulations related to the environment issued pursuant to the Outer Continental Shelf Lands Act can result in substantial civil and criminal penalties, as well as potential court injunctions curtailing operations and canceling leases. Such enforcement liabilities can result from either governmental or citizen prosecution.

The U.S. Comprehensive Environmental Response, Compensation, and Liability Act, also known as CERCLA or 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. These persons include the owner or operator of a facility where a release occurred, the owner or operator of a vessel from which there is a release, and companies that disposed or arranged for the 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 liability for the cost of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. Prior owners and operators are also subject to liability under CERCLA. 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.

In recent years, a variety of initiatives intended to enhance vessel security were adopted to address terrorism risks, including the U.S. Coast Guard regulations implementing the Maritime Transportation and Security Act of 2002. These regulations required, among other things, the development of vessel security plans and on-board installation of automatic information systems, or AIS, to enhance vessel-to-vessel and vessel-to-shore communications. We believe that our vessels are in substantial compliance with all vessel security regulations.

Some operations are conducted in the U.S. domestic trade, which is governed by the coastwise laws of the United States. The U.S. coastwise laws reserve marine transportation, including liftboat services, between points in the United States to vessels built in and documented under the laws of the United States and owned and manned by U.S. citizens. Generally, an entity is deemed a U.S. citizen for these purposes so long as:

- it is organized under the laws of the United States or a state;
- each of its president or other chief executive officer and the chairman of its board of directors is a U.S. citizen;
- no more than a minority of the number of its directors necessary to constitute a quorum for the transaction of business are non-U.S. citizens; and
- at least 75% of the interest and voting power in the corporation is held by U.S. citizens free of any trust, fiduciary arrangement or other agreement, arrangement or understanding whereby voting power may be exercised directly or indirectly by non-U.S. citizens.

Because we could lose our privilege of operating our liftboats in the U.S. coastwise trade if non-U.S. citizens were to own or control in excess of 25% of our outstanding interests, our certificate of incorporation restricts foreign ownership and control of our common stock to not more than 20% of our outstanding interests. One of our liftboats relies on an exemption from coastwise laws in order to operate in the U.S. Gulf of Mexico. If this liftboat were to lose this exemption, we would be unable to use it in the U.S. Gulf of Mexico and would be forced to seek opportunities for it in international locations.

The United States is one of approximately 165 member countries to the International Maritime Organization (IMO), a specialized agency of the United Nations that is responsible for developing measures to improve the safety and security of international shipping and to prevent marine pollution from ships. Among the various international conventions negotiated by the IMO is the International Convention for the Prevention of Pollution from Ships (MARPOL). MARPOL imposes environmental standards on the shipping industry relating to oil spills, management of garbage, the handling and disposal of noxious liquids, harmful substances in packaged forms, sewage and air emissions.

Annex VI to MARPOL sets limits on sulfur dioxide and nitrogen oxide emissions from ship exhausts and prohibits deliberate emissions of ozone depleting substances. Annex VI also imposes a global cap on the sulfur content of fuel oil and allows for specialized areas to be established internationally with more stringent controls on sulfur emissions. For vessels 400 gross tons and greater, platforms and drilling rigs, Annex VI imposes various survey and certification requirements. For this purpose, gross tonnage is based on the International Tonnage Certificate for the vessel, which may vary from the standard U.S. gross tonnage for the vessel reflected in our liftboat table above. The United States has not yet ratified Annex VI. Any vessels we operate internationally are, however, subject to the requirements of Annex VI in those countries that have implemented its provisions. We believe the rigs we currently offer for international projects are generally exempt from the more costly compliance requirements of Annex VI and the liftboats we currently offer for international projects are generally exempt from or otherwise substantially comply with those requirements. Accordingly, we do not anticipate incurring significant costs to comply with Annex VI in the near term. If the United States does elect to ratify Annex VI in the future, we could be required to incur potentially significant costs to bring certain of our vessels into compliance with these requirements.

Our non-U.S. operations are subject to other laws and regulations in countries in which we operate, including laws and regulations relating to the importation of and operation of rigs and liftboats, currency conversions and repatriation, oil and natural gas exploration and development, environmental protection, taxation of offshore earnings and earnings of expatriate personnel, the use of local employees and suppliers by foreign contractors and duties on the importation and exportation of rigs, liftboats 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 natural gas and other aspects of the oil and natural 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 natural 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.

Although significant capital expenditures may be required to comply with these governmental laws and regulations, such compliance has not materially adversely affected our earnings or competitive position. We believe that we are currently in compliance in all material respects with the environmental regulations to which we are subject.

Available Information

General information about us, including our corporate governance policies can be found on our Internet website at *www.herculesoffshore.com*. On our website we make available, free of charge, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file or furnish them to the SEC. These filings also are available at the SEC s Internet website at *www.sec.gov*. Information contained on our website is not part of this annual report.

Segment and Geographic Information

Information with respect to revenues, operating income and total assets attributable to our segments and revenues and long-lived assets by geographic areas of operations is presented in Note 17 of our Notes to Consolidated Financial Statements included in Item 8 of this annual report. Additional information about our segments, as well as information with respect to the impact of seasonal weather patterns on domestic operations, is presented in Management s Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this annual report.

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

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

Our business depends on the level of activity of oil and natural gas exploration, development and production in the U.S. Gulf of Mexico and internationally, and in particular, the level of exploration, development and production expenditures of our customers. Demand for our drilling services is adversely affected by declines associated with depressed oil and natural gas prices. Even the perceived risk of a decline in oil or natural gas prices often causes oil and gas companies to reduce spending on exploration, development and production. Reductions in capital expenditures of our customers reduce rig utilization and day rates. In particular, changes in the price of natural gas materially affect our operations because drilling in the shallow-water U.S. Gulf of Mexico is primarily focused on developing and producing natural gas reserves. However, higher prices do not necessarily translate into increased drilling activity since our clients expectations about future commodity prices typically drive demand for our services. Oil and natural gas prices are extremely volatile and have recently declined considerably. On July 2, 2008 natural gas prices were $13.31 per million British thermal unit, or MMBtu, at the Henry Hub. They subsequently declined sharply, reaching a low of $1.88 per MMBtu at the Henry Hub on September 4, 2009. As of February 24, 2010, the closing price of natural gas at the Henry Hub was $4.91 per MMBtu. The spot price for West Texas intermediate crude has recently ranged from a high of $145.29 per barrel as of July 3, 2008, to a low of $31.41 per barrel as of December 22, 2008, with a closing price of $79.75 per barrel as of February 24, 2010. Commodity prices are affected by numerous factors, including the following:

- the demand for oil and natural gas in the United States and elsewhere;
- the cost of exploring for, developing, producing and delivering oil and natural gas, and the relative cost of onshore production or importation of natural gas;
- political, economic and weather conditions in the United States and elsewhere;
- imports of liquefied natural gas;
- advances in exploration, development and production technology;
- the ability of the Organization of Petroleum Exporting Countries, commonly called OPEC, to set and maintain oil production levels and pricing;
- the level of production in non-OPEC countries;
- domestic and international tax policies and governmental regulations;
- the development and exploitation of alternative fuels, and the competitive, social and political position of natural gas as a source of energy compared with other energy sources;
- the policies of various governments regarding exploration and development of their oil and natural gas reserves;
- the worldwide military and political environment and uncertainty or instability resulting from an escalation or additional outbreak of armed hostilities or other crises in the Middle East, West Africa and other significant oil and natural gas producing regions; and
- acts of terrorism or piracy that affect oil and natural gas producing regions, especially in Nigeria, where armed conflict, civil unrest and acts of terrorism have recently increased.

As a result of the economic downturn, reduced demand for drilling and liftboat services has materially eroded dayrates and utilization rates for our units, adversely affecting our financial condition and results of operations. The economic downturn has led to a decline in energy consumption, which has materially and adversely affected our results of operations. Continued hostilities in the Middle East and West Africa and the occurrence or threat of terrorist attacks against the United States or other countries could contribute to the economic downturn in the economies of the United States and other countries where we operate. A sustained or deeper recession could further limit economic activity and thus result in an additional decrease in energy consumption, which in turn would cause our revenues and margins to further decline and limit our future growth prospects.

The offshore service industry is highly cyclical and is currently experiencing low demand and low dayrates. The volatility of the industry, coupled with our short-term contracts, has resulted and could continue to result in sharp declines in our profitability.

Historically, the offshore service industry has been highly cyclical, with periods of high demand and high dayrates often followed by periods of low demand and low dayrates. Periods of low demand or increasing supply, such as we are currently experiencing, intensify the competition in the industry and often result in rigs or liftboats being idle for long periods of time. In response to the recent economic downturn, we have stacked additional rigs and liftboats and entered into lower dayrate contracts. As a result of the cyclicality of our industry, we expect our results of operations to be volatile and to decrease during market declines such as we are currently experiencing.

Maintaining idle assets or the sale of assets below their then carrying value may cause us to experience losses and may result in impairment charges.

Prolonged periods of low utilization and dayrates, the cold stacking of idle assets or the sale of assets below their then carrying value may cause us to experience losses. These events may also result in the recognition of impairment charges on certain of our assets if future cash flow estimates, based upon information available to management at the time, indicate that their carrying value may not be recoverable or if we sell assets at below their then current carrying value.

Our industry is highly competitive, with intense price competition. Our inability to compete successfully may reduce our profitability.

Our industry is highly competitive. Our contracts are traditionally awarded on a competitive bid basis. Pricing is often the primary factor in determining which qualified contractor is awarded a job, although rig and liftboat availability, location and technical capability and each contractor s safety performance record and reputation for quality also can be key factors in the determination. Dayrates also depend on the supply of rigs and vessels. Generally, excess capacity puts downward pressure on dayrates, and we have recently experienced declines in utilization and dayrates. Excess capacity can occur when newly constructed rigs and vessels enter service, when rigs and vessels are mobilized between geographic areas and when non-marketed rigs and vessels are re-activated.

Several of our competitors also are incorporated in tax-haven countries outside the United States, which provides them with significant tax advantages that are not available to us as a U.S. company, which may materially impair our ability to compete with them for many projects that would be beneficial to our company.

We have a significant level of debt, and could incur additional debt in the future. Our debt could have significant consequences for our business and future prospects.

As of December 31, 2009, we had total outstanding debt of approximately $861.7 million. This debt represented approximately 47% of our total book capitalization. As of December 31, 2009, we had $165.0 million of available capacity under our revolving credit facility, after the commitment of $10.0 million for standby letters of credit. We may borrow under our revolving credit facility to fund working capital or other needs in the near term up to the remaining availability. Our debt and the limitations imposed on us by our existing or future debt agreements could have significant consequences for our business and future prospects, including the following:

- we may not be able to obtain necessary financing in the future for working capital, capital expenditures, acquisitions, debt service requirements or other purposes and we may be required under the terms of the amendment to our credit facility to use the proceeds of any financing we obtain to repay or prepay existing debt;
- we will be required to dedicate a substantial portion of our cash flow from operations to payments of principal and interest on our debt;
- we may be exposed to risks inherent in interest rate fluctuations because 56 percent of our borrowings are at variable rates of interest, which will result in higher interest expense to the extent that we do not hedge such risk in the event of increases in interest rates;
- we could be more vulnerable during downturns in our business and be less able to take advantage of significant business opportunities and to react to changes in our business and in market or industry conditions; and

we may have a competitive disadvantage relative to our competitors that have less debt.

Our ability to make payments on and to refinance our indebtedness, including the term loan issued in July 2007, the convertible notes issued by us in June 2008 and the senior secured notes issued by us in October 2009, and to fund planned capital expenditures will depend on our ability to generate cash in the future, which is subject to general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control. Our future cash flows may be insufficient to meet all of our debt obligations and other commitments, and any insufficiency could negatively impact our business. To the extent we are unable to repay our indebtedness as it becomes due or at maturity with cash on hand, we will need to refinance our debt, sell assets or repay the debt with the proceeds from equity offerings. Additional indebtedness or equity financing may not be available to us in the future for the refinancing or repayment of existing indebtedness, and we may not be able to complete asset sales in a timely manner sufficient to make such repayments.

If we are unable to comply with the restrictions and covenants in our credit agreement, there could be a default, which could result in an acceleration of repayment of funds that we have borrowed.

Our Credit Agreement (Credit Agreement) requires that we meet certain financial ratios and tests. Effective July 27, 2009, we entered into an amendment of our Credit Agreement (Credit Amendment) to provide additional flexibility in certain financial covenants. However, there can be no assurance that we will be able to comply with the modified financial covenants. Furthermore, the Credit Amendment also imposes additional and different covenants and restrictions, including the imposition of a requirement to maintain a minimum level of liquidity at all times. Our ability to comply with these financial covenants and restrictions can be affected by events beyond our control. Continued reduced activity levels in the oil and natural gas industry and continued construction of newbuild jackup rigs could adversely impact our ability to comply with such covenants in the future. Our failure to comply with such covenants would result in an event of default under the Credit Agreement. An event of default could prevent us from borrowing under our revolving credit facility, which could in turn have a material adverse effect on our available liquidity. In addition, an event of default could result in our having to immediately repay all amounts outstanding under the credit facility, the 3.375% Convertible Senior Notes due 2038 (3.375% Convertible Senior Notes), the 10.5% Senior Secured Notes due 2017 (10.5% Senior Secured Notes) and in foreclosure of liens on our assets. As of December 31, 2009, we were in compliance with all of our financial covenants under the Credit Agreement.

Our Credit Agreement imposes significant additional costs and operating and financial restrictions on us, which may prevent us from capitalizing on business opportunities and taking certain actions.

Our Credit Agreement imposes significant additional costs and operating and financial restrictions on us. These restrictions limit our ability to, among other things:

- make certain types of loans and investments;
- pay dividends, redeem or repurchase stock, prepay, redeem or repurchase other debt or make other restricted payments;
- incur or guarantee additional indebtedness;
- use proceeds from asset sales, new indebtedness or equity issuances for general corporate purposes or investment into our current business;
- invest in certain new joint ventures;
- create or incur liens;
- place restrictions on our subsidiaries ability to make dividends or other payments to us;
- sell our assets or consolidate or merge with or into other companies;

engage in transactions with affiliates; and

enter into new lines of business.

In addition, under our Credit Agreement, we are required to prepay our term loan with 100% of our excess cash flow for the fiscal year ending December 31, 2009 and, thereafter, 50% of our excess cash flow through the fiscal year ending December 31, 2012. Our term loan must also be prepaid using the proceeds from unsecured debt issuances (with the exception of refinancing), secured debt issuances and sales of assets in excess of $25 million annually, as well as 50% of proceeds from equity issuances (excluding those for

Table of Contents

permitted acquisitions or to meet the minimum liquidity requirements) unless we have achieved a specified leverage ratio. Our Credit Agreement also imposes significant financial and operating restrictions on us. These restrictions limit our ability to acquire assets, except in cases in which the consideration is equity (the net cash proceeds of an issuance thereof) unless we are in compliance with our financial covenants as they existed prior to the amendment of the Credit Agreement in July 2009. Our compliance with these provisions may materially adversely affect our ability to react to changes in market conditions, take advantage of business opportunities we believe to be desirable, obtain future financing, fund needed capital expenditures, finance our acquisitions, equipment purchases and development expenditures, or withstand the present or any future downturn in our business.

The continuing worldwide economic problems have materially reduced our revenue, profitability and cash flows.

The current worldwide economic problems have reduced the availability of liquidity and credit to fund business operations worldwide, and has adversely affected our customers, suppliers and lenders. The recent recession has caused a reduction in worldwide demand for energy and resulted in lower oil and natural gas prices. Demand for our services depends on oil and natural gas industry activity and capital expenditure levels that are directly affected by trends in oil and natural gas prices. Any prolonged reduction in oil and natural gas prices will further depress the current levels of exploration, development and production activity. Perceptions of longer-term lower oil and natural gas prices by oil and gas companies can similarly reduce or defer major expenditures. Lower levels of activity result in a corresponding decline in the demand for our services, which could have a material adverse effect on our revenue and profitability.

We may require additional capital in the future, which may not be available to us or may be at a cost which reduces our cash flow and profitability.

Our business is capital-intensive and, to the extent we do not generate sufficient cash from operations, we may need to raise additional funds through public or private debt (which would increase our interest costs) or equity financings to execute our business strategy, to fund capital expenditures or to meet our covenants under the Credit Agreement. Adequate sources of capital funding may not be available when needed or may not be available on acceptable terms and under the terms of our Credit Agreement, we may be required to use the proceeds of any capital that we raise to repay existing indebtedness. If we raise additional funds by issuing additional equity securities, existing stockholders may experience dilution. If funding is insufficient at any time in the future, we may be unable to fund maintenance of our vessels, take advantage of business opportunities or respond to competitive pressures, any of which could harm our business.

Asset sales are currently an important component of our business strategy for the purpose of reducing our debt. We may be unable to identify appropriate buyers with access to financing or to complete any sales on acceptable terms.

We are currently considering sales or other dispositions of certain of our assets, and any such disposition could be significant and could significantly affect the results of operations of one or more of our business segments. In the current economic recession, asset sales may occur on less favorable terms than terms that might be available at other times in the business cycle. At any given time, discussions with one or more potential buyers may be at different stages. However, any such discussions may or may not result in the consummation of an asset sale. We may not be able to identify buyers with access to financing or complete any sales on acceptable terms.

Our contracts are generally short term, and we will experience reduced profitability if our customers reduce activity levels or terminate or seek to renegotiate our drilling or liftboat contracts or if we experience downtime, operational difficulties, or safety-related issues.

Currently, all of our drilling contracts with major customers are dayrate contracts, where we charge a fixed charge per day regardless of the number of days needed to drill the well. Likewise, under our current liftboat contracts, we charge a fixed fee per day regardless of the success of the operations that are being conducted by our customer utilizing our liftboat. During depressed market conditions, a customer may no longer need a rig or liftboat that is currently under contract or may be able to obtain a comparable rig or liftboat at a lower daily rate. As a result, customers may seek to renegotiate the terms of their existing drilling contracts or avoid their obligations under those contracts. In addition, our customers may have the right to terminate, or may seek to renegotiate, existing contracts if we experience downtime, operational problems above the contractual limit or safety-related issues, if the rig or liftboat is a total loss, if the rig or liftboat is not delivered to the customer within the period specified in the contract or in other specified circumstances, which include events beyond the control of either party.

In the U.S. Gulf of Mexico, contracts are generally short term, and oil and natural gas companies tend to reduce activity levels quickly in response to downward changes in oil and natural gas prices. Due to the short-term nature of most of our contracts, a decline in market conditions can quickly affect our business if customers reduce their levels of operations.

Some of our contracts with our customers include terms allowing them to terminate the contracts without cause, with little or no prior notice and without penalty or early termination payments. In addition, we could be required to pay penalties if some of our contracts with our customers are terminated due to downtime, operational problems or failure to deliver. Some of our other contracts with customers may be cancelable at the option of the customer upon payment of a penalty, which may not fully compensate us for the loss of the contract. Early termination of a contract may result in a rig or liftboat being idle for an extended period of time. The likelihood that a customer may seek to terminate a contract is increased during periods of market weakness. If our customers cancel or require us to renegotiate some of our significant contracts, such as the contracts in our International Offshore segment, and we are unable to secure new contracts on substantially similar terms, or if contracts are suspended for an extended period of time, our revenues and profitability would be materially reduced.

An increase in supply of rigs or liftboats could adversely affect our financial condition and results of operations.

Reactivation of non-marketed rigs or liftboats, mobilization of rigs or liftboats back to the U.S. Gulf of Mexico or new construction of rigs or liftboats could result in excess supply in the region, and our dayrates and utilization could be reduced.

Construction of rigs could result in excess supply in international regions, which could reduce our ability to secure new contracts for our warm stacked rigs and could reduce our ability to renew, or extend or obtain new contracts for working rigs at the end of their contract term. The excess supply would also impact the dayrates on future contracts.

If market conditions improve, inactive rigs and liftboats that are not currently being marketed could be reactivated to meet an increase in demand. Improved market conditions in the U.S. Gulf of Mexico, particularly relative to other regions, could also lead to jackup rigs, other mobile offshore drilling units and liftboats being moved into the U.S. Gulf of Mexico. Improved market conditions in any region worldwide could lead to increased construction and upgrade programs by our competitors. Some of our competitors have already announced plans to upgrade existing equipment or build additional jackup rigs with higher specifications than our rigs. According to ODS-Petrodata, as of February 24, 2010, 60 jackup rigs were under construction or on order by industry participants, national oil companies and financial investors for delivery through 2012. Many of the rigs currently under construction have not been contracted for future work, which may intensify price competition as scheduled delivery dates occur. In addition, as of February 24, 2010, we believe there were also eight liftboats under construction or on order in the United States that may be used in the U.S. Gulf of Mexico. A significant increase in the supply of jackup rigs, other mobile offshore drilling units or liftboats could adversely affect both our utilization and dayrates.

Table of Contents

Our business involves numerous operating hazards and exposure to extreme weather and climate risks, and our insurance may not be adequate to cover our losses.

Our operations are subject to the usual hazards inherent in the drilling and operation of oil and natural gas wells, such as blowouts, reservoir damage, loss of production, loss of well control, punchthroughs, craterings, fires and pollution. The occurrence of these events could result in the suspension of drilling or production operations, claims by the operator, severe damage to or destruction of the property and equipment involved, injury or death to rig or liftboat personnel, and environmental damage. We may also be subject to personal injury and other claims of rig or liftboat personnel as a result of our drilling and liftboat operations. Operations also may be suspended because of machinery breakdowns, abnormal operating conditions, failure of subcontractors to perform or supply goods or services and personnel shortages.

In addition, our drilling and liftboat operations are subject to perils of marine operations, including capsizing, grounding, collision and loss or damage from severe weather. Tropical storms, hurricanes and other severe weather prevalent in the U.S. Gulf of Mexico, such as Hurricane Ida in November 2009, Hurricanes Gustav and Ike in September 2008, Hurricane Rita in September 2005, Hurricane Katrina in August 2005 and Hurricane Ivan in September 2004, could have a material adverse effect on our operations. During such severe weather conditions, our liftboats typically leave location and cease to earn a full dayrate. Under U.S. Coast Guard guidelines, the liftboats cannot return to work until the weather improves and seas are less than five feet. In addition, damage to our rigs, liftboats, shorebases and corporate infrastructure caused by high winds, turbulent seas, or unstable sea bottom conditions could potentially cause us to curtail operations for significant periods of time until the damages can be repaired.

