

HERCULES OFFSHORE, INC.  
Form 10-K  
March 01, 2013  
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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, 2012  
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)

Registrant's telephone number, including area code:

(713) 350-5100

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

Title of Each Class

Common Stock, \$0.01 par value per share

Rights to Purchase Preferred Stock

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  No

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

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

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

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

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

Large accelerated filer  Accelerated filer  Non-accelerated filer  Smaller reporting company

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(Do not check if a smaller reporting company)

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

The aggregate market value of the registrant's common stock held by non-affiliates as of June 30, 2012, based on the closing price on the NASDAQ Global Select Market on such date, was approximately \$476 million. As of such date, the registrant's directors and executive officers and Seahawk Drilling, Inc. were considered affiliates of the registrant for this purpose.

As of February 21, 2013, there were 158,755,820 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 15, 2013 are incorporated by reference into Part III of this report.

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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](http://www.herculesoffshore.com).

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 21, 2013, we owned a fleet of 37 jackup rigs, thirteen barge rigs, 58 liftboat vessels and operated an additional five liftboat vessels owned by a third party. 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 several key shallow-water provinces around the world.

In March 2012, we acquired an offshore jackup drilling rig, Hercules 266, for \$40.0 million. We entered into a three-year drilling contract with Saudi Aramco for the use of this rig with Saudi Aramco having an option to extend the term for an additional one-year period. This rig is currently undergoing upgrades and other contract specific refurbishments and we expect the rig to commence work under the contract in the second quarter of 2013.

During April 2012, the Kingfish, a 230 class liftboat, began its mobilization from the U.S. Gulf of Mexico to the Middle East, where it underwent upgrades prior to becoming reactivated. The vessel commenced work in November 2012.

During November 2012, the decision was made to reactivate one of our previously cold stacked rigs, Hercules 209. Hercules 209 is currently in the shipyard undergoing repairs and upgrades for reactivation and is expected to be available for work in the second quarter of 2013.

As of February 21, 2013, our business segments include the following:

Domestic Offshore — includes 29 jackup rigs in the U.S. Gulf of Mexico that can drill in maximum water depths ranging from 85 to 350 feet. Nineteen of the jackup rigs are either under contract or available for contracts and ten are cold stacked.

International Offshore — includes eight jackup rigs outside of the U.S. Gulf of Mexico. We have three jackup rigs contracted offshore in Saudi Arabia, one jackup rig contracted offshore in Myanmar and one jackup rig contracted offshore in Cameroon. In addition, we have one jackup rig warm stacked and one jackup rig cold stacked in Bahrain as well as one jackup rig cold stacked in Malaysia. In addition to owning and operating our own rigs, we have the Construction Management Agreement and the Services Agreement with Discovery Offshore S.A. (“Discovery Offshore”) with respect to each of its two rigs.

Inland — includes a fleet of three conventional and ten 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 under contract or available and ten are cold stacked.

Domestic Liftboats — includes 39 liftboats in the U.S. Gulf of Mexico. Twenty-nine are operating or available for contracts and ten are cold stacked.

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

RECENT DEVELOPMENTS

In February 2013, we entered into a definitive agreement to acquire the offshore drilling rig Ben Avon from a subsidiary of KCA Deutag. The purchase price was \$55.0 million in cash and we expect the acquisition to close in late March 2013. In addition, we signed a three-year rig commitment with Cabinda Gulf Oil Company Limited for use of

the Ben Avon. We expect the rig to commence work in the second quarter of 2013.

In February 2013, we entered into a definitive agreement to acquire the liftboat Titan 2, a 280 class vessel, from a subsidiary of KS Energy Ltd. The purchase price was \$42.0 million in cash and we expect the acquisition to close in early March 2013. The liftboat is currently located in Limbe, Cameroon. In addition, we signed a Letter of Intent for a short term commitment to use the Titan 2 and we expect the vessel to commence work shortly after the acquisition closes.

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**Our Fleet**

Our jackup 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 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. 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.

**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 position themselves more quickly on the worksite and more easily move on and off location than independent leg rigs.

Twenty-eight of our jackup rigs are mat-supported and nine are independent leg rigs.

Thirty-one 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. Six rigs have a slot-type design, which requires drilling operations to take place through a slot in the hull. Slot-type rigs are 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 21, 2013, twenty-four of our jackup rigs were under contract ranging in duration from well-to-well to three years. 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.

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The following table contains information regarding our jackup rig fleet as of February 21, 2013.

Rig Name	Type	Year Built/ Upgraded(a)	Maximum/ Minimum Water Depth Rating (Feet)	Rated Drilling Depth(b) (Feet)	Location	Status(c)
Hercules 85	ILS	1982	85/9	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 153	MC	1980/2007	150/22	25,000	U.S. GOM	Cold Stacked
Hercules 156	ILC	1983	150/14	20,000	Bahrain	Cold 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 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	U.S. GOM	Contracted
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	Myanmar	Contracted
Hercules 209(e)	MC	1981/2013	200/23	20,000	U.S. GOM	Shipyard
Hercules 211	MC	1980	200/23	18,000(f)	U.S. GOM	Cold Stacked
Hercules 212	MC	1982	200/23	20,000	U.S. GOM	Contracted
Hercules 213	MC	1981/2002	200/23	20,000	U.S. GOM	Contracted
Hercules 214	MC	1982	200/23	20,000	U.S. GOM	Contracted
Hercules 250	MS	1974	250/24	20,000	U.S. GOM	Cold Stacked
Hercules 251	MS	1978	250/24	20,000	U.S. GOM	Contracted
Hercules 253	MS	1982	250/24	20,000	U.S