Damage to the environment could result from our operations, particularly through oil spillage or extensive uncontrolled fires. We may also be subject to property, environmental and other damage claims by oil and natural gas companies and other businesses operating offshore and in coastal areas. Our insurance policies and contractual rights to indemnity may not adequately cover losses, and we may not have insurance coverage or rights to indemnity for all risks. Moreover, pollution and environmental risks generally are subject to significant deductibles and are not totally insurable. Risks from extreme weather and marine hazards may increase in the event of ongoing patterns of adverse changes in weather or climate.

A significant portion of our business is conducted in shallow-water areas of the U.S. Gulf of Mexico. The mature nature of this region could result in less drilling activity in the area, thereby reducing demand for our services.

The U.S. Gulf of Mexico, and in particular the shallow-water region of the U.S. Gulf of Mexico, is a mature oil and natural gas production region that has experienced substantial seismic survey and exploration activity for many years. Because a large number of oil and natural gas prospects in this region have already been drilled, additional prospects of sufficient size and quality could be more difficult to identify. According to the U.S. Energy Information Administration, the average size of the U.S. Gulf of Mexico discoveries has declined significantly since the early 1990s. In addition, the amount of natural gas production in the shallow-water U.S. Gulf of Mexico has declined over the last decade. Moreover, oil and natural gas companies may be unable to obtain financing necessary to drill prospects in this region. The decrease in the size of oil and natural gas prospects, the decrease in production or the failure to obtain such financing may result in reduced drilling activity in the U.S. Gulf of Mexico and reduced demand for our services.

We can provide no assurance that our current backlog of contract drilling revenue will be ultimately realized.

As of February 24, 2010, our total contract drilling backlog for our Domestic Offshore, International Offshore, International Liftboats and Inland segments was approximately $399.7 million, excluding the amount related to our Angola contract. We calculate our contract revenue backlog, or future contracted revenue, as the contract dayrate multiplied by the number of days remaining on the contract, assuming full utilization. Backlog excludes revenues for mobilization, demobilization, contract preparation and customer reimbursables. We may not be able to perform under our drilling contracts due to various operational factors, including unscheduled repairs, maintenance, operational delays, health, safety and environmental incidents, weather events in the Gulf of Mexico and elsewhere and other factors (some of which are beyond our control), and our customers may seek to cancel or renegotiate our contracts for various reasons, including the financial crisis or falling commodity prices. In some of the contracts, our customer has the right to terminate the contract without penalty and in certain instances, with little or no notice. 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 insurance coverage has become more expensive, may become unavailable in the future, and may be inadequate to cover our losses.

Our insurance coverage is subject to certain significant deductibles and levels of self-insurance, does not cover all types of losses and, in some situations, may not provide full coverage for losses or liabilities resulting from our operations. In addition, due to the losses sustained by us and the offshore drilling industry in recent years, primarily as a result of Gulf of Mexico hurricanes, we are likely to continue experiencing increased costs for available insurance coverage, which may impose higher deductibles and limit maximum aggregated recoveries, including for hurricane-related windstorm damage or loss. Insurance costs may increase in the event of ongoing patterns of adverse changes in weather or climate.

Further, we may not be able to obtain windstorm coverage in the future, thus putting us at a greater risk of loss due to severe weather conditions and other hazards. If a significant accident or other event resulting in damage to our rigs or liftboats, including severe weather, terrorist acts, piracy, war, civil disturbances, pollution or environmental damage, occurs and is not fully covered by insurance or a recoverable indemnity from a customer, it could adversely affect our financial condition and results of operations. Moreover, we may not be able to maintain adequate insurance in the future at rates we consider reasonable or be able to obtain insurance against certain risks.

As a result of a number of recent catastrophic events like Hurricanes Gustav, Ike, Ivan, Katrina and Rita, insurance underwriters increased insurance premiums for many of the coverages historically maintained and issued general notices of cancellation and significant changes for a wide variety of insurance coverages. The oil and natural gas industry suffered extensive damage from Hurricanes Gustav, Ike, Ivan, Katrina and Rita. As a result, over the past four years our insurance costs increased significantly, our deductibles increased and our coverage for named windstorm damage was restricted. Any additional severe storm activity in the energy producing areas of the U.S. Gulf of Mexico in the future could cause insurance underwriters to no longer insure U.S. Gulf of Mexico assets against weather-related damage. A number of our customers that produce oil and natural gas have previously maintained business interruption insurance for their production. This insurance is less available and may cease to be available in the future, which could adversely impact our customers business prospects in the U.S. Gulf of Mexico and reduce demand for our services.

Our customers may be unable or unwilling to indemnify us.

Consistent with standard industry practice, our clients generally assume, and indemnify us against, well control and subsurface risks under dayrate contracts. These risks are those associated with the loss of control of a well, such as blowout or cratering, the cost to regain control or redrill the well and associated pollution. There can be no assurance, however, that these clients will necessarily be financially able to indemnify us against all these risks. Also, we may be effectively prevented from enforcing these indemnities because of the nature of our relationship with some of our larger clients. Additionally, from time to time we may not be able to obtain agreement from our customer to indemnify us for such damages and risks.

Our international operations are subject to additional political, economic, and other uncertainties not generally associated with domestic operations.

An element of our business strategy is to continue to expand into international oil and natural gas producing areas such as West Africa, the Middle East and the Asia-Pacific region. We operate liftboats in West Africa, including Nigeria, and in the Middle East. We also operate drilling rigs in India, Southeast Asia, Saudi Arabia, Mexico and West Africa. Our international operations are subject to a number of risks inherent in any business operating in foreign countries, including:

- political, social and economic instability, war and acts of terrorism;

Table of Contents

- potential seizure, expropriation or nationalization of assets;
- damage to our equipment or violence directed at our employees, including kidnappings and piracy;
- increased operating costs;
- complications associated with repairing and replacing equipment in remote locations;
- repudiation, modification or renegotiation of contracts, disputes and legal proceedings in international jurisdictions;
- limitations on insurance coverage, such as war risk coverage in certain areas;
- import-export quotas;
- confiscatory taxation;
- work stoppages or strikes, particularly in the West African and Mexican labor environments;
- unexpected changes in regulatory requirements;
- wage and price controls;
- imposition of trade barriers;
- imposition or changes in enforcement of local content laws, particularly in West Africa where the legislatures are active in developing new legislation;
- restrictions on currency or capital repatriations;
- currency fluctuations and devaluations; and
- other forms of government regulation and economic conditions that are beyond our control.

In 2009, the level of political unrest, acts of terrorism, organized criminality and piracy in Nigeria decreased at certain periods. However, during the year, there were several attacks directed at the assets and operations of our largest customer, Chevron Corporation. The country is currently experiencing renewed political uncertainty due to the extended absence the president and the apparent transfer of power and authority to vice president. This political uncertainty could cause an increase in the level of political unrest, terrorism, organized criminality and piracy in Nigeria. In the past, many of our customers in Nigeria, including Chevron Corporation, have interrupted their activities during these episodes of increased terrorism, piracy and armed conflict. These interruptions in activity can be prolonged, during which time we may not receive dayrates for our liftboats.

Many governments favor or effectively require that liftboat or drilling contracts be awarded to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. These practices may result in inefficiencies or put us at a disadvantage when bidding for contracts against local competitors.

Our non-U.S. contract drilling and liftboat operations are subject to various laws and regulations in countries in which we operate, including laws and regulations relating to the equipment and operation of drilling rigs and liftboats, currency conversions and repatriation, oil and natural gas exploration and development, taxation of offshore earnings and earnings of expatriate personnel, the use of local employees and suppliers by foreign contractors and duties on the importation and exportation of 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 natural gas and other aspects of the oil and natural 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 natural gas companies and may continue to do so. Operations in developing countries can be subject to legal systems which are not as predictable as those in more developed countries, which can lead to greater risk and uncertainty in legal matters and proceedings.

Due to our international operations, we may experience currency exchange losses when revenues are received and expenses are paid in nonconvertible currencies or when we do not hedge an exposure to a foreign currency. We may also incur losses as a result of an inability to collect revenues because of a shortage of convertible currency available to the country of operation, controls over currency exchange or controls over the repatriation of income or capital.

A small number of customers account for a significant portion of our revenues, and the loss of one or more of these customers could adversely affect our financial condition and results of operations.

We derive a significant amount of our revenue from a few energy companies. Oil and Natural Gas Corporation Limited, Chevron Corporation, Saudi Aramco and PEMEX accounted for 16%, 14%, 13% and 10% of our revenues for the year ended December 31, 2009, respectively. Chevron Corporation represented approximately 12% and 21% of our consolidated revenues for the years ended December 31, 2008 and 2007, respectively. In addition, our financial condition and results of operations will be materially adversely affected if these customers interrupt or curtail their activities, terminate their contracts with us, fail to renew their existing contracts or refuse to award new contracts to us and we are unable to enter into contracts with new customers at comparable dayrates. The loss of any of these or any other significant customer could adversely affect our financial condition and results of operations.

Our results of operations for 2009 include $31.6 million ($20.5 million, net of taxes, or $0.21 per diluted share) related to (i) an allowance for doubtful accounts receivable of approximately $26.8 million associated with a customer in West Africa that is contracted to utilize one rig in our International Offshore segment, (ii) a non-cash charge of approximately $7.3 million to fully impair related deferred mobilization and contract preparation costs, partially offset by (iii) a $2.5 million reduction in previously accrued contract related operating costs that are not expected to be settled if the receivable is not collected.

Our jackup rigs are at a relative disadvantage to higher specification rigs, which may be more likely to obtain contracts than lower specification jackup rigs such as ours.

Many of our competitors have jackup fleets with generally higher specification rigs than those in our jackup fleet. In addition, the announced construction of new rigs includes approximately 60 higher specification jackup rigs. Further, 21 of our 30 jackup rigs are mat-supported, which are generally limited to geographic areas with soft bottom conditions like much of the Gulf of Mexico. Most of the rigs under construction are currently without contracts, which may intensify price competition as scheduled delivery dates occur. Particularly in periods in which there is decreased rig demand, such as the current period, higher specification rigs may be more likely to obtain contracts than lower specification jackup rigs such as ours. In the past, lower specification rigs have been stacked earlier in the cycle of decreased rig demand than higher specification rigs and have been reactivated later in the cycle, which may adversely impact our business. In addition, higher specification rigs may be more adaptable to different operating conditions and therefore have greater flexibility to move to areas of demand in response to changes in market conditions. Because a majority of our rigs were designed specifically for drilling in the shallow-water U.S. Gulf of Mexico, our ability to move them to other regions in response to changes in market conditions is limited.

Furthermore, in recent years, an increasing amount of exploration and production expenditures have been concentrated in deepwater drilling programs and deeper formations, including deep natural gas prospects, requiring higher specification jackup rigs, semisubmersible drilling rigs or drillships. This trend is expected to continue and could result in a decline in demand for lower specification jackup rigs like ours, which could have an adverse impact on our financial condition and results of operations. One of our customers, PEMEX, has indicated a shifting focus in drilling rig requirements since the beginning of 2008, with more emphasis placed on independent leg cantilever rigs rated for 250 foot water depth or greater, versus mat-supported cantilever rigs rated for 200 foot water depth. Demand in Mexico for our 200 foot mat-supported cantilever fleet declined and the future contracting opportunities for such rigs in Mexico could diminish.

We may consider future acquisitions and may be unable to complete and finance future acquisitions on acceptable terms. In addition, we may fail to successfully integrate acquired assets or businesses we acquire or incorrectly predict operating results.

We may consider future acquisitions which could involve the payment by us of a substantial amount of cash, the incurrence of a substantial amount of debt or the issuance of a substantial amount of equity. Unless we have achieved a specified leverage ratio, our Credit Agreement restricts our ability to make acquisitions involving the payment of cash or the incurrence of debt. If we are restricted from using cash or incurring debt to fund a potential acquisition, we may not be able to issue, on terms we find acceptable, sufficient equity that may be required for any such permitted acquisition or investment. In addition, barring any restrictions under the Credit Agreement, we still may not be able to obtain, on terms we find acceptable, sufficient financing or funding that may be required for any such acquisition or investment.

We cannot predict the effect, if any, that any announcement or consummation of an acquisition would have on the trading price of our common stock.

Any future acquisitions could present a number of risks, including:

- the risk of incorrect assumptions regarding the future results of acquired operations or assets or expected cost reductions or other synergies expected to be realized as a result of acquiring operations or assets;
- the risk of failing to integrate the operations or management of any acquired operations or assets successfully and timely; and
- the risk of diversion of management s attention from existing operations or other priorities.

If we are unsuccessful in integrating our acquisitions in a timely and cost-effective manner, our financial condition and results of operations could be adversely affected.

Failure to retain or attract skilled workers could hurt our operations.

We require skilled personnel to operate and provide technical services and support for our rigs and liftboats. The shortages of qualified personnel or the inability to obtain and retain qualified personnel could negatively affect the quality and timeliness of our work. In periods of economic crisis or during a recession, we may have difficulty attracting and retaining our skilled workers as these workers may seek employment in less cyclical or volatile industries or employers. In periods of recovery or increasing activity, we may have to increase the wages of our skilled workers, which could negatively impact our operations and financial results.

Although our domestic employees are not covered by a collective bargaining agreement, the marine services industry has been targeted by maritime labor unions in an effort to organize U.S. Gulf of Mexico employees. A significant increase in the wages paid by competing employers or the unionization of our U.S. Gulf of Mexico employees could result in a reduction of our skilled labor force, increases in the wage rates that we must pay, or both. If either of these events were to occur, our capacity and profitability could be diminished and our growth potential could be impaired.

Governmental laws and regulations, including those related to climate and emissions of greenhouse gases, may add to our costs or limit drilling activity and liftboat operations.

Our operations are affected in varying degrees by governmental laws and regulations. We are also subject to the jurisdiction of the United States Coast Guard, the National Transportation Safety Board and the United States

Customs and Border Protection Service, as well as private industry organizations such as the American Bureau of Shipping. We may be required to make significant capital expenditures to comply with laws and the applicable regulations and standards of governmental authorities and organizations. Moreover, the cost of compliance could be higher than anticipated. Similarly, our international operations are subject to compliance with the U.S. Foreign Corrupt Practices Act, certain international conventions and the laws, regulations and standards of other foreign countries in which we operate. It is also possible that existing and proposed governmental conventions, laws, regulations and standards, including those related to climate and emissions of greenhouse gases, may in the future add significantly to our operating costs or limit our activities or the activities and levels of capital spending by our customers.

In addition, as our vessels age, the costs of drydocking the vessels in order to comply with governmental laws and regulations and to maintain their class certifications are expected to increase, which could adversely affect our financial condition and results of operations.

Compliance with or a breach of environmental laws can be costly and could limit our operations.

Our operations are subject to regulations that require us to obtain and maintain specified permits or other governmental approvals, control the discharge of materials into the environment, require the removal and cleanup of materials that may harm the environment or otherwise relate to the protection of the environment. For example, as an operator of mobile offshore drilling units and liftboats in navigable U.S. waters and some offshore areas, we may be liable for damages and costs incurred in connection with oil spills or other unauthorized discharges of chemicals or wastes resulting from those operations. Laws and regulations protecting the environment have become more stringent in recent years, 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 that were in compliance with all applicable laws at the time they were performed. The application of these requirements, the modification of existing laws or regulations or the adoption of new requirements, both in U.S. waters and internationally, could have a material adverse effect on our financial condition and results of operations.

We may not be able to maintain or replace our rigs and liftboats as they age.

The capital associated with the repair and maintenance of our fleet increases with age. We may not be able to maintain our fleet by extending the economic life of existing rigs and liftboats, and our financial resources may not be sufficient to enable us to make expenditures necessary for these purposes or to acquire or build replacement units.

Our operating and maintenance costs with respect to our rigs include fixed costs that will not decline in proportion to decreases in dayrates.

We do not expect our operating and maintenance costs with respect to our rigs to necessarily fluctuate in proportion to changes in operating revenues. Operating revenues may fluctuate as a function of changes in dayrate, but costs for operating a rig are generally fixed or only semi-variable regardless of the dayrate being earned. Additionally, if our rigs incur idle time between contracts, we typically do not de-man those rigs because we will use 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.

Upgrade, refurbishment and repair projects are subject to risks, including delays and cost overruns, which could have an adverse impact on our available cash resources and results of operations.

We make upgrade, refurbishment and repair expenditures for our fleet from time to time, including when we acquire units or when repairs or upgrades are required by law, in response to an inspection by a governmental authority or when a unit is damaged. We also regularly make certain upgrades or modifications to our drilling rigs to meet customer or contract specific requirements. Upgrade, refurbishment and repair projects are subject to the risks of delay or cost overruns inherent in any large construction project, including costs or delays resulting from the following:

- unexpectedly long delivery times for, or shortages of, key equipment, parts and materials;
- shortages of skilled labor and other shipyard personnel necessary to perform the work;
- unforeseen increases in the cost of equipment, labor and raw materials, particularly steel;
- unforeseen design and engineering problems;
- latent damages to or deterioration of hull, equipment and machinery in excess of engineering estimates and assumptions;
- unanticipated actual or purported change orders;
- work stoppages;
- failure or delay of third-party service providers and labor disputes;
- disputes with shipyards and suppliers;
- delays and unexpected costs of incorporating parts and materials needed for the completion of projects;
- failure or delay in obtaining acceptance of the rig from our customer;
- financial or other difficulties at shipyards;
- adverse weather conditions; and
- inability or delay in obtaining customer acceptance or flag-state, classification society, certificate of inspection, or regulatory approvals.

Significant cost overruns or delays would adversely affect our financial condition and results of operations. Additionally, capital expenditures for rig upgrade and refurbishment projects could exceed our planned capital expenditures. Failure to complete an upgrade, refurbishment or repair project on time may, in some circumstances, result in the delay, renegotiation or cancellation of a drilling or liftboat contract and could put at risk our planned arrangements to commence operations on schedule. We also could be exposed to penalties for failure to complete an upgrade, refurbishment or repair project and commence operations in a timely manner. Our rigs and liftboats undergoing upgrade, refurbishment or repair generally do not earn a dayrate during the period they are out of service.

We are subject to litigation that could have an adverse effect on us.

We are from time to time involved in various litigation matters. The numerous operating hazards inherent in our business increases our exposure to litigation, including personal injury litigation brought against us by our employees that are injured operating our rigs and liftboats. These matters may include, among other things, contract dispute, personal injury, environmental, asbestos and other toxic tort, employment, tax and securities litigation, and litigation that arises in the ordinary course of our business. We have extensive litigation brought against us in federal and state courts located in Louisiana, Mississippi and South Texas, areas that were significantly impacted by the hurricanes in

2005 and, more recently, by Hurricanes Gustav and Ike. The jury pools in these areas have become increasingly more hostile to defendants, particularly corporate defendants in the oil and gas industry. We cannot predict with certainty the outcome or effect of any claim or other litigation matter. Litigation may have an adverse effect on us because of potential negative outcomes, the costs associated with defending the lawsuits, the diversion of our management s resources and other factors.

TODCO s tax sharing agreement with Transocean may require continuing substantial payments.

We, as successor to TODCO, and TODCO s former parent Transocean Holdings Inc., or Transocean, are parties to a tax sharing agreement that was originally entered into in connection with TODCO s initial public offering in 2004. The tax sharing agreement was amended and restated in November 2006. The tax sharing

Table of Contents

agreement required us to make an acceleration payment to Transocean upon completion of the TODCO acquisition. Additionally, the tax sharing agreement continues to require that additional payments be made to Transocean based on a portion of the expected tax benefit from the exercise of certain compensatory stock options to acquire Transocean common stock attributable to current and former TODCO employees and board members. The estimated amount of payments to Transocean related to compensatory options that remained outstanding at December 31, 2009, assuming a Transocean stock price of $82.80 per share at the time of exercise of the compensatory options (the actual price of Transocean s common stock at December 31, 2009), was approximately $1.1 million. There is no certainty that we will realize future economic benefits from TODCO s tax benefits equal to the amount of the payments required under the tax sharing agreement.

Changes in effective tax rates, taxation of our foreign subsidiaries, limitations on utilization of our net operating losses or adverse outcomes resulting from examination of our tax returns could adversely affect our operating results and financial results.

Our future effective tax rates could be adversely affected by changes in tax laws, both domestically and internationally. From time to time, Congress and foreign, state and local governments consider legislation that could increase our effective tax rates. We cannot determine whether, or in what form, legislation will ultimately be enacted or what the impact of any such legislation would be on our profitability. If these or other changes to tax laws are enacted, our profitability could be negatively impacted.

Our future effective tax rates could also be adversely affected by changes in the valuation of our deferred tax assets and liabilities, or by changes in tax treaties, regulations, accounting principles or interpretations thereof in one or more countries in which we operate. In addition, we are subject to the potential examination of our income tax returns by the Internal Revenue Service and other tax authorities where we file tax returns. We regularly assess the likelihood of adverse outcomes resulting from these examinations to determine the adequacy of our provision for taxes. There can be no assurance that such examinations will not have an adverse effect on our operating results and financial condition.

Our business would be adversely affected if we failed to comply with the provisions of U.S. law on coastwise trade, or if those provisions were modified, repealed or waived.

We are subject to U.S. federal laws that restrict maritime transportation, including liftboat services, between points in the United States to vessels built and registered in the United States and owned and manned by U.S. citizens. We are responsible for monitoring the ownership of our common stock. If we do not comply with these restrictions, we would be prohibited from operating our liftboats in U.S. coastwise trade, and under certain circumstances we would be deemed to have undertaken an unapproved foreign transfer, resulting in severe penalties, including permanent loss of U.S. coastwise trading rights for our liftboats, fines or forfeiture of the liftboats.

During the past several years, interest groups have lobbied Congress to repeal these restrictions to facilitate foreign flag competition for trades currently reserved for U.S.-flag vessels under the federal laws. We believe that interest groups may continue efforts to modify or repeal these laws currently benefiting U.S.-flag vessels. If these efforts are successful, it could result in increased competition, which could adversely affect our results of operations.

Our liquidity depends upon cash on hand, cash from operations and availability under our revolving credit facility.

Our liquidity depends upon cash on hand, cash from operations and availability under our revolving credit facility. In the amendment to our Credit Facility, we reduced the size of our revolving credit facility from $250.0 million to $175.0 million. The availability under the revolving credit facility is to be used for working capital, capital expenditures and other general corporate purposes and cannot be used to prepay outstanding term loans under our credit facility. All borrowings under the revolving credit facility mature on July 11, 2012, and the revolving credit facility requires interest-only payments on a quarterly basis until the maturity date. No amounts were outstanding under the revolving credit facility as of December 31, 2009, although

$10.0 million in stand-by letters of credit had been issued under it. The remaining availability under the revolving credit facility is currently $165.0 million at December 31, 2009.

We also maintain a shelf registration statement covering the future issuance from time to time of various types of securities, including debt and equity securities. If we issue any debt securities off the shelf registration statement or otherwise incur debt, we may be required to make payments on our term loan. We currently believe we will have adequate liquidity to fund our operations for the foreseeable future. However, to the extent we do not generate sufficient cash from operations, we may need to raise additional funds through public or private debt or equity offerings to fund operations and under the terms of the amendment to our credit facility, we may be required to use the proceeds of any capital that we raise to repay existing indebtedness. Furthermore, we may need to raise additional funds through public or private debt or equity offerings or asset sales to avoid a breach of our financial covenants in our Credit Facility to refinance our indebtedness or for general corporate purposes.

We are a holding company, and we are dependent upon cash flow from subsidiaries to meet our obligations.

We currently conduct our operations through, and most of our assets are owned by, both U.S. and foreign subsidiaries, and our operating income and cash flow are generated by our subsidiaries. As a result, cash we obtain from our subsidiaries is the principal source of funds necessary to meet our debt service obligations. Contractual provisions or laws, as well as our subsidiaries financial condition and operating requirements, may limit our ability to obtain cash from our subsidiaries that we require to pay our debt service obligations, including payments on our convertible notes. Applicable tax laws may also subject such payments to us by our subsidiaries to further taxation.

The inability to transfer cash from our subsidiaries to us may mean that, even though we may have sufficient resources on a consolidated basis to meet our obligations, we may not be permitted to make the necessary transfers from subsidiaries to the parent company in order to provide funds for the payment of the parent company s obligations.

We limit foreign ownership of our company, which may restrict investment in our common stock and could reduce the price of our common stock.

Our certificate of incorporation limits the percentage of outstanding common stock and other classes of capital stock that can be owned by non-United States citizens within the meaning of statutes relating to the ownership of U.S.-flagged vessels. Applying the statutory requirements applicable today, our certificate of incorporation provides that no more than 20% of our outstanding common stock may be owned by non-United States citizens and establishes mechanisms to maintain compliance with these requirements. These restrictions may have an adverse impact on the liquidity or market value of our common stock because holders may be unable to transfer our common stock to non-United States citizens. Any attempted or purported transfer of our common stock in violation of these restrictions will be ineffective to transfer such common stock or any voting, dividend or other rights in respect of such common stock.

Our certificate of incorporation also provides that any transfer, or attempted or purported transfer, of any shares of our capital stock that would result in the ownership or control of in excess of 20% of our outstanding capital stock by one or more persons who are not United States citizens for purposes of U.S. coastwise shipping will be void and ineffective as against us. In addition, if at any time persons other than United States citizens own shares of our capital stock or possess voting power over any shares of our capital stock in excess of 20%, we may withhold payment of dividends, suspend the voting rights attributable to such shares and redeem such shares.

We have no plans to pay regular dividends on our common stock, so investors in our common stock may not receive funds without selling their shares.

We do not intend to declare or pay regular dividends on our common stock in the foreseeable future. Instead, we generally intend to invest any future earnings in our business. Subject to Delaware law, our board of directors will determine the payment of future dividends on our common stock, if any, and the amount of any dividends in light of any applicable contractual restrictions limiting our ability to pay dividends, our earnings and cash flows, our capital requirements, our financial condition, and other factors our board of directors deems relevant. Our Credit Agreement restricts our ability to pay dividends or other distributions on our equity securities. Accordingly, stockholders may have to sell some or all of their common stock in order to generate cash flow from their investment. Stockholders may not receive a gain on their investment when they sell our common stock and may lose the entire amount of their investment.

Provisions in our charter documents, stockholder rights plan or Delaware law may inhibit a takeover, which could adversely affect the value of our common stock.

Our certificate of incorporation, bylaws, stockholder rights plan and Delaware corporate law contain provisions that could delay or prevent a change of control or changes in our management that a stockholder might consider favorable. These provisions will apply even if the offer may be considered beneficial by some of our stockholders. If a change of control or change in management is delayed or prevented, the market price of our common stock could decline.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

Our property consists primarily of jackup rigs, barge rigs, submersible rigs, a platform rig, marine support vessels, liftboats and ancillary equipment, substantially all of which we own. Several of our vessels and substantially all of our other personal property, are pledged to collateralize our Credit Agreement and 10.5% Senior Secured Notes.

We maintain our principal executive office in Houston, Texas, which is under lease. We own an office building, yard facilities and warehouses and lease yard facilities and a waterfront dock in Houma, Louisiana. We lease office space in Lafayette, Louisiana; Al Khobar, Saudi Arabia; and Ciudad del Carmen, Mexico. We also lease a warehouse, yard facilities and office space in Broussard, Louisiana and lease warehouses and yard facilities in Al Khobar, Saudi Arabia. We lease warehouses, office space and residential premises in India and Nigeria and warehouses, yard facilities, office space, and residential premises in Malaysia. In addition, we lease a waterfront dock, yard facilities and a maintenance facility in Nigeria and an office and a residential premises in Cayman Islands, Qatar and Angola.

We incorporate by reference in response to this item the information set forth in Item 1 of this annual report.

Item 3. ***Legal Proceedings***

In connection with our acquisition of TODCO, we also assumed certain other material legal proceedings from TODCO and its subsidiaries.

In October 2001, TODCO was notified by the U.S. Environmental Protection Agency (EPA) that the EPA had identified a subsidiary of TODCO as a potentially responsible party under CERCLA in connection with the Palmer Barge Line superfund site located in Port Arthur, Jefferson County, Texas. Based upon the information provided by the EPA and our review of our internal records to date, we dispute our designation as a potentially responsible party and do not expect that the ultimate outcome of this case will have a material adverse effect on our consolidated results of operations, financial position or cash flows. We continue to monitor this matter.

Robert E. Aaron et al. vs. Phillips 66 Company et al. Circuit Court, Second Judicial District, Jones County, Mississippi. This is the case name used to refer to several cases that have been filed in the Circuit Courts of the State of Mississippi involving 768 persons that allege personal injury or whose heirs claim their deaths arose out of asbestos exposure in the course of their employment by the defendants between 1965 and 2002. The complaints name as defendants, among others, certain of TODCO s subsidiaries and certain subsidiaries of TODCO s former parent to whom TODCO may owe indemnity and other unaffiliated defendant companies, including companies that allegedly manufactured drilling related products containing asbestos that are the subject of the complaints. The number of unaffiliated defendant companies involved in each complaint ranges from approximately 20 to 70. The complaints allege that the defendant drilling contractors used asbestos-containing products in offshore drilling operations, land based drilling operations and in drilling structures, drilling rigs, vessels and other equipment and assert claims based on, among other things, negligence and strict liability, and claims authorized under the Jones Act. The plaintiffs seek, among other things, awards of unspecified compensatory and punitive damages. All of these cases were assigned to a special master who has approved a form of questionnaire to be completed by plaintiffs so that claims made would be properly served against specific defendants. Approximately 700 questionnaires were returned and the remaining plaintiffs, who did not submit a questionnaire reply, have had their suits dismissed without prejudice. Of the respondents, approximately 100 shared periods of employment by TODCO and its former parent which could lead to claims against either company, even though many of these plaintiffs did not state in their questionnaire answers that the employment actually involved exposure to asbestos. After providing the questionnaire, each plaintiff was further required to file a separate and individual amended complaint naming only those defendants against whom they had a direct claim as identified in the questionnaire answers. Defendants not identified in the amended complaints were dismissed from the plaintiffs litigation. To date, three plaintiffs named TODCO as a defendant in their amended complaints. It is possible that some of the plaintiffs who have filed amended complaints and have not named TODCO as a defendant may attempt to add TODCO as a defendant in the future when case discovery begins and greater attention is given to each individual plaintiff s employment background. We continue to monitor a small group of these other cases. We have not determined which entity would be responsible for such claims under the Master Separation Agreement between TODCO and its former parent. We intend to defend ourselves vigorously and do not expect the ultimate outcome of these lawsuits to have a material adverse effect on our consolidated results of operations, financial position or cash flows.

We and our subsidiaries are involved in a number of other lawsuits, all of which have arisen in the ordinary course of our business. We do not believe that ultimate liability, if any, resulting from any such other pending litigation will have a material adverse effect on our business or consolidated financial position. However, we cannot predict with certainty the outcome or effect of any of the litigation matters specifically described above or of any such other pending litigation. There can be no assurance that our belief or expectations as to the outcome or effect of any lawsuit or other litigation matter will prove correct, and the eventual outcome of these matters could materially differ from management s current estimates.

Item 4. ***Reserved***

PART II

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

Quarterly Common Stock Prices and Dividend Policy

Our common stock is traded on the NASDAQ Global Select Market under the symbol HERO. As of February 24, 2010, there were 115 stockholders of record. On February 24, 2010, the closing price of our common stock as reported by NASDAQ was $3.89 per share. The following table sets forth, for the periods indicated, the range of high and low sales prices for our common stock:

	Price	
	High	**Low**

2009		
Fourth Quarter	$ 6.60	$ 4.21
Third Quarter	7.28	3.02
Second Quarter	5.64	1.54
First Quarter	5.92	1.07

	Price High	Price Low
2008		
Fourth Quarter	$ 14.94	$ 3.06
Third Quarter	39.35	13.08
Second Quarter	39.47	24.07
First Quarter	27.52	20.00

We have not paid any cash dividends on our common stock since becoming a publicly held corporation in October 2005, and we do not intend to declare or pay regular dividends on our common stock in the foreseeable future. Instead, we generally intend to invest any future earnings in our business. Subject to Delaware law, our board of directors will determine the payment of future dividends on our common stock, if any, and the amount of any dividends in light of any applicable contractual restrictions limiting our ability to pay dividends, our earnings and cash flows, our capital requirements, our financial condition, and other factors our board of directors deems relevant. Our Credit Agreement and 10.5% Senior Secured Notes restrict our ability to pay dividends or other distributions on our equity securities.

Issuer Purchases of Equity Securities

The following table sets forth for the periods indicated certain information with respect to our purchases of our common stock:

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of a Publicly Announced Plan(2)	Maximum Number of Shares that may yet be Purchased Under the Plan(2)
October 1 - 31, 2009	653	$ 5.13	N/A	N/A
November 1 - 30, 2009	133	5.28	N/A	N/A
December 1 - 31, 2009	158	5.01	N/A	N/A
Total	944	5.13	N/A	N/A

(1) Represents the surrender of shares of our common stock to satisfy tax withholding obligations in connection with the vesting of restricted stock issued to employees under our stockholder-approved long-term incentive plan.

(2) We did not have at any time during 2009, 2008 or 2007, and currently do not have, a share repurchase program in place.

Item 6. ***Selected Financial Data***

We have derived the following condensed consolidated financial information as of December 31, 2009 and 2008 and for the years ended December 31, 2009, 2008 and 2007 from our audited consolidated financial statements included in Item 8 of this annual report. The condensed consolidated financial information as of December 31, 2007 and for the year ended December 31, 2006 was derived from our audited consolidated financial statements included in Item 8 of our Annual report on Form 10-K for the year ended December 31, 2008, as amended by our current report on Form 8-K filed on September 23, 2009. The condensed consolidated financial information as of December 31, 2006 and 2005 and for the year ended December 31, 2005 was derived from our audited consolidated financial statements included in Item 8 of our annual report on Form 10-K, as amended, for the year ended December 31, 2006.

We were formed in July 2004 and commenced operations in August 2004. From our formation to December 31, 2009, we completed the acquisition of TODCO and several significant asset acquisitions that

Table of Contents

impact the comparability of our historical financial results. Our financial results reflect the impact of the TODCO business and the asset acquisitions from the dates of closing. We have included pro forma information related to the TODCO acquisition in Note 4 to the Consolidated Financial Statements included in Item 8 of this annual report.

In addition, in connection with our initial public offering, we converted from a Delaware limited liability company to a Delaware corporation on November 1, 2005. Upon the conversion, each outstanding membership interest of the limited liability company was converted to 350 shares of common stock of the corporation. Share-based information contained herein assumes that we had effected the conversion of each outstanding membership interest into 350 shares of common stock for all periods prior to the conversion. Prior to the conversion, our owners elected to be taxed at the member unit holder level rather than at the company level. As a result, we did not recognize any tax provision on our income prior to the conversion. Upon completion of the conversion, we recorded a tax provision of $12.1 million related to the recognition of deferred taxes equal to the tax effect of the difference between the book and tax basis of our assets and liabilities as of the effective date of the conversion.

The selected consolidated financial information below should be read together with Management s Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this annual report and our audited consolidated financial statements and related notes included in Item 8 of this annual report. In addition, the following information may not be deemed indicative of our future operations.

	Year Ended December 31, 2009(a)	Year Ended December 31, 2008(b)	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
	(In thousands, except per share data)				
Statement of Operations Data:					
Revenues	$ 742,851	$ 1,111,807	$ 726,278	$ 344,312	$ 161,334
Operating income (loss)	(92,146)	(1,120,913)	225,642	158,057	55,859
Income (loss) from continuing operations	(90,149)	(1,081,870)	136,012	119,050	27,456
Earnings (loss) per share from continuing operations:					
Basic	$ (0.93)	$ (12.25)	$ 2.31	$ 3.80	$ 1.10
Diluted	(0.93)	(12.25)	2.28	3.70	1.08
Balance Sheet Data (as of end of period):					
Cash and cash equivalents	$ 140,828	$ 106,455	$ 212,452	$ 72,772	$ 47,575
Working capital	144,813	224,785	367,117	110,897	70,083
Total assets	2,277,476	2,590,895	3,643,948	605,581	354,825
Long-term debt, net of current portion	856,755	1,015,764	890,013	91,850	93,250
Total stockholders equity	978,512	925,315	2,011,433	394,851	215,943
Cash dividends per share					

(a) Includes $26.9 million ($13.1 million, net of taxes or $0.13 per diluted share) of impairment charges related to the write-down of the *Hercules 110* to fair value less costs to sell during the second quarter of 2009. The sale of the rig was completed in August 2009. In addition, 2009 includes $31.6 million ($20.5 million, net of taxes or $0.21 per diluted share) related to an allowance for doubtful accounts receivable of approximately $26.8 million, associated with a customer in our International Offshore segment, a non-cash charge of approximately $7.3 million to fully impair the related deferred mobilization and contract preparation costs, partially offset by a $2.5 million reduction in previously accrued contract related operating costs that are not expected to be settled if the receivable is not collected.

(b) Includes $950.3 million ($950.3 million, net of taxes or $10.76 per diluted share) and $376.7 million ($236.7 million, net of taxes or $2.68 per diluted share) in impairment of goodwill and impairment of property and equipment charges, respectively.

	Year Ended December 31, 2009	Year Ended December 31, 2008	Year Ended December 31, 2007 (In thousands)	Year Ended December 31, 2006	Year Ended December 31, 2005
Other Financial Data:					
Net cash provided by (used in):					
Operating activities	$ 138,919	$ 269,948	$ 175,741	$ 124,241	$ 54,762
Investing activities	(60,510)	(515,787)	(825,007)	(149,983)	(174,952)
Financing activities	(44,036)	139,842	788,946	50,939	153,305
Capital expenditures	76,141	585,084(a)	155,390	204,456	168,038
Deferred drydocking expenditures	15,646	17,269	20,772	12,544	7,369

(a) Includes the purchase of *Hercules 350*, *Hercules 262* and *Hercules 261* as well as related equipment.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the accompanying consolidated financial statements as of December 31, 2009 and 2008 and for the years ended December 31, 2009, 2008 and 2007 included in Item 8 of this annual report. 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 Risk Factors in Item 1A and elsewhere in this annual report. See Forward-Looking Statements .

OVERVIEW

We are a leading provider of shallow-water drilling and marine services to the oil and natural gas exploration and production industry globally. We provide these services to national oil and gas companies, major integrated energy companies and independent oil and natural gas operators. As of February 24, 2010, we owned a fleet of 30 jackup rigs, 17 barge rigs, three submersible rigs, one platform rig, a fleet of marine support vessels and 60 liftboat vessels. In addition, we operate five liftboat vessels owned by a third party. We own four retired jackup rigs and eight retired inland barges, all located in the U.S. Gulf of Mexico, which are currently not expected to re-enter active service. We have operations in nine countries on three continents. Our diverse fleet is capable of providing services such as oil and gas exploration and development drilling, well service, platform inspection maintenance and decommissioning operations.

In January 2009, we reclassified four of our cold-stacked jackup rigs located in the U.S. Gulf of Mexico and 10 of our cold-stacked inland barges as retired; subsequently in each of September and November 2009, we sold one retired inland barge for approximately $0.2 million and $0.4 million, respectively. Additionally, we recently entered into an agreement to sell our retired jackups *Hercules 191* and *Hercules 255* for $5.0 million each and in February 2010, we entered into an agreement to sell six of our retired barges for $3.0 million.

In July 2007, we completed the acquisition of TODCO for total consideration of approximately $2.4 billion, consisting of $925.8 million in cash and 56.6 million shares of common stock. TODCO, a provider of contract drilling and marine services in the U.S. Gulf of Mexico and international markets, owned and operated 24 jackup rigs, 27 barge rigs, three submersible rigs, nine land rigs, one platform rig and a fleet of marine support vessels. The TODCO acquisition positioned us as a leading shallow-water drilling provider as well as expanded our international presence and diversified our fleet. We sold our nine land rigs and related equipment in the fourth quarter of 2007 and the results of operations of the land rig operations are reflected in the Consolidated Statements of Operations as a discontinued operation for all periods presented. In the first quarter of 2008, we furthered our strategic growth initiative by purchasing two jackup drilling rigs and related equipment for $220.0 million. In addition, during the second quarter of 2008, we purchased a third jackup rig and related equipment for $100.0 million.

We report our business activities in six business segments which as of February 24, 2010, included the following:

Domestic Offshore includes 22 jackup rigs and three submersible rigs in the U.S. Gulf of Mexico that can drill in maximum water depths ranging from 85 to 350 feet. Eleven of the jackup rigs are either working on short-term contracts or available for contracts, ten are cold-stacked and one is mobilizing to the U.S. Gulf of Mexico from Mexico. All three submersibles are cold-stacked.

International Offshore includes 8 jackup rigs and one platform rig outside of the U.S. Gulf of Mexico. We have two jackup rigs working offshore in each of India and Saudi Arabia. We have one jackup rig contracted offshore in Malaysia and one platform rig under contract in Mexico. In addition, we have one jackup rig warm-stacked in each of Bahrain and Gabon and one jackup rig contracted to a customer in Angola, however, the rig is currently on stand-by in Gabon. In August 2009, we closed the sale of the *Hercules 110* which was cold-stacked in Trinidad.

Inland includes a fleet of 6 conventional and 11 posted barge rigs that operate inland in marshes, rivers, lakes and shallow bay or coastal waterways along the U.S. Gulf Coast. Three of our inland barges are either operating on short-term contracts or available and 14 are cold-stacked.

Domestic Liftboats includes 41 liftboats in the U.S. Gulf of Mexico. Thirty-eight are operating and three are cold-stacked.

International Liftboats includes 24 liftboats. Twenty-two are operating or available for contracts offshore West Africa, including five liftboats owned by a third party and two are operating or available for contracts in the Middle East region.

Delta Towing our Delta Towing business operates a fleet of 29 inland tugs, 12 offshore tugs, 34 crew boats, 46 deck barges, 16 shale barges and five spud barges along and in the U.S. Gulf of Mexico and along the Southeastern coast and from time to time in Mexico. Of these vessels, 21 crew boats, 16 inland tugs, five offshore tugs, one deck barge and one spud barge are cold-stacked, and the remaining are working or available for contracts.

In December 2009, we entered into an agreement with First Energy Bank B.S.C. (MENAdrill) whereby we would market, manage and operate two Friede & Goldman Super M2 design new-build jackup drilling rigs each with a maximum water depth of 300 feet. The rigs are currently under construction and are scheduled to be delivered in the fourth quarter of 2010. We are actively marketing the rigs on an exclusive and worldwide basis.

In January 2010, we entered into an agreement with SKDP 1 Ltd., an affiliate of Skeie Drilling & Production ASA, to market, manage and operate an ultra high specification KFESL Class N new-build jackup drilling rig with a maximum water depth of 400 feet. The rig is currently under construction and is scheduled to be delivered in either the third or fourth quarter of 2010, depending upon the exercise of certain options available to the owner. The agreement is limited to a specified opportunity in the Middle East.

We had previously entered into similar agreements with Mosvold Middle East Jackup I Ltd. and Mosvold Middle East Jackup II Ltd. to market, manage and operate two Friede & Goldman Super M2 design new-build jackup rigs. We later terminated these agreements by mutual agreement due to uncertainties in the timing of the delivery of the rigs and disputes between the owner and the builder of the rigs.

Our jackup and submersible rigs and our barge rigs are used primarily for exploration and development drilling in shallow waters. Under most of our contracts, we are paid a fixed daily rental rate called a dayrate, and we are required to pay all costs associated with our own crews as well as the upkeep and insurance of the rig and equipment.

Our liftboats are self-propelled, self-elevating vessels that support a broad range of offshore support services, including platform maintenance, platform construction, well intervention and decommissioning services throughout the life of an oil or natural gas well. Under most of our liftboat contracts, we are paid a fixed dayrate for the rental of the vessel, which typically includes the costs of a small crew of four to eight employees, and we also receive a variable rate for reimbursement of other operating costs such as catering, fuel, rental equipment and other items.

Our revenues are affected primarily by dayrates, fleet utilization, the number and type of units in our fleet and mobilization fees received from our customers. Utilization and dayrates, in turn, are influenced principally by the demand for rig and liftboat services from the exploration and production sectors of the oil and natural gas industry. Our contracts in the U.S. Gulf of Mexico tend to be short-term in nature and are heavily influenced by changes in the supply of units relative to the fluctuating expenditures for both drilling and production activity. Our international drilling contracts and some of our liftboat contracts in West Africa are longer term in nature.

Our operating costs are primarily a function of fleet configuration and utilization levels. The most significant direct operating costs for our Domestic Offshore, International Offshore and Inland segments are wages paid to crews, maintenance and repairs to the rigs, and insurance. These costs do not vary significantly whether the rig is operating under contract or idle, unless we believe that the rig is unlikely to work for a prolonged period of time, in which case we may decide to cold-stack or warm-stack the rig. Cold-stacking is a common term used to describe a rig that is expected to be idle for a protracted period and typically for which routine maintenance is suspended and the crews are either redeployed or laid-off. When a rig is cold-stacked, operating expenses for the rig are significantly reduced because the crew is smaller and maintenance activities are suspended. Placing rigs in service that have been cold-stacked typically requires a lengthy reactivation project that can involve significant expenditures and potentially additional regulatory review, particularly if the rig has been cold-stacked for a long period of time. Warm-stacking is a term used for a rig expected to be idle for a period of time that is not as prolonged as is the case with a cold-stacked rig. Maintenance is continued for warm-stacked rigs. Crews are reduced but a small crew is retained. Warm-stacked rigs generally can be reactivated in three to four weeks.

The most significant costs for our Domestic Liftboats and International Liftboats segments are the wages paid to crews and the amortization of regulatory drydocking costs. Unlike our Domestic Offshore, International Offshore and Inland segments, a significant portion of the expenses incurred with operating each liftboat are paid for or reimbursed by the customer under contractual terms and prices. This includes catering, fuel, oil, rental equipment, crane overtime and other items. We record reimbursements from customers as revenues and the related expenses as operating costs. Our liftboats are required to undergo regulatory inspections every year and to be drydocked two times every five years; the drydocking expenses and length of time in drydock vary depending on the condition of the vessel. All costs associated with regulatory inspections, including related drydocking costs, are deferred and amortized over a period of twelve months.

RESULTS OF OPERATIONS

On July 11, 2007, we completed the acquisition of TODCO for total consideration of approximately $2.4 billion, consisting of $925.8 million in cash and 56.6 million shares of common stock. Our results include activity from this acquired business (Acquired Assets) from the date of acquisition.

On average, domestic industry conditions were generally weaker in 2009 as evidenced by lower utilization and average jackup, inland barge and liftboat dayrates in 2009 as compared to 2008. Although International industry conditions weakened during 2009 with lower demand for jackups and an increasing supply of jackups, our results were less impacted due to our longer-term contracts and primarily fixed dayrate contracts.

Table of Contents

The following table sets forth financial information by operating segment and other selected information for the periods indicated:

	Year Ended December 31, 2009	2008	2007
	(Dollars in thousands)		
Domestic Offshore:			
Number of rigs (as of end of period)	24	27	27
Revenues	$ 140,889	$ 382,358	$ 241,452
Operating expenses	175,473	227,884	122,131
Impairment of goodwill		507,194	
Impairment of property and equipment		174,613	
Depreciation and amortization expense	60,775	66,850	35,143
General and administrative expenses	6,496	4,673	6,105
Operating income (loss)	$ (101,855)	$ (598,856)	$ 78,073
International Offshore:			
Number of rigs (as of end of period)	10	12	10
Revenues	$ 393,797	$ 327,983	$ 144,778
Operating expenses	169,418	147,899	59,593
Impairment of goodwill		150,886	
Impairment of property and equipment	26,882		
Depreciation and amortization expense	63,808	37,865	15,513
General and administrative expenses	35,694	2,980	1,863
Operating income (loss)	$ 97,995	$ (11,647)	$ 67,809
Inland:			
Number of barges (as of end of period)	17	27	27
Revenues	$ 19,794	$ 162,487	$ 107,100
Operating expenses	44,593	125,656	56,636
Impairment of goodwill		205,474	
Impairment of property and equipment		202,055	
Depreciation and amortization expense	32,465	43,107	16,264
General and administrative expenses	1,831	8,347	533
Operating income (loss)	$ (59,095)	$ (422,152)	$ 33,667
Domestic Liftboats:			
Number of liftboats (as of end of period)	41	45	47
Revenues	$ 75,584	$ 94,755	$ 137,745
Operating expenses	48,738	54,474	59,902
Depreciation and amortization expense	20,267	21,317	24,969
General and administrative expenses	2,039	2,386	2,190
Operating income	$ 4,540	$ 16,578	$ 50,684

International Liftboats:						
Number of liftboats (as of end of period)		24		20		18
Revenues	$	88,537	$	85,896	$	63,282
Operating expenses		48,240		39,122		31,879
Depreciation and amortization expense		12,880		9,912		7,619
General and administrative expenses		4,990		5,990		3,888
Operating income	$	22,427	$	30,872	$	19,896

Table of Contents

	Year Ended December 31, 2009	2008	2007
	(Dollars in thousands)		
Delta Towing:			
Revenues	$ 24,250	$ 58,328	$ 31,921
Operating expenses	27,674	36,676	16,050
Impairment of goodwill		86,733	
Depreciation and amortization expense	7,917	10,926	4,598
General and administrative expenses	1,336	4,058	1,011
Operating income (loss)	$ (12,677)	$ (80,065)	$ 10,262
Total Company:			
Revenues	$ 742,851	$ 1,111,807	$ 726,278
Operating expenses	514,136	631,711	346,191
Impairment of goodwill		950,287	
Impairment of property and equipment	26,882	376,668	
Depreciation and amortization expense	201,421	192,894	104,634
General and administrative expenses	92,558	81,160	49,811
Operating income (loss)	(92,146)	(1,120,913)	225,642
Interest expense	(77,986)	(63,778)	(34,859)
Expense of credit agreement fees	(15,073)		
Gain (loss) on early retirment of debt	12,157	26,345	(2,182)
Other, net	3,967	3,315	6,483
Income (loss) before income taxes	(169,081)	(1,155,031)	195,084
Income tax benefit (provision)	78,932	73,161	(59,072)
Income (loss) from continuing operations	(90,149)	(1,081,870)	136,012
Income (loss) from discontinued operation, net of taxes	(1,585)	(1,520)	510
Net income (loss)	$ (91,734)	$ (1,083,390)	$ 136,522

The following table sets forth selected operational data by operating segment for the periods indicated:

	Year Ended December 31, 2009				
	Operating Days	Available Days	Utilization(1)	Average Revenue per Day(2)	Average Operating Expense per Day(3)
Domestic Offshore	2,676	4,544	58.9%	$ 52,649	$ 38,616
International Offshore	3,100	3,714	83.5%	127,031	45,616
Inland	651	1,578	41.3%	30,406	28,259

Domestic Liftboats	9,535	14,804	64.4%	7,927	3,292
International Liftboats	4,293	7,209	59.6%	20,624	6,692

Table of Contents

	Year Ended December 31, 2008				
	Operating Days	Available Days	Utilization(1)	Average Revenue per Day(2)	Average Operating Expense per Day(3)
Domestic Offshore	5,907	8,166	72.3%	$ 64,730	$ 27,906
International Offshore	2,753	3,005	91.6%	119,137	49,218
Inland	4,048	5,885	68.8%	40,140	21,352
Domestic Liftboats	10,343	15,785	65.5%	9,161	3,451
International Liftboats	5,028	6,501	77.3%	17,084	6,018

	Year Ended December 31, 2007				
	Operating Days	Available Days	Utilization(1)	Average Revenue per Day(2)	Average Operating Expense per Day(3)
Domestic Offshore	3,265	4,958	65.9%	$ 73,952	$ 24,633
International Offshore	1,549	1,625	95.3%	93,465	36,673
Inland	2,279	2,941	77.5%	46,994	19,257
Domestic Liftboats	11,265	16,749	67.3%	12,228	3,576
International Liftboats	5,077	6,149	82.6%	12,464	5,184

(1) Utilization is defined as the total number of days our rigs or liftboats, as applicable, were under contract, known as operating days, in the period as a percentage of the total number of available days in the period. Days during which our rigs and liftboats were undergoing major refurbishments, upgrades or construction, and days during which our rigs and liftboats are cold-stacked, are not counted as available days. Days during which our liftboats are in the shipyard undergoing drydocking or inspection are considered available days for the purposes of calculating utilization.

(2) Average revenue per rig or liftboat per day is defined as revenue earned by our rigs or liftboats, as applicable, in the period divided by the total number of operating days for our rigs or liftboats, as applicable, in the period. Included in Domestic Offshore revenue is a total of $0.4 million related to amortization of contract specific capital expenditures reimbursed by the customer for the year ended December 31, 2007. There was no such revenue in the years ended December 31, 2009 and 2008. Included in International Offshore revenue is a total of $16.3 million, $11.6 million and $3.2 million related to amortization of deferred mobilization revenue and contract specific capital expenditures reimbursed by the customer for the years ended December 31, 2009, 2008 and 2007, respectively. Included in International Liftboats revenue is a total of $0.2 million and $0.3 million related to amortization of deferred mobilization revenue for the years ended December 31, 2009 and 2008, respectively. There was no such revenue in the year ended December 31, 2007.

(3) Average operating expense per rig or liftboat per day is defined as operating expenses, excluding depreciation and amortization, incurred by our rigs or liftboats, as applicable, in the period divided by the total number of available days in the period. We use available days to calculate average operating expense per rig or liftboat per day rather than operating days, which are used to calculate average revenue per rig or liftboat per day, because

we incur operating expenses on our rigs and liftboats even when they are not under contract and earning a dayrate. In addition, the operating expenses we incur on our rigs and liftboats per day when they are not under contract are typically lower than the per-day expenses we incur when they are under contract. Included in International Offshore operating expense is a total of $6.3 million, $5.6 million and $2.8 million related to amortization of deferred mobilization expenses for the years ended December 31, 2009, 2008 and 2007, respectively. Included in the International Offshore 2009 amortization is a $2.6 million charge to impair the deferred mobilization costs related to one international contract. Included in International Liftboats operating expense is a total of $0.2 million related to amortization of deferred mobilization expenses for the year ended December 31, 2009. There was no such operating expense in the years ended December 31, 2008 and 2007, respectively.

Our domestic liftboat operations generally are affected by the seasonal weather patterns in the U.S. Gulf of Mexico. These seasonal patterns may result in increased operations in the spring, summer and fall periods and a decrease in the winter months. The rainy weather, tropical storms, hurricanes and other storms prevalent in the U.S. Gulf of Mexico during the year affect our domestic liftboat operations. During such severe storms, our liftboats typically leave location and cease to earn a full dayrate. Under U.S. Coast Guard guidelines, the liftboats cannot return to work until the weather improves and seas are less than five feet. Demand for our domestic rigs may decline during hurricane season as our customers may reduce drilling activity. Accordingly, our operating results may vary from quarter to quarter, depending on factors outside of our control.

2009 Compared to 2008

Revenues

Consolidated. Total revenues for 2009 were $742.9 million compared with $1,111.8 million for 2008, a decrease of $369.0 million, or 33.2%. This decrease is further described below.

Domestic Offshore. Revenues for our Domestic Offshore segment were $140.9 million for 2009 compared with $382.4 million for 2008, a decrease of $241.5 million, or 63.2%. This decline resulted from decreased operating days from 5,907 in 2008 to 2,676 in 2009 primarily due to an overall decrease in demand and our cold stacking of rigs, which contributed $170.1 million of the decrease, and lower average dayrates which contributed $71.4 million of the decrease. Average utilization was 58.9% in 2009 compared with 72.3% in 2008.

International Offshore. Revenues for our International Offshore segment were $393.8 million for 2009 compared with $328.0 million for 2008, an increase of $65.8 million, or 20.1%. Approximately $154 million of this increase was due to increased operating days as a result of the commencement of the *Hercules 260* in late April 2008, *Hercules 258* in June 2008, *Hercules 208* in August 2008, *Hercules 261* in December 2008 and *Hercules 262* in January 2009. These favorable increases were partially offset by a decrease of approximately $76 million related to the *Hercules 156* and *Hercules 170* being in warm stack, *Hercules 206* being transferred to Domestic Offshore for cold stack in the fourth quarter of 2009 and *Hercules 110* in cold stack during the 2009 until the date of sale, and a lower average dayrate realized on *Hercules 205*. In addition, the *Hercules 185* contributed to an approximately $14 million decrease as it was in the shipyard for an upgrade for a portion of the Current Period. Average revenue per rig per day increased to $127,031 in 2009 from $119,137 in 2008 due primarily to higher average dayrates earned on *Hercules 261* and *Hercules 208* for a more significant portion of 2009 as well as the commencement of the *Hercules 262* in January 2009, partially offset by lower average dayrates earned on *Hercules 205* and *Hercules 206,* and *Hercules 156* in warm stack a majority of the year as well as *Hercules 185* which operated at a higher dayrate, but for fewer operating days.

Inland. Revenues for our Inland segment were $19.8 million for 2009 compared with $162.5 million for the 2008, a decrease of $142.7 million, or 87.8% as a result of an industry-wide decline in drilling in the transition zones. This decrease resulted primarily from decreased operating days, 651 in 2009 compared to 4,048 in 2008, an 83.9% decrease. Available days declined 73.2% during 2009 as compared to 2008 due to our cold stacking plan. Furthermore, average utilization was 41.3% on fewer available days in 2009 compared with 68.8% in 2008 as demand in the segment declined.

Domestic Liftboats. Revenues for our Domestic Liftboats segment were $75.6 million for 2009 compared with $94.8 million in 2008, a decrease of $19.2 million, or 20.2%. This decrease resulted primarily from lower average dayrates, which contributed $12.8 million of the decrease, as well as a $6.4 million decrease due to fewer operating days in 2009. Average revenue per vessel per day was $7,927 in 2009 compared with $9,161 in 2008, a decrease of $1,234 per day due primarily to lower dayrates in all vessel classes with a slight decrease due to mix of vessel class.

International Liftboats. Revenues for our International Liftboats segment were $88.5 million for 2009 compared with $85.9 million in 2008, an increase of $2.6 million, or 3.1%. This increase resulted from higher average dayrates, which contributed $17.8 million of the increase, significantly offset by fewer operating days, which contributed a $15.2 million decrease. The higher average dayrate was due to increased operating days on our larger class vessels, which have higher dayrates and lower utilization on the smaller class vessels which have lower dayrates.

Delta Towing. Revenues for our Delta Towing segment were $24.3 million for 2009 compared with $58.3 million for the 2008, a decrease of $34.1 million, or 58.4%, due to decreased activity both offshore and in the transition zone.

Operating Expenses

Consolidated. Total operating expenses for 2009 were $514.1 million compared with $631.7 million in 2008, a decrease of $117.6 million, or 18.6%. This decrease is further described below.

Domestic Offshore. Operating expenses for our Domestic Offshore segment were $175.5 million in 2009 compared with $227.9 million in 2008, a decrease of $52.4 million, or 23.0%. The decrease was driven primarily by lower labor, catering, repairs and maintenance, and insurance expenses primarily as a result of our cold stacking of rigs. Available days decreased to 4,544 in 2009 from 8,166 in 2008 due to our cold stacking of rigs. Average operating expenses per rig per day were $38,616 in 2009 compared with $27,906 in 2008 due in part to shore based support and cold stacked rig costs being allocated over fewer available days.

International Offshore. Operating expenses for our International Offshore segment were $169.4 million in 2009 compared with $147.9 million in 2008, an increase of $21.5 million, or 14.5%. Available days increased to 3,714 in 2009 from 3,005 in 2008. Average operating expenses per rig per day were $45,616 in 2009 compared with $49,218 in 2008. This decrease related primarily to the *Hercules 156* and *Hercules 170* being in warm stack during a portion of 2009 and the initial start-up costs incurred during 2008 related to our India and Malaysia operations, partially offset by an increase due to the commencement of *Hercules 261* and *Hercules 262* in December 2008 and January 2009, respectively.

Inland. Operating expenses for our Inland segment were $44.6 million in 2009 compared with $125.7 million in 2008, a decrease of $81.1 million, or 64.5%. By mid 2009, fourteen of our seventeen barges were cold stacked which significantly reduced the segment s variable operating costs. Average operating expenses per rig per day were $28,259 in 2009 compared with $21,352 in 2008. The increase in cost per day was driven primarily by costs associated with shore based support and cold stacked barges being allocated over fewer available days.

Domestic Liftboats. Operating expenses for our Domestic Liftboats segment were $48.7 million in 2009 compared with $54.5 million in 2008, a decrease of $5.7 million, or 10.5% due primarily to lower labor expense, fuel and oil and insurance costs. Available days decreased to 14,804 in 2009 from 15,785 in 2008 due to four vessels that were transferred to our International Liftboats Segment, these four vessels were not marketed during the third quarter 2009 in preparation of their mobilization to our International Liftboats Segment in the fourth quarter of 2009, and due to the cold stacking of several liftboats during 2009 that were available in 2008. Average operating expenses per vessel per day had a slight decrease to $3,292 per day during 2009 from $3,451 per day during 2008.

International Liftboats. Operating expenses for our International Liftboats segment were $48.2 million for 2009 compared with $39.1 million in 2008, an increase of $9.1 million, or 23.3%. Available days increased to 7,209 in 2009 from 6,501 in 2008 largely related to the current year availability of the *Whale Shark* and *Amberjack*, which were transferred to our International Liftboats segment from the Domestic Liftboats segment during 2008. Average operating expenses per liftboat per day were $6,692 in 2009 compared with $6,018 in 2008 due to higher repairs and maintenance expenses and costs associated with transferring and preparing the four domestic vessels to work in West Africa.

Delta Towing. Operating expenses for our Delta Towing segment were $27.7 million in 2009 compared with $36.7 million in 2008, a decrease of $9.0 million, or 24.5%. Due to the decline in activity in both offshore and the transition zone, we cold stacked certain assets in our fleet which resulted in lower labor, repairs and maintenance and fuel and oil expenses during 2009.

Table of Contents

Impairment of Property and Equipment

Impairment of Property and Equipment in 2009 was $26.9 million compared with $376.7 million in 2008. The 2008 impairment charges of $376.7 million related to certain property and equipment on our Domestic Offshore and Inland segments in 2008. In June 2009, we entered into an agreement to sell *Hercules 110*, which was cold stacked in Trinidad, and incurred a $26.9 million impairment charge to write-down the rig to its fair value less costs to sell.

Depreciation and Amortization

Depreciation and amortization expense in 2009 was $201.4 million compared with $192.9 million in 2008, an increase of $8.5 million, or 4.4%. This increase resulted primarily from additional depreciation related to the commencement of *Hercules 260* in late April 2008, *Hercules 350* in June 2008, *Hercules 208* in August 2008, *Hercules 261* in December 2008 and *Hercules 262* in January 2009. These increases are partially offset by reduced depreciation due to the impairment of certain rigs, barges and related equipment in the fourth quarter of 2008 and lower amortization of our international contract values.

General and Administrative Expenses

General and administrative expenses in 2009 were $92.6 million compared with $81.2 million in 2008, an increase of $11.4 million, or 14.0%. This increase relates primarily to an allowance for doubtful accounts receivable of $30.8 million, net, of which approximately $26.8 million as of December 31, 2009, related to a customer in its International Offshore segment, partially offset by the cost reduction initiatives implemented in late 2008 and in 2009 in response to the significant decline in activity in several of our business segments. In addition, 2008 included $7.5 million in executive severance related costs.

Interest Expense

Interest expense increased $14.2 million, or 22.3%. This increase was primarily related to the higher interest capitalized in 2008 and interest expense incurred on our 10.5% Senior Secured Notes issued in October 2009. In addition, the increase in interest rates after the Credit Amendment were offset by lower debt balances due to the early retirement of a portion of our term loan.

Expense of Credit Agreement Fees

During 2009, we amended our Credit Agreement and repaid and terminated a portion of our credit facility. In doing so, we recorded the write-off of certain deferred debt issuance costs and certain fees directly related to these activities totaling $15.1 million.

Gain (Loss) on Early Retirement of Debt, Net

Gain on early retirement of debt, net was $12.2 million in 2009 compared with $26.3 million in 2008, a decrease of $14.2 million or 53.9%. During 2009, we retired a portion of our term loan facility and wrote off $1.6 million in associated unamortized issuance costs. In addition, in 2009 we retired $65.8 million aggregate principal amount of the 3.375% Convertible Senior Notes for cash and equity consideration of approximately $40.1 million, resulting in a gain of $13.7 million, net of an associated write-off of a portion of our unamortized issuance costs. In 2008, the gain on early retirement of debt in the amount of $26.3 million related to the December 2008 redemption of $73.2 million accreted principal amount ($88.2 million aggregate principal amount) of the 3.375% Convertible Senior Notes for a cost of $44.8 million, net of the related write off of $2.1 million of unamortized issuance costs.

Other Income

Other income in 2009 was $4.0 million compared with $3.3 million in 2008, an increase of $0.7 million or 19.7%. This increase is primarily due to foreign currency exchange gains, partially offset by lower interest income.

Table of Contents

Income Tax Benefit

Income tax benefit was $78.9 million on pre-tax loss of $169.1 million during 2009, compared to a benefit of $73.2 million on pre-tax loss of $1,155.0 million for 2008. The effective tax rate changed to a tax benefit of 46.7% in 2009 from a tax benefit of 6.3% in 2008. The change in the effective tax rate is due to the non-deductible goodwill impairment in 2008 as well as a state tax benefit of $14.1 million based on prior year state tax audits concluded in the fourth quarter of 2009 and a federal tax benefit of $2.5 million based on recent court cases related to alternative minimum tax positions.

2008 Compared to 2007

Revenues

Consolidated. Total revenues for 2008 were $1,111.8 million compared with $726.3 million for 2007, an increase of $385.5 million, or 53%. This increase resulted primarily from revenues generated from assets acquired from TODCO (Acquired Assets) in July 2007. Total revenues included $15.6 million in reimbursements from our customers for expenses paid by us in 2008 compared with $15.2 million in 2007.

Domestic Offshore. Revenues for our Domestic Offshore segment were $382.4 million for 2008 compared with $241.5 million for 2007, an increase of $140.9 million, or 58%. Revenues for 2008 include approximately $266.8 million compared to $119.4 million for 2007 from the Acquired Assets. Revenue increased $171.0 million due to additional operating days primarily from the Acquired Assets, partially offset by a $30.1 million decrease due to lower average dayrates. Average revenue per rig per day decreased to $64,730 in 2008 from $73,952 in 2007. Average utilization was 72.3% in 2008 compared with 65.9% in 2007. Revenues for our Domestic Offshore segment include $1.3 million and $2.4 million in reimbursements from our customers for expenses paid by us in 2008 and 2007, respectively.

International Offshore. Revenues for our International Offshore segment were $328.0 million for 2008 compared with $144.8 million for 2007, an increase of $183.2 million, or 127%. Revenues for 2008 include approximately $124.5 million compared to $65.1 million for 2007 from the Acquired Assets. Revenue increased $143.4 million due to additional operating days primarily from the Acquired Assets and $39.8 million due to higher average dayrates. Average revenue per rig per day was $119,137 in 2008 compared with $93,465 in 2007 as a result of the commencement of *Hercules 260* and the associated revenue from the provision of marine services, and certain rigs operating at higher dayrates in 2008. Included in our revenues for the International Offshore segment is a total of $11.6 million and $3.2 million related to amortization of deferred mobilization revenue and contract specific capital expenditures reimbursed by the customer for 2008 and 2007, respectively. In addition, revenues for our International Offshore segment included $1.0 million and $1.5 million in reimbursements from our customers for expenses paid by us in 2008 and 2007, respectively.

Inland. Revenues for our Inland segment were $162.5 million for 2008 compared with $107.1 million for the 2007, an increase of $55.4 million, or 52%. The 2007 revenue is for the period from July 11, 2007 to December 31, 2007 as we did not have an Inland segment prior to the TODCO acquisition. Average dayrates and average utilization in 2008 declined to $40,140 and 68.8% from $46,994 and 77.5% in 2007, respectively. Lower revenue per day also reflects our customers lower drilling activity. Revenues for our Inland segment include $1.5 million and $0.7 million in reimbursements from our customers for expenses paid by us in 2008 and 2007, respectively.

Domestic Liftboats. Revenues for our Domestic Liftboats segment were $94.8 million for 2008 compared with $137.7 million in 2007, a decrease of $43.0 million, or 31%. This decrease resulted primarily from lower average dayrates, which contributed $34.5 million of the decrease, and fewer operating days, which contributed $8.5 million of the decrease. Operating days decreased to 10,343 in 2008 from 11,265 in 2007 due primarily to lower customer activity in the Gulf of Mexico in 2008 as compared to the 2007. Average utilization also declined to 65.5% in 2008 from 67.3% in 2007. Average revenue per vessel per day was $9,161 in 2008 compared with $12,228 in 2007, a decrease of $3,067. Approximately $2,369 of the decrease in average revenue per vessel per day was due to lower dayrates and approximately $698 was due to

Table of Contents

mix of vessel class. Revenues for our Domestic Liftboats segment included $4.8 million in reimbursements from our customers for expenses paid by us in 2008 compared with $5.6 million in 2007.

International Liftboats. Revenues for our International Liftboats segment were $85.9 million for 2008 compared with $63.3 million in 2007, an increase of $22.6 million, or 36%. The increase resulted primarily from higher average dayrates, which contributed $23.5 million of the increase, partially offset by fewer operating days. Operating days decreased from 5,077 days in 2007 to 5,028 days in 2008. Average revenue per liftboat per day was $17,084 in 2008 compared with $12,464 in 2007, with average utilization of 77.3% in 2008 compared with 82.6% in 2007. Revenues for our International Liftboats segment included $6.3 million and $4.7 million in reimbursements from our customers for expenses paid by us in 2008 and 2007, respectively.

Delta Towing. Revenues for our Delta Towing segment were $58.3 million for 2008 compared with $31.9 million for the 2007, an increase of $26.4 million, or 83%. Prior to our acquisition of TODCO in July 2007, we did not have a Delta Towing segment.

Operating Expenses

Consolidated. Total operating expenses for 2008 were $631.7 million compared with $346.2 million in 2007, an increase of $285.5 million, or 82%. This increase is further described below.

Domestic Offshore. Operating expenses for our Domestic Offshore segment were $227.9 million in 2008 compared with $122.1 million in 2007, an increase of $105.8 million, or 87%. Operating expenses for 2008 include approximately $146.8 million associated with the Acquired Assets compared to approximately $67.9 million in 2007. Available days increased to 8,166 in 2008 from 4,958 in 2007. Average operating expenses per rig per day were $27,906 in 2008 compared with $24,633 in 2007. The increase was driven primarily by higher costs related to labor and repairs and maintenance, partially offset by lower insurance costs.

International Offshore. Operating expenses for our International Offshore segment were $147.9 million in 2008 compared with $59.6 million in 2007, an increase of $88.3 million, or 148%. Operating expenses for 2008 include approximately $19.9 million associated with the Acquired Assets compared to $30.2 million in 2007. Available days increased to 3,005 in 2008 from 1,625 in 2007. Average operating expenses per rig per day were $49,218 in 2008 compared with $36,673 in 2007. The increase resulted primarily from higher costs related to marine service equipment rentals, labor and additional amortization of deferred mobilization and contract preparation expenses. Included in operating expense is $5.6 million in amortization of deferred mobilization expense in 2008 compared with $2.8 million in 2007.

Inland. Operating expenses for our Inland segment were $125.7 million in 2008 compared with $56.6 million in 2007, an increase of $69.0 million, or 122%. Available days increased to 5,885 in 2008 from 2,941 in 2007 due to the full year of operations in 2008, partially offset by cold stacking additional barges in 2008. Average operating expenses per rig per day were $21,352 in 2008 compared with $19,257 in 2007. The increase was driven primarily by higher costs related to labor and fuel, partially offset by lower equipment rental costs. Prior to our acquisition of TODCO in July 2007, we did not have an Inland segment.

Domestic Liftboats. Operating expenses for our Domestic Liftboats segment were $54.5 million in 2008 compared with $59.9 million in 2007, a decrease of $5.4 million, or 9%. Available days decreased to 15,785 in 2008 from 16,749 in 2007. Average operating expenses per vessel per day were $3,451 in 2008 compared with $3,576 in 2007. The decrease was primarily due to lower repairs and maintenance and insurance costs.

International Liftboats. Operating expenses for our International Liftboats segment were $39.1 million for 2008 compared with $31.9 million in 2007, an increase of $7.2 million, or 23%. Average operating expenses per liftboat per day were $6,018 in 2008 compared with $5,184 in 2007. This increase was driven primarily by costs accrued for a payment to a former owner, as well as increased repairs and maintenance costs.

Delta Towing. Operating expenses for our Delta Towing segment were $36.7 million in 2008 compared with $16.1 million in 2007, an increase of $20.6 million, or 129% as we did not have a Delta Towing segment prior to our acquisition of TODCO in July 2007.

Impairment of Goodwill

In the year ended December 31, 2008, we incurred $950.3 million related to the impairment of our goodwill. There were no comparable charges in the year ended December 31, 2007.

Impairment of Property and Equipment

In the year ended December 31, 2008, we incurred $376.7 million of impairment charges related to certain property and equipment on our Domestic Offshore and Inland segments. There were no comparable charges in the year ended December 31, 2007.

Depreciation and Amortization

Depreciation and amortization expense in 2008 was $192.9 million compared with $104.6 million in 2007, an increase of $88.3 million, or 84%. This increase resulted partially from the full year depreciation related to the Acquired Assets. Depreciation related to Acquired Assets was approximately $135.9 million for 2008 compared to approximately $52.1 million in 2007.

General and Administrative Expenses

General and administrative expenses in 2008 were $81.2 million compared with $49.8 million in 2007, an increase of $31.3 million, or 63%. The increase is primarily related to incurring the full year incremental general and administrative costs associated with the Acquired Assets in 2008, a provision for doubtful accounts receivable of $6.2 million, as well as $7.5 million in executive severance related costs.

Interest Expense

Interest expense increased $28.9 million, or 83%. The increase was primarily due to interest on our borrowings under our 2007 senior secured term loan and interest on our 3.375% Convertible Senior Notes issued in June 2008, including amortization of the original issue discount related to the 3.375% Convertible Senior Notes.

Gain (Loss) on Early Retirement of Debt, Net

In 2008, the gain on early retirement of debt in the amount of $26.3 million related to the December 2008, redemption of $73.2 million accreted principal amount ($88.2 million aggregate principal amount) of the 3.375% Convertible Senior Notes for a cost of $44.8 million which resulted in a gain of $28.4 million and the related write off of $2.1 million of unamortized issuance costs. In 2007, the loss on early retirement of debt in the amount of $2.2 million related to the write off of deferred financing fees in connection with repayment of term loan principal in April and July 2007.

Other Income

Other income in 2008 was $3.3 million compared with $6.5 million in 2007, a decrease of $3.2 million or 49%. This decrease is primarily due to lower interest income due to lower cash balances in 2008.

Income Tax Benefit (Provision)

Income tax benefit was $73.2 million on pre-tax loss of $1,155.0 million during 2008, compared to a provision of $59.1 million on pre-tax income of $195.1 million for 2007. The effective tax rate decreased to a tax benefit of 6.3% in 2008 from a tax provision of 30.3% in 2007. The decrease in the effective tax rate primarily reflects the impact of the non-deductible goodwill impairment.

Table of Contents

Discontinued Operation

We had a loss from discontinued operation, net of taxes of $1.5 million in 2008 compared to income from discontinued operation, net of taxes of $0.5 million in 2007. The 2008 loss includes the impact of the wind down costs associated with our land rigs sold in December 2007.

Non-GAAP Financial Measures

Regulation G, *General Rules Regarding Disclosure of Non-GAAP Financial Measures* and other SEC regulations define and prescribe the conditions for use of certain Non-Generally Accepted Accounting Principles (Non-GAAP) financial measures. We use various Non-GAAP financial measures such as adjusted operating income (loss), adjusted income (loss) from continuing operations, adjusted diluted earnings (loss) per share from continuing operations, EBITDA and Adjusted EBITDA. EBITDA is defined as net income plus interest expense, income taxes, depreciation and amortization. We believe that in addition to GAAP based financial information, Non-GAAP amounts are meaningful disclosures for the following reasons: (i) each are components of the measures used by our board of directors and management team to evaluate and analyze our operating performance and historical trends, (ii) each are components of the measures used by our management team to make day-to-day operating decisions, (iii) the Credit Agreement contains covenants that require us to maintain a total leverage ratio and a consolidated fixed charge coverage ratio, which contain Non-GAAP adjustments as components, (iv) each are components of the measures used by our management to facilitate internal comparisons to competitors results and the shallow-water drilling and marine services industry in general, (v) results excluding certain costs and expenses provide useful information for the understanding of the ongoing operations without the impact of significant special items, and (vi) the payment of certain bonuses to members of our management is contingent upon, among other things, the satisfaction by the Company of financial targets, which may contain Non-GAAP measures as components. We acknowledge that there are limitations when using Non-GAAP measures. The measures below are not recognized terms under GAAP and do not purport to be an alternative to net income as a measure of operating performance or to cash flows from operating activities as a measure of liquidity. EBITDA and Adjusted EBITDA are not intended to be a measure of free cash flow for management s discretionary use, as it does not consider certain cash requirements such as tax payments and debt service requirements. In addition, the EBITDA and Adjusted EBITDA amounts presented in the following table should not be used for covenant compliance purposes as these amounts could differ materially from the amounts ultimately calculated under our Credit Agreement. Because all companies do not use identical calculations, the amounts below may not be comparable to other similarly titled measures of other companies.

The following tables present a reconciliation of the GAAP financial measures to the corresponding adjusted financial measures (in thousands, except per share amounts):

	For the Years Ended December 31, 2009	2008	2007
Operating Income (Loss)	$ (92,146)	$ (1,120,913)	$ 225,642
Adjustments:			
Property and equipment impairment	26,882	376,668	
Goodwill impairment		950,287	
Executive separation and benefit related charges		7,468	3,090
Total adjustments	26,882	1,334,423	3,090
Adjusted Operating Income (Loss)	$ (65,264)	$ 213,510	$ 228,732
Income (Loss) from Continuing Operations	$ (90,149)	$ (1,081,870)	$ 136,012
Adjustments:			
Property and equipment impairment	26,882	376,668	
Goodwill impairment		950,287	
Executive separation and benefit related charges		7,468	3,090
(Gain) loss on early retirement of debt, net	(12,157)	(26,345)	1,524
Expense of credit agreement fees	15,073		
Tax impact of adjustments	(14,799)	(133,331)	(1,615)
Total adjustments	14,999	1,174,747	2,999
Adjusted Income (Loss) from Continuing Operations	$ (75,150)	$ 92,877	$ 139,011
Diluted Earnings (Loss) per Share from Continuing Operations	$ (0.93)	$ (12.25)	$ 2.28
Adjustments:			
Property and equipment impairment	0.28	4.26	
Goodwill impairment		10.76	
Executive separation and benefit related charges		0.08	0.05
(Gain) loss on early retirement of debt, net	(0.13)	(0.30)	0.03
Expense of credit agreement fees	0.16		
Tax impact of adjustments	(0.15)	(1.51)	(0.03)
Total adjustments	0.16	13.29	0.05
Adjusted Diluted Earnings (Loss) per Share from Continuing Operations	$ (0.77)	$ 1.04	$ 2.33
Income (Loss) from Continuing Operations	$ (90,149)	$ (1,081,870)	$ 136,012
Interest expense	77,986	63,778	34,859
Income tax (benefit) provision	(78,932)	(73,161)	59,072
Depreciation and amortization	201,421	192,894	104,634

EBITDA	110,326	(898,359)	334,577
Adjustments:			
Property and equipment impairment	26,882	376,668	
Goodwill impairment		950,287	
Executive separation and benefit related charges		7,468	3,090
(Gain) loss on early retirement of debt, net	(12,157)	(26,345)	1,524
Expense of credit agreement fees	15,073		
Total adjustments	29,798	1,308,078	4,614
Adjusted EBITDA	$ 140,124	$ 409,719	$ 339,191

Critical Accounting Policies

Critical accounting policies are those that are important to our results of operations, financial condition and cash flows and require management s most difficult, subjective or complex judgments. Different amounts would be reported under alternative assumptions. We have evaluated the accounting policies used in the preparation of the consolidated financial statements and related notes appearing elsewhere in this annual report. We apply those accounting policies that we believe best reflect the underlying business and economic events, consistent with accounting principles generally accepted in the United States. We believe that our policies are generally consistent with those used by other companies in our industry. We base our estimates on historical experience and on various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results could differ from those estimates.

We periodically update the estimates used in the preparation of the financial statements based on our latest assessment of the current and projected business and general economic environment. During recent periods, there has been substantial volatility and a decline in commodity prices. In addition, there has been uncertainty in the capital markets and available financing has been limited. These conditions adversely impact the business of our customers, and in turn our business. This could result in changes to estimates used in preparing our financial statements, including the assessment of certain of our assets for impairment. Our significant accounting policies are summarized in Note 1 to our consolidated financial statements. We believe that our more critical accounting policies include those related to property and equipment, revenue recognition, income tax, allowance for doubtful accounts, deferred charges, stock-based compensation, cash and cash equivalents and intangible assets. Inherent in such policies are certain key assumptions and estimates.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand, demand deposits with banks and all highly liquid investments with original maturities of three months or less.

Other Intangible Assets

In connection with the acquisition of TODCO, we allocated $17.6 million in value to certain international customer contracts. These amounts are being amortized over the life of the contracts. As of December 31, 2009, the customer contracts had a carrying value of $2.2 million, net of accumulated amortization of $15.4 million, and are included in Other Assets, Net on the Consolidated Balance Sheets.

Amortization expense was $5.0 million, $7.6 million and $2.8 million for the years ended December 31, 2009, 2008 and 2007, respectively. Future estimated amortization expense for the carrying amount of intangible assets as of December 31, 2009 is expected to be $1.6 million in 2010 and $0.6 million in 2011.

Property and Equipment

Property and equipment represents 84.5% of our total assets as of December 31, 2009. Property and equipment is stated at cost, less accumulated depreciation. Expenditures that substantially increase the useful lives of our assets are capitalized and depreciated, while routine expenditures for repairs and maintenance items are expensed as incurred, except for expenditures for drydocking our liftboats. Drydock costs are capitalized at cost as Other Assets, Net on the Consolidated Balance Sheets and amortized on the straight-line method over a period of 12 months (see Deferred Charges). Depreciation is computed using the straight-line method, after allowing for salvage value where applicable, over the useful life of the asset, which is typically 15 years for our rigs and liftboats. We review our property and equipment for potential impairment when events or changes in circumstances indicate that the carrying value of any asset may not be recoverable or when reclassifications are made between property and equipment and assets held for sale. Factors that might indicate a potential impairment may include, but are not limited to, significant decreases in the market value of the long-lived asset, a significant change in the long-lived asset s physical condition, a change in industry conditions or a substantial reduction in cash flows associated with the use of the long-lived asset. For property and equipment held for use, the determination of recoverability is made based on the estimated undiscounted future net cash flows of the related asset or group of assets being reviewed. Any actual impairment charge would be recorded using the estimated discounted value of future cash flows. This evaluation requires us to make judgments regarding long-term forecasts of future revenues and costs. In turn these forecasts are uncertain in that they require assumptions about demand for our services, future market conditions and technological developments. Significant and unanticipated changes to these assumptions could require a provision for impairment in a future period. Given the nature of these evaluations and their application to specific asset groups and specific times, it is not possible to reasonably quantify the impact of changes in these assumptions.

Supply and demand are the key drivers of rig and vessel utilization and our ability to contract our rigs and vessels at economical rates. During periods of an oversupply, it is not uncommon for us to have rigs or vessels idled for extended periods of time, which could indicate that an asset group may be impaired. Our rigs and vessels are mobile units, equipped to operate in geographic regions throughout the world and, consequently, we may move rigs and vessels from an oversupplied region to one that is more lucrative and undersupplied when it is economical to do so. As such, our rigs and vessels are considered to be interchangeable within classes or asset groups and accordingly, we perform our impairment evaluation by asset group.

Our estimates, assumptions and judgments used in the application of our property and equipment accounting policies reflect both historical experience and expectations regarding future industry conditions and operations. Using different estimates, assumptions and judgments, especially those involving the useful lives of our rigs and liftboats and expectations regarding future industry conditions and operations, would result in different carrying values of assets and results of operations. For example, a prolonged downturn in the drilling industry in which utilization and dayrates were significantly reduced could result in an impairment of the carrying value of our assets.

Useful lives of rigs and vessels are difficult to estimate due to a variety of factors, including technological advances that impact the methods or cost of oil and gas exploration and development, changes in market or economic conditions and changes in laws or regulations affecting the drilling industry. We evaluate the remaining useful lives of our rigs and vessels when certain events occur that directly impact our assessment of the remaining useful lives of the rigs and vessels and include changes in operating condition, functional capability and market and economic factors. We also consider major capital upgrades required to perform certain contracts and the long-term impact of those upgrades on the future marketability when assessing the useful lives of individual rigs and vessels.

During the fourth quarter 2008, demand for our domestic drilling assets declined dramatically, significantly beyond our expectations. Demand in these segments is driven by underlying commodity prices which fell to levels lower than those seen in several years. The deterioration in these industry conditions in the fourth quarter negatively impacted our outlook for 2009 and we responded by cold stacking several additional rigs in 2009. We considered these factors and our change in our outlook as an indicator of impairment and assessed the rig assets of the Inland and Domestic Offshore segments for impairment. When analyzing our assets for impairment, we separate our marketable rigs, those rigs that are actively marketed and can be warm stacked or cold stacked for short periods of time depending on market conditions, from our non-marketable rigs, those rigs that have been cold stacked for an extended period of time or those rigs that we do not reasonably expect to market in the foreseeable future. Based on an undiscounted cash flow analysis, it was determined that the non-marketable rigs for both segments were impaired and we recorded an impairment charge of $376.7 million for the year ended December 31, 2008. In addition, we analyzed our other segments for impairment as of December 31, 2008 and noted that each segment had adequate undiscounted cash flows to recover their property and equipment carrying values. In 2009 we entered into an agreement to sell *Hercules 110* and we realized approximately $26.9 million ($13.1 million, net of tax) of impairment charges related to the write-down of the rig to fair value less costs to sell during the second quarter of 2009. The sale was completed in August 2009. There were no impairment charges for the year ended December 31, 2007.

Revenue Recognition

Revenues generated from our contracts are recognized as services are performed, as long as collectability is reasonably assured. Some of our contracts also allow us to recover additional direct costs, including mobilization and demobilization costs, additional labor and additional catering costs. Additionally, some of our contracts allow us to receive fees for contract specific capital improvements to a rig. Under most of our liftboat contracts, we receive a variable rate for reimbursement of costs such as catering, fuel, oil, rental equipment, crane overtime and other items. Revenue for the recovery or reimbursement of these costs is recognized when the costs are incurred except for mobilization revenues and reimbursement for contract specific capital expenditures, which are recognized as services are performed over the term of the related contract.

Income Taxes

Our provision for income taxes takes into account the differences between the financial statement treatment and tax treatment of certain transactions. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates is recognized as income or expense in the period that includes the enactment date.

Our net income tax expense or benefit is determined based on the mix of domestic and international pre-tax earnings or losses, respectively, as well as the tax jurisdictions in which we operate. We operate in multiple countries through various legal entities. As a result, we are subject to numerous domestic and foreign tax jurisdictions and are taxed on various bases: income before tax, deemed profits (which is generally determined using a percentage of revenue rather than profits), and withholding taxes based on revenue. The calculation of our tax liabilities involves consideration of uncertainties in the application and interpretation of complex tax regulations in our operating jurisdictions. Changes in tax laws, regulations, agreements and treaties, or our level of operations or profitability in each taxing jurisdiction could have an impact upon the amount of income taxes that we provide during any given year.

In March 2007, one of our subsidiaries received an assessment from the Mexican tax authorities related to our operations for the 2004 tax year. This assessment contests our right to certain deductions and also claims the subsidiary did not remit withholding tax due on certain of these deductions. We are pursuing our alternatives to resolve this assessment.

Certain of our international rigs are owned or operated, directly or indirectly, by our wholly owned Cayman Islands subsidiaries. Most of the earnings from these subsidiaries are reinvested internationally and remittance to the United States is indefinitely postponed. We recognized $1.1 million of deferred U.S. tax expense on foreign earnings which management expects to repatriate in the future.

Allowance for Doubtful Accounts

Accounts receivable represents approximately 5.9% of our total assets and 41.6% of our current assets as of December 31, 2009. We continuously monitor our accounts receivable from our customers to identify any collectability issues. An allowance for doubtful accounts is established based on reviews of individual customer accounts, recent loss experience, current economic conditions and other pertinent factors. Accounts deemed uncollectable are charged to the allowance. We establish an allowance for doubtful accounts based on the actual amount we believe is not collectable. As of December 31, 2009 and 2008, there was $38.5 million and $7.8 million in allowance for doubtful accounts, respectively. During 2009, we increased our allowance for doubtful accounts by a net $30.8 million, of which $26.8 million related to a single customer operating one rig in our International Offshore segment.

Deferred Charges

All of our U.S. flagged liftboats are required to undergo regulatory inspections on an annual basis and to be drydocked two times every five years to ensure compliance with U.S. Coast Guard regulations for vessel safety and vessel maintenance standards. Costs associated with these inspections, which generally involve setting the vessels on a drydock, are deferred, and the costs are amortized over a period of 12 months. As of December 31, 2009 and 2008, our net deferred charges related to regulatory inspection costs totaled $4.8 million and $5.4 million, respectively. The amortization of the regulatory inspection costs was reported as part of our depreciation and amortization expense.

Stock-Based Compensation

We recognize compensation cost for all share-based payments awarded in accordance with Financial Accounting Standards Board (FASB) Codification Topic 718, *Compensation Stock Compensation* and in accordance with such we record the grant date fair value of share-based payments awarded as compensation expense using a straight-line method over the service period. The fair value of our restricted stock grants is based on the closing price of our common stock on the date of grant. Our estimate of compensation expense requires a number of complex and subjective assumptions and changes to those assumptions could result in different valuations for individual share awards. We estimate the fair value of the options granted using the Trinomial Lattice option pricing model using the following assumptions: expected dividend yield, expected stock price volatility, risk-free interest rate and employee exercise patterns (expected life of the options). We also estimate future forfeitures and related tax effects.

We are estimating that the cost relating to stock options granted through December 31, 2009 will be $3.5 million over the remaining vesting period of 1.8 years and the cost relating to restricted shares granted through December 31, 2009 will be $4.4 million over the remaining vesting period of 0.8 years; however, due to the uncertainty of the level of share-based payments to be granted in the future, these amounts are estimates and subject to change.

OUTLOOK

Offshore

In general, demand for our drilling rigs is a function of our customers capital spending plans, which are largely driven by current commodity prices and their expectations of future commodity prices. Demand in the U.S. Gulf of Mexico is particularly driven by natural gas prices, with demand internationally typically driven by oil prices.

U.S. natural gas prices tend to be highly volatile. Since mid-2008, the spot price for Henry Hub natural gas has ranged from a high of $13.31 per MMBtu in July 2008, to a low of $1.88 in September 2009. As of February 24, 2010, the spot price for Henry Hub natural gas was $4.91 per MMBtu, The twelve month strip, or the average of the next twelve month s futures contract, was $5.33 per MMBtu on February 24, 2010. A myriad of factors combined to cause natural gas prices to decline to extremely depressed levels during the late summer and fall of 2009 from its recent high in mid-2008. The worldwide economic downturn resulted in reduced energy consumption, creating a sharp decline in the demand for natural gas. On the supply side, increases in onshore production in the U.S., driven by a significant increase in onshore drilling activity through mid-2008 and increased activity in prolific unconventional natural gas basins also put downward pressure on natural gas prices. Growing deepwater production and potential increased deliveries of liquefied natural gas are additional factors which weighed on natural gas prices.

We believe the recovery in natural gas prices to recent levels has been driven by several factors, including the expectations for an economic rebound leading to a recovery in industrial demand for natural gas and the belief that the decline in North American drilling activity from its recent peak may lead to declines in production. All of these factors, together with weather, will likely remain key drivers in the natural gas market for the foreseeable future.

Oil prices also declined significantly from mid-2008 to early 2009 as a result of the anticipated effects of global economic weakness, increase in oil inventories relative to consumption and a strengthening in the U.S. dollar. The price of West Texas intermediate crude (WTI) declined from $145.29 as of July 3, 2008, to a multi-year low of $31.41 in December 2008. However, it has since recovered meaningfully to $79.75 as of February 24, 2010.

Many of our customers, particularly those focused in the U.S. Gulf of Mexico, significantly reduced their capital spending in 2009 relative to 2008 spending due to the substantial declines in commodity prices, the weak global economic outlook and poor capital market conditions during early 2009.

Based on 2010 capital spending surveys, we expect domestic focused exploration and production capital spending will increase in 2010. The expected higher level of capital spending, may lead to an increase in drilling activity in the shallow water U.S. Gulf of Mexico, however, activity levels will continue to be highly dependent upon natural gas prices, among other factors as our domestic focused customers often quickly adjust their drilling plans to changes in the outlook. Additionally, operators focused in the U.S., have increasingly been deploying incremental capital to other less mature basins such as the various shale formations, a trend that is expected to continue for the foreseeable future. Further, during 2009, we experienced an increase in seasonality with certain operators completing their drilling programs during the first half of the year, so as to avoid drilling during the Atlantic hurricane season. A continuation of this trend could be negative for our operating results as it would be difficult to adjust our cost structure to account for such seasonality.

While international spending programs are much longer-term in nature than typical U.S. drilling programs, and the customers tend to have greater financial resources, international capital spending also declined in 2009, following nine years of growth, but to a lesser degree. However, international focused capital spending is also expected to modestly increase during 2010.

While increased capital spending may lead to additional demand in both domestic and international regions, the offshore drilling industry is still expected to have excess capacity of jackup drilling rigs in 2010, given the current number of idle jackup rigs and expected growth in supply. As of February 24, 2010, there were a total of 79 jackup rigs in the U.S. Gulf of Mexico, with 39 contracted, 8 stacked ready, one en route and 31 in the shipyard or cold stacked. Cold stacked rigs are generally not marketed and in some cases would require significant capital to reactivate. Also as of February 24, 2010, there were 374 jackup rigs located in international markets, with 305 contracted, 34 stacked ready, 2 in port or on standby and 33 in the shipyard or cold stacked. Further, 60 new jackup rigs are either under construction or on order for delivery through 2012. Twenty-six of these are scheduled to be delivered during 2010. While we anticipate several of these orders may be delayed or cancelled, the majority of these will likely ultimately be delivered and compete with our fleet. As a result of generally higher dayrates, longer duration contracts and lower insurance costs which are prevalent internationally, among other factors, we believe the vast majority of the newbuild jackup rigs will target international regions rather than the U.S. Gulf of Mexico. Our ability to secure new contracts for our international fleet or to expand our international drilling operations may be limited by the increased supply of newbuild jackup rigs.

While potential increases in capital spending may lead to improving jackup rig demand in 2010, the expected newbuild deliveries, coupled with relatively large number of idle marketed jackup rigs, represent a significant amount of over capacity relative to current demand and may make it challenging for the industry to see any meaningful improvement in dayrates.

Nonetheless, a number of factors give us optimism for the longer term. First, with steep initial decline rates in many North American natural gas basins and a substantial reduction in the rig count from the peak, the recent strong natural gas market production growth could slow or even reverse. With respect to international markets, which are typically driven by crude oil prices, the lack of any significant oil production growth over the last five years, despite a more than doubling of international exploration and production capital spending over this period, leads us to believe that production would decline in response to a decrease in exploration and production spending.

Furthermore, the offshore drilling market remains highly competitive and cyclical, and it has historically been difficult to forecast future market conditions. While future commodity price expectations have typically been a key driver for demand for drilling rigs, other factors also affect our customers drilling programs, including the quality of drilling prospects, exploration success, relative production costs, availability of insurance, and political and regulatory environments, including offshore lease access. Additionally, the offshore drilling business has historically been cyclical, marked by periods of low demand, excess rig supply and low dayrates, followed by periods of high demand, short rig supply and increasing dayrates. These cycles have been volatile and are subject to rapid change.

Inland

The activity for inland barge drilling in the U.S. generally follows the same drivers as drilling in the U.S. Gulf of Mexico with activity following operators expectations of prices for natural gas and crude oil. Barge rig drilling activity historically lags activity in the U.S. Gulf of Mexico due to a number of factors such as the lengthy permitting process that operators must go through prior to drilling a well in Louisiana, where the majority of our inland drilling takes place, and the predominance of smaller independent operators active in inland waters.

Inland barge drilling activity has slowed dramatically over the past two years and dayrates have declined as a result of the number of the key operators that have curtailed or ceased their activity in the inland market for various reasons, including lack of funding, lack of drilling success and re-allocation of capital to other onshore basins. Activity has increased recently, with a higher percentage of the drilling focused on crude oil. As of February 24, 2010, all three of our marketed inland barges had contracts for work. While we may have some increased activity for our inland barges based on stronger capital budgets and improved natural gas prices, we expect activity levels to remain very low versus historic norms for 2010.

Liftboats

Demand for liftboats is typically a function of our customers demand for platform inspection and maintenance, well maintenance, offshore construction, well plugging and abandonment, and other related activities. Although activity levels for liftboats are not as closely correlated to movement in commodity prices as for offshore drilling rigs, commodity prices are still a key driver of the demand for liftboats. Despite the production maintenance related nature of the majority of the work, some of the work may be deferred from time to time.

Following the active 2005 hurricane season, which caused tremendous damage to the infrastructure in the U.S. Gulf of Mexico, liftboat utilization and dayrates in the region were stronger than historical levels for approximately two years. As a result of this robust activity, many of our competitors ordered new liftboats and approximately 23 have been delivered for work in the U.S. Gulf of Mexico since January 2007. As of February 24, 2010, we believe that there are another eight liftboats under construction or on order in the U.S. that could potentially be delivered through 2011. Once delivered, these liftboats may further impact the demand and utilization of our domestic liftboat fleet. However, some of these new liftboats in the U.S. Gulf of Mexico could be offset by mobilizations to meet growing demand in other regions.

Our customers growth in international capital spending for the last several years, coupled with an aging infrastructure and significant increases in the cost of alternatives for servicing this infrastructure, has generally resulted in strong demand for our liftboats in West Africa. As international markets mature and the focus shifts from exploration to development in locations such as West Africa, the Middle East and Southeast Asia, we expect to experience strong demand growth for liftboats. We anticipate that there may be contract opportunities in international locations for liftboats currently working in the U.S. Gulf of Mexico and for newly constructed liftboats. In 2008 we mobilized two of our liftboats to the Middle East from the U.S. Gulf of Mexico and we recently mobilized four liftboats to West Africa from the U.S. Gulf of Mexico. While we believe that international demand for liftboats will continue to increase over the longer term, political instability in certain regions may negatively impact our customers capital spending plans.

Table of Contents

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

Sources and uses of cash for 2009 and 2008 are as follows (in millions):

	2009	2008
Net Cash Provided by Operating Activities	$ 138.9	$ 269.9
Net Cash Provided by (Used in) Investing Activities:		
Acquisition of Assets		(320.8)
Additions of Property and Equipment	(76.1)	(264.2)
Deferred Drydocking Expenditures	(15.6)	(17.3)
Sale of Marketable Securities		39.3
Proceeds from Sale of Assets, Net	25.8	17.0
Insurance Proceeds Received	9.1	30.2
Increase in Restricted Cash	(3.7)	
Total	(60.5)	(515.8)
Net Cash Provided by (Used in) Financing Activities:		
Short-term Debt Borrowings (Repayments), Net	(2.5)	2.5
Long-term Debt Borrowings	292.1	350.0
Long-term Debt Repayments	(403.6)	(121.5)
Redemption of 3.375% Convertible Senior Notes	(6.1)	(44.8)
Common Stock Issuance (Repurchase)	89.6	(49.2)
Proceeds from Exercise of Stock Options		5.1
Excess Tax Benefit from Stock-Based Arrangements	4.6	5.9
Payment of Debt Issuance Costs	(18.1)	(8.1)
Total	(44.0)	139.9
Net Increase (Decrease) in Cash and Cash Equivalents	$ 34.4	$ (106.0)

Sources of Liquidity and Financing Arrangements

Our liquidity is comprised of cash on hand, cash from operations and availability under our revolving credit facility. We also maintain a shelf registration statement covering the future issuance from time to time of various types of securities, including debt and equity securities. If we issue any debt securities off the shelf or otherwise incur debt, we would generally be required to allocate the proceeds of such debt to repay or refinance existing debt. We currently believe we will have adequate liquidity to meet the minimum liquidity requirement under our Credit Agreement that governs our $482.9 million term loan and $175.0 million revolving credit facility and to fund our operations. However, to the extent we do not generate sufficient cash from operations we may need to raise additional funds through debt, equity offerings or the sale of assets. Furthermore, we may need to raise additional funds through debt or equity offerings or asset sales to meet certain covenants under the Credit Agreement, to refinance existing debt or for general corporate purposes. In July 2012, our $175.0 million revolving credit facility matures. To the extent we are unsuccessful in extending the maturity or entering into a new revolving credit facility, our liquidity would be negatively impacted. In June 2013, we may be required to settle our 3.375% Convertible Senior Notes. As of December 31, 2009, the notional amount of these notes outstanding was $95.9 million. Additionally, our term loan matures in July 2013 and currently requires a balloon payment of $466.8 million at maturity. We intend to meet these obligations through one or more of the following: cash flow from operations, asset sales, debt refinancing and future debt or equity offerings.

Our Credit Agreement requires that we meet certain financial ratios and tests, which we currently meet. Our failure to comply with such covenants would result in an event of default under the Credit Agreement. An event of default could prevent us from borrowing under the revolving credit facility, which would in turn have a material adverse effect on our available liquidity. Additionally, an event of default could result in us having to immediately repay all amounts outstanding under the term loan facility, the revolving credit facility, our 10.5% Senior Secured Notes and our 3.375% Convertible Senior Notes and in the foreclosure of liens on our assets.

Cash Requirements and Contractual Obligations

Debt

Our current debt structure is used to fund our business operations.

In July 2007, we terminated all prior facilities and entered into a new $1,050.0 million credit facility with a syndicate of financial institutions, consisting of a $900.0 million term loan and a $150.0 million revolving credit facility which is governed by the Credit Agreement. On April 28, 2008, we entered into an agreement to increase the revolving credit facility to $250.0 million.

On July 27, 2009, we amended the Credit Agreement (the Credit Amendment). A fee of 0.50% was paid to lenders consenting to the Credit Amendment, based on their total commitment, which approximated $4.8 million.

The Credit Amendment reduced the revolving credit facility by $75.0 million to $175.0 million. The commitment fee on the revolving credit facility increased from 0.375% to 1.00% and the letter of credit fee with respect to the undrawn amount of each letter of credit issued under the revolving credit facility increased from 1.75% to 4.00% per annum. Additionally, the Credit Amendment establishes a minimum London Interbank Offered Rate (LIBOR) of 2.00% for Eurodollar Loans, a minimum rate of 3.00% with respect to Alternative Base Rate (ABR) Loans, and increases the margin applicable to Eurodollar Loans and ABR Loans, subject to a grid based on the aggregate principal amount of the Term Loans outstanding as follows ($ in millions):

Principal Amount Outstanding		**Margin Applicable to:**	
Less than or equal to:	**Greater than:**	**Eurodollar Loans**	**ABR Loans**
$ 882.00	$ 684.25	6.50%	5.50%
684.25	484.25	5.00%	4.00%
484.25		4.00%	3.00%

The Credit Amendment also modifies certain provisions of the Credit Agreement to, among other things:

- Eliminate the requirement that we comply with the total leverage ratio financial covenant for the nine month period commencing October 1, 2009 and ending on June 30, 2010.

- Amend the maximum total leverage ratio that we must comply with to the following schedule. The total leverage ratio for any test period is calculated as the ratio of consolidated indebtedness on the test date to consolidated EBITDA for the trailing twelve months, all as defined in the Credit Agreement.

Test Date	**Maximum Total Leverage Ratio**
September 30, 2010	8.00 to 1.00
December 31, 2010	7.50 to 1.00

March 31, 2011	7.00 to 1.00
June 30, 2011	6.75 to 1.00
September 30, 2011	6.00 to 1.00
December 31, 2011	5.50 to 1.00
March 31, 2012	5.25 to 1.00
June 30, 2012	5.00 to 1.00
September 30, 2012	4.75 to 1.00
December 31, 2012	4.50 to 1.00
March 31, 2013	4.25 to 1.00
June 30, 2013	4.00 to 1.00

- At December 31, 2009, our total leverage ratio was 5.32.

Require us to maintain a minimum level of liquidity, measured as the amount of unrestricted cash and cash equivalents we have on hand and availability under the revolving credit facility, of (i) $100.0 million for the period between October 1, 2009 through December 31, 2010, (ii) $75.0 million during calendar year 2011 and (iii) $50.0 million thereafter. As of December 31, 2009, as calculated pursuant to our Credit Agreement, our total liquidity was $305.8 million.

Revise the consolidated fixed charge coverage ratio definition and reduce the minimum fixed charge coverage ratio that we must maintain to the following schedule:

Period		Fixed Charge Coverage Ratio
July 1, 2009	December 31, 2011	1.00 to 1.00
January 1, 2012	March 31, 2012	1.05 to 1.00
April 1, 2012	June 30, 2012	1.10 to 1.00
July 1, 2012 and thereafter		1.15 to 1.00

The consolidated fixed charge coverage ratio for any test period is defined as the sum of consolidated EBITDA for the test period plus an amount that may be added for the purpose of calculating the ratio for such test period, not to exceed $130.0 million in total during the term of the credit facility, to consolidated fixed charges for the test period, all as defined in the Credit Agreement. As of December 31, 2009, our fixed charge coverage ratio was 1.0.

Require mandatory prepayments of debt outstanding under the Credit Agreement with 100% of excess cash flow as defined in the Credit Agreement for the fiscal year ending December 31, 2009 and 50% of excess cash flow thereafter and with proceeds from:

unsecured debt issuances, with the exception of refinancing, through June 30, 2010;

secured debt issuances;

sales of assets in excess of $25 million annually; and

unless we have achieved a specified leverage ratio, 50% of proceeds from equity issuances, excluding those for permitted acquisitions or to meet the minimum liquidity requirements.

The credit facility consists of a $482.9 million term loan which matures on July 11, 2013 and a $175.0 million revolving credit facility which matures on July 11, 2012. The availability under the $175.0 million revolving credit facility must be used for working capital, capital expenditures and other general corporate purposes and cannot be used to prepay our term loan. As of December 31, 2009, no amounts were outstanding and $10.0 million in stand-by letters of credit had been issued under the revolving credit facility, therefore the remaining availability under this revolving credit facility was $165.0 million. Other than the required prepayments as outlined previously, the principal amount of the term loan amortizes in equal quarterly installments of approximately $1.2 million, with the balance due on July 11, 2013. Interest payments on both the revolving and term loan facility are due at least on a quarterly basis and in certain instances, more frequently. In addition to our scheduled payments, during the fourth quarter of 2009, we used the net proceeds from the partial exercise of the underwriters over-allotment option and the 10.5% Senior Secured Notes due 2017, which approximated $287.5 million, as well as cash on hand to retire $379.6 million of the outstanding balance on our term loan facility. In connection with the early retirement, we recorded a pretax charge of $1.6 million, $1.0 million, net of tax, related to the write off of unamortized issuance costs. As of December 31, 2009, $482.9 million was outstanding on the term loan facility and the interest rate was 6.00%. The annualized effective interest rate was 7.18% for the year ended December 31, 2009 after giving consideration to revolver fees and derivative activity.

Other covenants contained in the Credit Agreement restrict, among other things, asset dispositions, mergers and acquisitions, dividends, stock repurchases and redemptions, other restricted payments, debt issuances, liens, investments, convertible notes repurchases and affiliate transactions. The Credit Agreement also contains a provision under which an event of default on any other indebtedness exceeding $25.0 million would be considered an event of default under our Credit Agreement.

In May 2008 and July 2007, we entered into derivative instruments with the purpose of hedging future interest payments on our term loan facility. We entered into a floating-to-fixed interest rate swap with varying notional amounts beginning with $100.0 million with a settlement date of October 1, 2008 and ending with $75.0 million which was settled on December 31, 2009. We received an interest rate of three-month LIBOR and paid a fixed coupon of 2.980% over six quarters. The terms and settlement dates of the swap matched those of the term loan through July 27, 2009, the date of the Credit Amendment. We also entered into a zero cost LIBOR collar on $300.0 million of term loan principal with a final settlement date of October 1, 2010 with a ceiling of 5.75% and a floor of 4.99%. The counterparty is obligated to pay us in any quarter that actual LIBOR resets above 5.75% and we pay the counterparty in any quarter that actual LIBOR resets below 4.99%. The terms and settlement dates of the collar matched those of the term loan through July 27, 2009, the date of the Credit Amendment. As a result of the inclusion of a LIBOR floor in the Credit Agreement, we do not believe, as of July 27, 2009 and on an ongoing basis, that the interest rate swap and collar will be highly effective in achieving offsetting changes in cash flows attributable to the hedged interest rate risk during the period that the hedge was designated. As such, we have prospectively discontinued cash flow hedge accounting for the interest rate swap and collar as of July 27, 2009 and no longer apply cash flow hedge accounting to these instruments. Because cash flow hedge accounting will not be applied to these instruments, changes in fair value related to the interest rate swap and collar subsequent to July 27, 2009 have been recorded in earnings and will be on a go-forward basis. As a result of discontinuing the cash flow hedging relationship, we recognized a decrease in fair value of $1.7 million related to the hedge ineffectiveness of our interest rate swap and collar as Interest Expense in our Consolidated Statements of Operations for the year ended December 31, 2009. We did not recognize a gain or loss due to hedge ineffectiveness in the Consolidated Statements of Operations for the years ended December 31, 2008 or 2007 related to interest rate derivative instruments. The change in the fair value of our hedging instruments resulted in a decrease in derivative liabilities of $12.7 million during the year ended December 31, 2009. We had net unrealized gains on hedge transactions of $9.2 million, net of tax of $4.9 million for the year ended December 31, 2009, and net unrealized losses on hedge transactions of $6.8 million, net of tax of $3.7 million and $8.9 million, net of tax of $4.8 million for the years ended December 31, 2008 and 2007, respectively. Overall, our interest expense was increased by $18.3 million and $7.7 million during the years ended December 31, 2009 and 2008, respectively and was decreased by $0.2 million during the year ended December 31, 2007, as a result of our interest rate derivative instruments.

On October 20, 2009, we completed an offering of $300.0 million of senior secured notes at a coupon rate of 10.5% (10.5% Senior Secured Notes) with a maturity in October 2017. The interest on the notes will be payable in cash semi-annually in arrears on April 15 and October 15 of each year, commencing on April 15, 2010, to holders of record at the close of business on April 1 or October 1. Interest on the notes will be computed on the basis of a 360-day year of twelve 30-day months. The notes were sold at 97.383% of their face amount to yield 11.0% and were recorded at their discounted amount, with the discount to be amortized over the life of the notes. We used the net proceeds of approximately $284.4 million from the offering to repay a portion of the indebtedness outstanding under our term loan facility. As of December 31, 2009, $300.0 million notional amount of the 10.5% Senior Secured Notes was outstanding. The carrying amount of the 10.5% Senior Secured Notes was $292.3 million at December 31, 2009.

The notes are guaranteed by all of our existing and future restricted subsidiaries that incur or guarantee indebtedness under a credit facility, including our existing credit facility. The notes are secured by liens on all collateral that secures our obligations under our secured credit facility, subject to limited exceptions. The liens securing the notes share on an equal and ratable first priority basis with liens securing our credit facility. Under the intercreditor agreement, the collateral agent for the lenders under our secured credit facility are generally entitled to sole control of all decisions and actions.

All the liens securing the notes may be released if our secured indebtedness, other than these notes, does not exceed the lesser of $375.0 million and 15.0% of our consolidated tangible assets. We refer to such a release as a collateral suspension. If a collateral suspension is in effect, the notes and the guarantees will be unsecured, and will effectively rank junior to our secured indebtedness. If, after any such release of liens on collateral, the aggregate principal amount of our secured indebtedness, other than these notes, exceeds the greater of $375.0 million and 15.0% of our consolidated tangible assets, as defined in the indenture, then the collateral obligations of the company and guarantors will be reinstated and must be complied with within 30 days of such event.

The indenture governing the notes contains covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to:

- incur additional indebtedness or issue certain preferred stock;
- pay dividends or make other distributions;
- make other restricted payments or investments;
- sell assets;
- create liens;
- enter into agreements that restrict dividends and other payments by restricted subsidiaries;
- engage in transactions with our affiliates; and
- consolidate, merge or transfer all or substantially all of our assets.

The indenture governing the notes also contains a provision under which an event of default by us or by any restricted subsidiary on any other indebtedness exceeding $25.0 million would be considered an event of default under the indenture if such default is: a) caused by failure to pay the principal at final maturity, or b) results in the acceleration of such indebtedness prior to maturity.

Prior to October 15, 2012, we may redeem the notes with the net cash proceeds of certain equity offerings, at a redemption price equal to 110.50% of the aggregate principal amount plus accrued and unpaid interest; provided, that (i) after giving effect to any such redemption, at least 65% of the notes originally issued would remain outstanding immediately after such redemption and (ii) we make such redemption not more than 90 days after the consummation of such equity offering. In addition, prior to October 15, 2013, we may redeem all or part of the notes at a price equal to 100% of the aggregate principal amount of notes to be redeemed, plus the applicable premium, as defined in the indenture, and accrued and unpaid interest.

On or after October 15, 2013, we may redeem the notes, in whole or part, at the redemption prices set forth below, together with accrued and unpaid interest to the redemption date.

Year	Optional Redemption Price
2013	105.2500%
2014	102.6250%
2015	101.3125%
2016 and thereafter	100.0000%

If we experience certain kinds of changes of control, we must offer to repurchase the notes at an offer price in cash equal to 101% of their principal amount, plus accrued and unpaid interest. Furthermore, following certain asset sales, we may be required to use the proceeds to offer to repurchase the notes at an offer price in cash equal to 100% of their principal amount, plus accrued and unpaid interest.

On June 3, 2008, we completed an offering of $250.0 million convertible senior notes at a coupon rate of 3.375% (3.375% Convertible Senior Notes) with a maturity in June 2038. As of December 31, 2009, $95.9 million notional amount of the $250.0 million 3.375% Convertible Senior Notes was outstanding. The carrying amount of the 3.375% Convertible Senior Notes was $83.1 million at December 31, 2009.

The interest on the 3.375% Convertible Senior Notes is payable in cash semi-annually in arrears, on June 1 and December 1 of each year until June 1, 2013, after which the principal will accrete at an annual yield to maturity of 3.375% per year. We will also pay contingent interest during any six-month interest period commencing June 1, 2013, for which the trading price of these notes for a specified period of time equals or exceeds 120% of their accreted principal amount. The notes will be convertible under certain circumstances into shares of our common stock (Common Stock) at an initial conversion rate of 19.9695 shares of Common Stock per $1,000 principal amount of notes, which is equal to an initial conversion price of

Table of Contents

approximately $50.08 per share. Upon conversion of a note, a holder will receive, at our election, shares of Common Stock, cash or a combination of cash and shares of Common Stock. At December 31, 2009, the number of conversion shares potentially issuable in relation to our 3.375% Convertible Senior Notes was 1.9 million. We may redeem the notes at our option beginning June 6, 2013, and holders of the notes will have the right to require us to repurchase the notes on June 1, 2013 and certain dates thereafter or on the occurrence of a fundamental change.

The indenture governing the 3.375% Convertible Senior Notes contains a provision under which an event of default by us or by any subsidiary on any other indebtedness exceeding $25.0 million would be considered an event of default under the indenture if such default: a) is caused by failure to pay the principal at final maturity, or b) results in the acceleration of such indebtedness prior to maturity.

During December 2008 and April 2009, we repurchased $88.2 million and $20.0 million aggregate principal amount of the 3.375% Convertible Senior Notes, respectively, for a cost of $44.8 million and $6.1 million, respectively. In addition, during December 2008 and April 2009 we recognized a gain of $28.4 million and $10.7 million, respectively and expensed $2.1 million and $0.4 million of unamortized issuance costs, respectively, in connection with the retirement. In June 2009, we retired $45.8 million aggregate principal amount of its 3.375% Convertible Senior Notes in exchange for the issuance of 7,755,440 shares of Common Stock valued at $4.38 per share and payment of accrued interest, resulting in a gain of $4.4 million. In addition, we expensed $1.0 million of unamortized issuance costs in connection with the retirement. The settlement consideration was allocated to the extinguishment of the liability component in an amount equal to the fair value of that component immediately prior to extinguishment, with the difference between this allocation and the net carrying amount of the liability component and unamortized debt issuance costs recognized as a gain or loss on debt extinguishment. If there would have been any remaining settlement consideration, it would have been allocated to the reacquisition of the equity component and recognized as a reduction of Stockholders Equity.

The Company also had a foreign overdraft facility, which was designed to manage local currency liquidity in Venezuela. This facility was terminated in March 2009 and all outstanding amounts were repaid.

The fair value of our 3.375% Convertible Senior Notes, 10.5% Senior Secured Notes and term loan facility is estimated based on quoted prices in active markets. The fair value of our 7.375% Senior Notes is estimated based on discounted cash flows using inputs from quoted prices in active markets for similar debt instruments. We believe the carrying value of our short-term debt instruments outstanding at December 31, 2008 approximate fair value. The following table provides the carrying value and fair value of our long-term debt instruments:

	December 31, 2009		December 31, 2008	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Term Loan Facility, due July 2013	$ 482.9	$ 468.4	$ 886.5	$ 571.8
10.5% Senior Secured Notes, due October 2017	292.3	315.8	n/a	n/a
3.375% Convertible Senior Notes due June 2038	83.1	76.8	134.8	77.2
7.375% Senior Notes, due April 2018	3.5	3.0	3.5	2.5

In May 2009, we completed the annual renewal of all of our key insurance policies. Our primary marine package provides for hull and machinery coverage for our rigs and liftboats up to a scheduled value for each asset. The maximum coverage for these assets is $2.2 billion; however, coverage for U.S. Gulf of Mexico named windstorm damage is subject to an annual aggregate limit on liability of $100.0 million. The policies are subject to exclusions, limitations, deductibles, self-insured retention and other conditions. Deductibles for events that are not U.S. Gulf of Mexico named windstorm events are 12.5% of insured values per occurrence for drilling rigs, and $1.0 million per occurrence for liftboats, regardless of the insured value of the particular vessel. The deductibles for drilling rigs and liftboats in a U.S. Gulf of Mexico named windstorm event are the greater of $25.0 million or the operational deductible for each U.S. Gulf of Mexico named windstorm. We are self-insured for 15% above the deductibles for removal of wreck, sue and labor, collision, protection and indemnity general liability and hull and physical damage policies. The protection and indemnity coverage under the primary marine package has a $5.0 million limit per occurrence with excess liability coverage up to $200.0 million. The primary marine package also provides coverage for cargo and charterer s legal liability. Vessel pollution is covered under a Water Quality Insurance Syndicate policy with a $3 million deductible proving limits as required. In addition to the marine package, we have separate policies providing coverage for onshore general liability, employer s liability, auto liability and non-owned aircraft liability, with customary deductibles and coverage as well as a separate primary marine package for our Delta Towing business.

In 2009, in connection with the renewal of certain of our insurance policies, we entered into agreements to finance a portion of our annual insurance premiums. Approximately $23.3 million was financed through these arrangements, and $5.5 million was outstanding at December 31, 2009. The interest rate on the $21.4 million note is 4.15% and it is scheduled to mature in March 2010. The interest rate on the $1.9 million note is 3.75% and it is scheduled to mature in July 2010. The amounts financed in connection with the prior year renewal were fully paid as of March 31, 2009.

Common Stock Offering

In September 2009, we raised approximately $82.3 million in net proceeds from an underwritten public offering of 17,500,000 shares of our common stock. In addition, on October 9, 2009, we sold an additional 1,313,590 shares of our common stock pursuant to the partial exercise of the underwriters over-allotment option and raised an additional $6.3 million in net proceeds. We used a portion of the net proceeds from these sales of common stock to repay a portion of our outstanding indebtedness under our term loan facility, and may use some or all of the remaining proceeds to repay additional indebtedness.

Capital Expenditures

We expect to spend approximately $60 million on capital expenditures and drydocking during 2010. Planned capital expenditures include refurbishment or upgrades to certain of our rigs, liftboats, and other marine vessels. The timing and amounts we actually spend in connection with our plans to upgrade and refurbish other selected rigs and liftboats are subject to our discretion and will depend on our view of market conditions and our cash flows. Furthermore, should we elect to reactivate cold stacked rigs, our capital expenditures may increase.

Costs associated with refurbishment or upgrade activities which substantially extend the useful life or operating capabilities of the asset are capitalized. Refurbishment entails replacing or rebuilding the operating equipment. An upgrade entails increasing the operating capabilities of a rig or liftboat. This can be accomplished by a number of means, including adding new or higher specification equipment to the unit, increasing the water depth capabilities or increasing the capacity of the living quarters, or a combination of each.

We are required to inspect and drydock our liftboats on a periodic basis to meet U.S. Coast Guard requirements. The amount of expenditures is impacted by a number of factors, including, among others, our ongoing maintenance expenditures, adverse weather, changes in regulatory requirements and operating conditions. In addition, from time to time we agree to perform modifications to our rigs and liftboats as part of a contract with a customer. When market conditions allow, we attempt to recover these costs as part of the contract cash flow.

From time to time, we may review possible acquisitions of rigs, liftboats or businesses, joint ventures, mergers or other business combinations, and we may have outstanding from time to time bids to acquire certain assets from other companies. We may not, however, be successful in our acquisition efforts. We are generally restricted by our Credit Agreement from making acquisitions for cash consideration, except to the extent the acquisition is funded by an issuance of our stock or cash proceeds from the issuance of stock, or unless we are in compliance with our financial covenants as they existed prior to the Credit Amendment. If we acquire additional assets, we would expect that the ongoing capital expenditures for our company as a whole would increase in order to maintain our equipment in a competitive condition.

Table of Contents

Our ability to fund capital expenditures would be adversely affected if conditions deteriorate in our business.

Contractual Obligations

Our contractual obligations and commitments principally include obligations associated with our outstanding indebtedness, certain income tax liabilities, surety bonds, letters of credit, future minimum operating lease obligations, purchase commitments and management compensation obligations.

The following table summarizes our contractual obligations and contingent commitments by period as of December 31, 2009:

	Payments due by Period				
Contractual Obligations and Contingent Commitments	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**After 5 Years**	**Total**
			(In thousands)		
Recorded Obligations:					
Long-term debt obligations	$ 4,952	$ 9,904	$ 563,919	$ 303,508	$ 882,283
Insurance notes payable	5,484				5,484
Interest on debt and notes payable(c)	16,936				16,936
Tax liabilities(b)	18,554				18,554
Purchase obligations(a)	3,574				3,574
Other	2,756				2,756
Unrecorded Obligations:					
Interest on debt and notes payable(c)	59,739	138,160	83,918	95,406	377,223
Letters of credit	1,099	9,961			11,060
Surety bonds	37,469				37,469
Management compensation obligations	3,293	6,318			9,611
Purchase obligations(a)	4,546				4,546
Operating lease obligations	5,578	5,526	4,235	6,490	21,829
Total contractual obligations	$ 163,980	$ 169,869	$ 652,072	$ 405,404	$ 1,391,325

(a) A purchase obligation is defined as an agreement to purchase goods or services that is enforceable and legally binding on the company and that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transaction. These amounts are primarily comprised of open purchase order commitments to vendors and subcontractors.

(b) Tax liabilities of $9.3 million have been excluded from the table above as a reasonably reliable estimate of the period of cash settlement cannot be made.

(c) Estimated Interest on our Term Loan Facility and Interest Rate Collar is based on 3 month LIBOR reset quarterly and extrapolated from the forward curve dated as of the balance sheet date. There was $482.9 million outstanding under our Term Loan Facility as of December 31, 2009 and the interest estimates above assume the reduction in principal related to scheduled principal payments. The remaining interest estimates are based on the rates associated with the respective fixed rate instrument.

Off-Balance Sheet Arrangements

Guarantees

Our obligations under the credit facility and 10.5% Senior Secured Notes are secured by liens on a majority of our vessels and substantially all of our other personal property. Substantially all of our domestic subsidiaries, and several of our international subsidiaries, guarantee the obligations under the credit facility and 10.5% Senior Secured Notes and have granted similar liens on several of their vessels and substantially all of their other personal property.

Letters of Credit and Surety Bonds

We execute letters of credit and surety bonds in the normal course of business. While these obligations are not normally called, these obligations could be called by the beneficiaries at any time before the expiration date should we breach certain contractual or payment obligations. As of December 31, 2009, we had $48.5 million of letters of credit and surety bonds outstanding, consisting of $1.0 million in unsecured outstanding letters of credit, $10.0 million letters of credit outstanding under our revolver and $37.5 million outstanding in surety bonds that guarantee our performance as it relates to our drilling contracts, insurance, tax and other obligations primarily in Mexico. If the beneficiaries called these letters of credit and surety bonds, the called amount would become an on-balance sheet liability, and we would be required to settle the liability with cash on hand or through borrowings under our available line of credit. We have restricted cash of $3.7 million to support surety bonds primarily related to the Company s Mexico operations.

Accounting Pronouncements

In June 2009, the FASB issued SFAS No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles, a replacement of FASB Statement No. 162* (SFAS No. 168). SFAS No. 168 modifies the Generally Accepted Accounting Principles (GAAP) hierarchy by establishing only two levels of GAAP, authoritative and nonauthoritative accounting literature. Effective July 2009, the FASB Accounting Standards Codification (ASC), also known collectively as the Codification is considered the single source of authoritative U.S. accounting and reporting standards, except for additional authoritative rules and interpretive releases issued by the SEC. Nonauthoritative guidance and literature would include, among other things, FASB Concepts Statements, American Institute of Certified Public Accountants Issue Papers and Technical Practice Aids and accounting textbooks. The Codification was developed to organize GAAP pronouncements by topic so that users can more easily access authoritative accounting guidance. It is organized by topic, subtopic, section, and paragraph, each of which is identified by a numerical designation. This statement is effective for financial statements issued for interim and annual periods ending after September 15, 2009. Accordingly, accounting references have been updated.

In August 2009, the FASB issued *Accounting Standards Update (ASU) No. 2009-05, Fair Value Measurements and Disclosures (Topic 820) Measuring Liabilities at Fair Value* (ASU No. 2009-5), which amends Subtopic 820-10, *Fair Value Measurements and Disclosures-Overall* for the fair value measurement of liabilities. ASU No. 2009-5 provides clarification that in circumstances in which a quoted price in an active market for the identical liability is not available, a reporting entity is required to measure fair value using one or more of the following techniques: (1) a valuation technique that uses the quoted price of the identical liability or similar liabilities when traded as assets; or (2) another valuation technique that is consistent with the principles of Topic 820, such as a present value technique or market approach. ASU No. 2009-5 is effective for the first reporting period after issuance. Accordingly, we adopted ASU No. 2009-5 in the third quarter 2009 with no impact to our financial statements.

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events* (SFAS No. 165), which was primarily codified into Topic 855, *Subsequent Events* in the ASC. SFAS No. 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date, but before financial statements are issued or are available to be issued. SFAS No. 165 requires disclosure of the date through which an entity has evaluated subsequent events and the basis for that date. This statement is effective for interim or annual financial periods ending after June 15, 2009. Accordingly, we adopted SFAS No. 165 in June 2009 with no impact to our financial statements.

In April 2009, the FASB issued FSP No. FAS 107-1 and APB 28-1 *Interim Disclosures about Fair Value of Financial Instruments* (FSP 107-1), which was primarily codified into Topic 825, *Financial Instruments* in the ASC. This FSP extends the disclosure requirements of SFAS No. 107, *Disclosures about Fair Value of Financial Instruments*, to interim financial statements of publicly traded companies as defined in APB Opinion No. 28, *Interim Financial reporting*. This statement is effective for interim periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. Accordingly, we adopted FSP 107-1 in June 2009 with no impact to our financial statements.

In April 2009, the FASB issued FSP No. FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset and Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly* (FSP 157-4) which was primarily codified into Topic 820, *Fair Value Measurements and Disclosures* in the ASC. This FSP provides additional guidance on estimating fair value when the volume and level of transaction activity for an asset or liability have significantly decreased in relation to normal market activity for the asset or liability. The FSP also provides additional guidance on circumstances that may indicate that a transaction is not orderly. This statement is effective for interim or annual financial periods ending after June 15, 2009. Accordingly, we adopted FSP 157-4 in June 2009 with no impact to our financial statements.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities* (SFAS No. 161), which was primarily codified into Topic 815, *Derivatives and Hedging* in the ASC. SFAS No. 161 amends SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* requiring enhanced disclosures about an entity s derivative and hedging activities, thereby improving the transparency of financial reporting. SFAS No. 161 s disclosures provide additional information on how and why derivative instruments are being used. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. Accordingly, we adopted SFAS No. 161 as of January 1, 2009 with no impact to our financial statements.

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K includes 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. All statements, other than statements of historical fact, included in this annual report that address outlook, activities, events or developments that we expect, project, believe or anticipate will or may occur in the future are forward-looking statements. These include such matters as:

- our levels of indebtedness, covenant compliance and access to capital under current market conditions;
- our ability to enter into new contracts for our rigs and liftboats and future utilization rates and dayrates for the units;
- our ability to renew or extend our long-term international contracts, or enter into new contracts, when such contracts expire;
- demand for our rigs and our liftboats and our earnings;
- activity levels of our customers and their expectations of future energy prices;

sufficiency and availability of funds for required capital expenditures, working capital and debt service;

levels of reserves for accounts receivable;

success of our cost cutting measures and plans to dispose of certain assets;

expected completion times for our refurbishment and upgrade projects;

our plans to increase international operations;

expected useful lives of our rigs and liftboats;

Table of Contents

future capital expenditures and refurbishment, reactivation, transportation, repair and upgrade costs;

our ability to effectively reactivate rigs that we have recently stacked;

liabilities and restrictions under coastwise laws of the United States and regulations protecting the environment;

expected outcomes of litigation, claims and disputes and their expected effects on our financial condition and results of operations; and

expectations regarding offshore drilling activity and dayrates, market conditions, demand for our rigs and liftboats, operating revenues, operating and maintenance expense, insurance coverage, insurance expense and deductibles, interest expense, debt levels and other matters with regard to outlook.

We have based these statements on our assumptions and analyses in light of our experience and perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate in the circumstances. Forward-looking statements by their nature involve substantial risks and uncertainties that could significantly affect expected results, and actual future results could differ materially from those described in such statements. Although it is not possible to identify all factors, we continue to face many risks and uncertainties. Among the factors that could cause actual future results to differ materially are the risks and uncertainties described under Risk Factors in Item 1A of this annual report and the following:

oil and natural gas prices and industry expectations about future prices;

levels of oil and gas exploration and production spending;

demand and supply for offshore drilling rigs and liftboats;

our ability to enter into and the terms of future contracts;

the worldwide military and political environment, uncertainty or instability resulting from an escalation or additional outbreak of armed hostilities or other crises in the Middle East, West Africa and other oil and natural gas producing regions or acts of terrorism or piracy;

the impact of governmental laws and regulations;

the adequacy and costs of sources of credit and liquidity;

uncertainties relating to the level of activity in offshore oil and natural gas exploration, development and production;

competition and market conditions in the contract drilling and liftboat industries;

the availability of skilled personnel in view of recent reductions in our personnel;

labor relations and work stoppages, particularly in the West African and Mexican labor environments;

operating hazards such as hurricanes, severe weather and seas, fires, cratering, blowouts, war, terrorism and cancellation or unavailability of insurance coverage or insufficient coverage;

the effect of litigation and contingencies; and

our inability to achieve our plans or carry out our strategy.

Many of these factors are beyond our ability to control or predict. Any of these factors, or a combination of these factors, could materially affect our future financial condition or results of operations and the ultimate accuracy of the forward-looking statements. These forward-looking statements are not guarantees of our future performance, and our actual results and future developments may differ materially from those projected in the forward-looking statements. Management cautions against putting undue reliance on forward-looking statements or projecting any future results based on such statements or present or prior earnings levels. In addition, each forward-looking statement speaks only as of the date of the particular statement, and we undertake no obligation to publicly update or revise any forward-looking statements except as required by applicable law.

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

We are currently exposed to market risk from changes in interest rates. From time to time, we may enter into derivative financial instrument transactions to manage or reduce our market risk, but we do not enter into derivative transactions for speculative purposes. A discussion of our market risk exposure in financial instruments follows.

Interest Rate Exposure

We are subject to interest rate risk on our fixed-interest and variable-interest rate borrowings. Variable rate debt, where the interest rate fluctuates periodically, exposes us to short-term changes in market interest rates. Fixed rate debt, where the interest rate is fixed over the life of the instrument, exposes us to changes in market interest rates reflected in the fair value of the debt and to the risk that we may need to refinance maturing debt with new debt at a higher rate.

As of December 31, 2009, the long-term borrowings that were outstanding subject to fixed interest rate risk consisted of the 7.375% Senior Notes due April 2018, the 3.375% Convertible Senior Notes due June 2038 and the 10.5% Senior Secured Notes due October 2017 with a carrying amount of $3.5 million, $83.1 million, and $292.3 million, respectively.

As of December 31, 2009 the interest rate for the $482.9 million outstanding under the term loan was 6.00%. If the interest rate averages 1% more for 2010 than the rates as of December 31, 2009, annual interest expense would increase by approximately $4.8 million. This sensitivity analysis assumes there are no changes in our financial structure and excludes the impact of our derivatives.

The fair value of our 3.375% Convertible Senior Notes, 10.5% Senior Secured Notes and term loan facility is estimated based on quoted prices in active markets. The fair value of our 7.375% Senior Notes is estimated based on discounted cash flows using inputs from quoted prices in active markets for similar debt instruments. We believe the carrying value of our short-term debt instruments outstanding at December 31, 2008 approximate fair value. The following table provides the carrying value and fair value of our long-term debt instruments:

	December 31, 2009		December 31, 2008	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Term Loan Facility, due July 2013	$ 482.9	$ 468.4	$ 886.5	$ 571.8
10.5% Senior Secured Notes due October 2017	292.3	315.8	n/a	n/a
3.375% Convertible Senior Notes due June 2038	83.1	76.8	134.8	77.2
7.375% Senior Notes, due April 2018	3.5	3.0	3.5	2.5

Interest Rate Swaps and Derivatives

We manage our debt portfolio to achieve an overall desired position of fixed and floating rates and may employ hedge transactions such as interest rate swaps and zero cost LIBOR collars as tools to achieve that goal. The major risks from interest rate derivatives include changes in the interest rates affecting the fair value of such instruments, potential increases in interest expense due to market decreases in floating interest rates and the creditworthiness of the counterparties in such transactions. The counterparty to our zero cost LIBOR collar is a creditworthy multinational commercial bank. We believe that the risk of counterparty nonperformance is not currently material, but counterparty risk has recently increased throughout the financial system. Our interest expense was increased by $18.3 million in 2009 as a result of our interest rate derivative transactions. (See the information set forth under the caption Debt in Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations -*Liquidity and Capital Resources*.)

In connection with the credit facility, in July 2007 we entered into a floating to fixed interest rate swap with the purpose of fixing the interest rate on decreasing notional amounts beginning with $400.0 million with a settlement date of December 31, 2007 and ending with $50.0 million which was settled on April 1, 2009.

We also entered into a zero cost LIBOR collar on $300.0 million of term loan principal with a final settlement date of October 1, 2010, with a ceiling of 5.75% and a floor of 4.99%.

In addition, as it relates to our term loan, in May 2008 we entered into a floating to fixed interest rate swap with the purpose of fixing the interest rate on varying notional amounts beginning with $100.0 million with a settlement date of October 1, 2008 and ending with $75.0 million which was settled as of December 31, 2009, per the agreement.

As a result of the inclusion of a LIBOR floor in the Credit Agreement, we do not believe, as of July 27, 2009 and on an ongoing basis, that the interest rate swap and collar will be highly effective in achieving offsetting changes in cash flows attributable to the hedged interest rate risk during the period that the hedge was designated. As such, we prospectively discontinued cash flow hedge accounting for the interest rate swap and collar as of July 27, 2009. Because cash flow hedge accounting is not applied to these instruments for periods after July 27, 2009, changes in fair value related to the interest rate swap and collar subsequent to July 27, 2009 are recorded in earnings. We recognized a decrease in fair value of $1.7 million related to the hedge ineffectiveness of our interest rate swap and collar as Interest Expense in our Consolidated Statements of Operations for the year ended December 31, 2009.

Item 8. ***Financial Statements and Supplementary Data***

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and
Stockholders of Hercules Offshore, Inc.:

We have audited the accompanying consolidated balance sheets of Hercules Offshore, Inc. and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders equity, comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Hercules Offshore, Inc. and subsidiaries at December 31, 2009 and 2008, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, on January 1, 2009, the Company adopted Financial Accounting Standards Board (FASB) Staff Position No. APB 14-1, Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement) (codified in FASB ASC Topic 470, Debt) and, as required, the consolidated financial statements have been adjusted for retrospective application. As discussed in Note 16 to the consolidated financial statements, in 2007, the Company adopted the provisions of FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes (codified in FASB ASC Topic 740, Income Taxes).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Hercules Offshore, Inc. s internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2010, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 1, 2010

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and
Stockholders of Hercules Offshore, Inc.:

We have audited Hercules Offshore, Inc. and subsidiaries internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Hercules Offshore, Inc. and subsidiaries management is responsible 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 an opinion on the company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

In our opinion, Hercules Offshore, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Hercules Offshore, Inc. and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders equity, comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2009 of Hercules Offshore, Inc. and subsidiaries, and our report dated March 1, 2010, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas

March 1, 2010

Table of Contents

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(In thousands, except par value)	
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$ 140,828	$ 106,455
Restricted Cash	3,658	
Accounts Receivable, Net of Allowance for Doubtful Accounts of $38,522 and $7,756 as of December 31, 2009 and 2008, respectively	133,662	293,089
Prepaids	13,706	23,033
Current Deferred Tax Asset	22,885	17,379
Assets Held for Sale		39,623
Other	6,675	19,946
	321,414	499,525
Property and Equipment, Net	1,923,603	2,049,030
Other Assets, Net	32,459	42,340
	$ 2,277,476	$ 2,590,895
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Short-term Debt and Current Portion of Long-term Debt	$ 4,952	$ 11,455
Insurance Notes Payable	5,484	11,126
Accounts Payable	51,868	99,823
Accrued Liabilities	67,773	83,424
Interest Payable	6,624	506
Taxes Payable	5,671	32,440
Other Current Liabilities	34,229	35,966
	176,601	274,740
Long-term Debt, Net of Current Portion	856,755	1,015,764
Other Liabilities	19,809	35,529
Deferred Income Taxes	245,799	339,547
Commitments and Contingencies		
Stockholders Equity:		
Common Stock, $0.01 Par Value; 200,000 Shares Authorized; 116,154 and 89,459 Shares Issued, Respectively; 114,650 and 87,976 Shares Outstanding, Respectively	1,162	895
Capital in Excess of Par Value	1,921,037	1,785,462
Treasury Stock, at Cost, 1,504 Shares and 1,483 Shares, Respectively	(50,151)	(50,081)

Accumulated Other Comprehensive Loss	(5,773)	(14,932)
Retained Deficit	(887,763)	(796,029)
	978,512	925,315
	$ 2,277,476	$ 2,590,895

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

Table of Contents

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2009	2008	2007
	(In thousands, except per share data)		
Revenues	$ 742,851	$ 1,111,807	$ 726,278
Costs and Expenses:			
Operating Expenses	514,136	631,711	346,191
Impairment of Goodwill		950,287	
Impairment of Property and Equipment	26,882	376,668	
Depreciation and Amortization	201,421	192,894	104,634
General and Administrative	92,558	81,160	49,811
	834,997	2,232,720	500,636
Operating Income (Loss)	(92,146)	(1,120,913)	225,642
Other Income (Expense):			
Interest Expense	(77,986)	(63,778)	(34,859)
Expense of Credit Agreement Fees	(15,073)		
Gain (Loss) on Early Retirement of Debt, Net	12,157	26,345	(2,182)
Other, Net	3,967	3,315	6,483
Income (Loss) Before Income Taxes	(169,081)	(1,155,031)	195,084
Income Tax Benefit (Provision)	78,932	73,161	(59,072)
Income (Loss) from Continuing Operations	(90,149)	(1,081,870)	136,012
Income (Loss) from Discontinued Operation, Net of Taxes	(1,585)	(1,520)	510
Net Income (Loss)	$ (91,734)	$ (1,083,390)	$ 136,522
Basic Earnings (Loss) Per Share:			
Income (Loss) from Continuing Operations	$ (0.93)	$ (12.25)	$ 2.31
Income (Loss) from Discontinued Operation	(0.01)	(0.01)	0.01
Net Income (Loss)	$ (0.94)	$ (12.26)	$ 2.32
Diluted Earnings (Loss) Per Share:			
Income (Loss) from Continuing Operations	$ (0.93)	$ (12.25)	$ 2.28
Income (Loss) from Discontinued Operation	(0.01)	(0.01)	0.01
Net Income (Loss)	$ (0.94)	$ (12.26)	$ 2.29
Weighted Average Shares Outstanding:			
Basic	97,114	88,351	58,897

Diluted	97,114	88,351	59,563

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

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	December 31, 2009		December 31, 2008		December 31, 2007	
	Shares	Amount	Shares	Amount	Shares	Amount
			(In thousands)			
Common Stock:						
Balance at Beginning of Period	89,459	$ 895	88,876	$ 889	32,008	$ 320
Exercise of Stock Options			478	5	250	3
Issuance of Common Stock, Net	26,569	266			56,618	566
Issuance of Restricted Stock	126	1	105	1		
Balance at End of Period	116,154	1,162	89,459	895	88,876	889
Capital in Excess of Par Value:						
Balance at Beginning of Period		1,785,462		1,731,882		243,157
Exercise of Stock Options				5,122		2,052
Issuance of Common Stock, Net		122,762				1,471,379
Issuance of Restricted Stock		(1)		(1)		
Compensation Expense Recognized		8,257		12,535		7,680
Adjustment due to Convertible Debt Accounting Change (See Note 1)				30,070		
Compensation Capitalized as part of the Purchase Price Allocation						3,778
Excess Tax Benefit From Stock-Based Arrangements		4,571		5,860		3,836
Other		(14)		(6)		
Balance at End of Period		1,921,037		1,785,462		1,731,882
Treasury Stock:						
Balance at Beginning of Period	(1,483)	(50,081)	(19)	(582)	(6)	(220)
Repurchase of Common Stock	(21)	(70)	(1,464)	(49,499)	(13)	(362)
Balance at End of Period	(1,504)	(50,151)	(1,483)	(50,081)	(19)	(582)

Accumulated Other Comprehensive Income (Loss):								
Balance at Beginning of Period			(14,932)			(8,117)			755
Change in Unrealized Gain (Loss) on Hedge Transactions, Net of Tax of $(4,932), $3,669 and $4,778, Respectively			9,159			(6,815)			(8,872)
Balance at End of Period, Net of Tax of $3,108, $8,040 and $4,371, Respectively			(5,773)			(14,932)			(8,117)
Retained Earnings (Deficit):									
Balance at Beginning of Period			(796,029)			287,361			150,839
Net Income (Loss)			(91,734)			(1,083,390)			136,522
Balance at End of Period			(887,763)			(796,029)			287,361
Total Stockholders Equity	114,650	$	978,512	87,976	$	925,315	88,857	$	2,011,433

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

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
Net Income (Loss)	$ (91,734)	$ (1,083,390)	$ 136,522
Other Comprehensive Income (Loss):			
Reclassification of (Gains) Losses, Net included in Net Income (Loss)	10,813	5,034	(897)
Other Comprehensive Losses, Net	(1,654)	(11,849)	(7,975)
Comprehensive Income (Loss)	$ (82,575)	$ (1,090,205)	$ 127,650

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

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2009	2008	2007
		(In thousands)	
Cash Flows from Operating Activities:			
Net Income (Loss)	$ (91,734)	$ (1,083,390)	$ 136,522
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:			
Depreciation and Amortization	201,421	192,918	109,064
Stock-Based Compensation Expense	8,257	12,535	7,680
Deferred Income Taxes	(89,295)	(118,685)	2,841
Provision for Doubtful Accounts Receivable	32,912	6,167	
Amortization of Original Issue Discount	4,120	4,292	
Amortization of Deferred Financing Fees	3,594	4,036	1,805
Non-Cash Loss on Derivatives	1,429		
Gain on Insurance Settlement	(8,700)		
Gain on Disposal of Assets	(970)	(3,029)	(4,491)
Expense of Credit Agreement Fees	15,073		
(Gain) Loss on Early Retirement of Debt, Net	(12,157)	(26,345)	2,182
Impairment of Goodwill		950,287	
Impairment of Property and Equipment	26,882	376,668	
Excess Tax Benefit from Stock-Based Arrangements	(4,571)	(5,860)	(3,836)
(Increase) Decrease in Operating Assets -			
Accounts Receivable	126,515	(78,510)	58,827
Insurance Claims Receivable	(402)	(840)	(13,565)
Prepaid Expenses and Other	39,889	53,635	9,263
Increase (Decrease) in Operating Liabilities -			
Accounts Payable	(37,256)	(5,482)	(6,794)
Insurance Notes Payable	(28,966)	(45,173)	(25,301)
Other Current Liabilities	(35,281)	17,125	15,239
Tax Sharing Agreement Payment		(4,000)	(116,003)
Other Liabilities	(11,841)	23,599	2,308
Net Cash Provided by Operating Activities	138,919	269,948	175,741
Cash Flows from Investing Activities:			
Acquisition of Business, Net of Cash Acquired			(728,396)
Acquisition of Assets		(320,839)	
Additions of Property and Equipment	(76,141)	(264,245)	(155,390)
Deferred Drydocking Expenditures	(15,646)	(17,269)	(20,772)
Investment in Marketable Securities			(151,675)
Proceeds from Sale of Marketable Securities		39,300	112,375
Insurance Proceeds Received	9,168	30,221	4,285
Proceeds from Sale of Assets, Net	25,767	17,045	109,745
(Increase) Decrease in Restricted Cash	(3,658)		4,821

Net Cash Used in Investing Activities	(60,510)	(515,787)	(825,007)
Cash Flow from Financing Activities:			
Short-term Debt Borrowings (Repayments), Net	(2,455)	2,455	(1,395)
Long-term Debt Borrowings	292,149	350,000	900,000
Long-term Debt Repayments	(403,648)	(121,427)	(97,750)
Redemption of 3.375% Convertible Senior Notes	(6,099)	(44,848)	
Common Stock Issuance (Repurchase)	89,600	(49,228)	
Proceeds from Exercise of Stock Options		5,127	2,054
Excess Tax Benefit from Stock-Based Arrangements	4,571	5,860	3,836
Payment of Debt Issuance Costs	(18,143)	(8,097)	(17,753)
Other	(11)		(46)
Net Cash Provided by (Used in) Financing Activities	(44,036)	139,842	788,946
Net Increase (Decrease) in Cash and Cash Equivalents	34,373	(105,997)	139,680
Cash and Cash Equivalents at Beginning of Period	106,455	212,452	72,772
Cash and Cash Equivalents at End of Period	$ 140,828	$ 106,455	$ 212,452

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

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Business and Significant Accounting Policies

Organization

Hercules Offshore, Inc., a Delaware corporation, and its majority owned subsidiaries (the Company) provides shallow-water drilling and marine services to the oil and natural gas exploration and production industry globally through its Domestic Offshore, International Offshore, Inland, Domestic Liftboats, International Liftboats and Delta Towing segments (See Note 17). At December 31, 2009, the Company owned a fleet of 30 jackup rigs, 17 barge rigs, three submersible rigs, one platform rig, a fleet of marine support vessels operated through Delta Towing, a wholly owned subsidiary, and 60 liftboat vessels and operated an additional five liftboat vessels owned by a third party. In addition, the Company owns four retired jackup rigs and eight retired inland barges, all located in the U.S. Gulf of Mexico, which are currently not expected to re-enter active service. In February 2010, the Company entered into an agreement to sell six of its retired barges for $3.0 million (See Notes 5, 17 and 21). The Company has operations in nine countries on three continents. The Company s diverse fleet is capable of providing services such as oil and gas exploration and development drilling, well service, platform inspection maintenance and decommissioning operations.

On July 11, 2007, the Company completed the acquisition of TODCO (See Note 4), a provider of contract oil and gas drilling services in the U.S. Gulf of Mexico and international locations. TODCO owned and operated 24 jackup rigs, 27 barge rigs, three submersible rigs, nine land rigs, one platform rig and a fleet of marine support vessels. During the fourth quarter of 2007, the Company sold the nine land rigs and related assets (See Note 5 and 6). In February 2008, the Company entered into a definitive agreement to purchase three jackup drilling rigs and related equipment for $320.0 million. The Company completed the purchase of the *Hercules 350* and the *Hercules 261* and related equipment during March 2008, while the purchase of the *Hercules 262* and related equipment was completed in May 2008 (See Note 4).

In December 2009, the Company entered into an agreement with First Energy Bank B.S.C. (MENAdrill) whereby it would market, manage and operate two Friede & Goldman Super M2 design new-build jackup drilling rigs each with a maximum water depth of 300 feet. The rigs are currently under construction and are scheduled to be delivered in the fourth quarter of 2010. The Company is actively marketing the rigs on an exclusive and worldwide basis.

In January 2010, the Company entered into an agreement with SKDP 1 Ltd., an affiliate of Skeie Drilling & Production ASA, to market, manage and operate an ultra high specification KFESL Class N new-build jackup drilling rig with a maximum water depth of 400 feet. The rig is currently under construction and is scheduled to be delivered in either the third or fourth quarter of 2010, depending upon the exercise of certain options available to the owner. The agreement is limited to a specified opportunity in the Middle East.

The Company had previously entered into similar agreements with Mosvold Middle East Jackup I Ltd. and Mosvold Middle East Jackup II Ltd. to market, manage and operate two Friede & Goldman Super M2 design new-build jackup rigs. The Company later terminated these agreements by mutual agreement due to uncertainties in the timing of the delivery of the rigs and disputes between the owner and the builder of the rigs.

Adjustment for Retrospective Application of FSP APB 14-1, Primarily Codified into Financial Accounting Standards Board s (FASB) Codification Topic 470-20, Debt Debt with Conversion and Other Options

The Company has adjusted the financial statements as of and for the year ended December 31, 2008 to reflect its adoption of the FASB Codification Topic 470-20, *Debt Debt with Conversion and Other Options*, which clarifies the accounting for convertible debt instruments that may be settled in cash (including partial cash settlement) upon conversion. It requires issuers to account separately for the liability and equity components of certain convertible debt instruments in a manner that reflects the issuer s nonconvertible debt (unsecured debt) borrowing rate when interest cost is recognized. It also requires bifurcation of a component

Table of Contents

HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of the debt, classification of that component in equity and the accretion of the resulting discount on the debt to be recognized as part of interest expense in the Company s consolidated statement of operations. The standard became effective as of January 1, 2009 and it required retrospective application to the terms of instruments as they existed for all periods presented. This adoption affects the accounting for the Company s 3.375 percent Convertible Senior Notes due 2038 issued in 2008 (3.375% Convertible Senior Notes). The retrospective application of FASB Codification Topic 470-20, *Debt Debt with Conversion and Other Options* only affects 2008 as no other convertible notes were issued prior to 2008.

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. All intercompany account balances and transactions have been eliminated.

Common Stock Offering

In September 2009, the Company raised approximately $82.3 million in net proceeds from an underwritten public offering of 17,500,000 shares of its common stock. In addition, on October 9, 2009, the Company sold an additional 1,313,590 shares of its common stock pursuant to the partial exercise of the underwriters over-allotment option and raised an additional $6.3 million in net proceeds. In October 2009, the Company used 50% of the net proceeds from these sales of common stock to repay a portion of its outstanding indebtedness under its term loan facility, and may use some or all of the remaining proceeds to repay additional indebtedness.

Reclassifications

Certain reclassifications have been made to conform prior year financial information to the current period presentation including reclassifying the assets associated with the *Hercules 100* and *Hercules 110* as Assets Held for Sale which were subsequently sold in August 2009 (See Notes 2, 5 and 17).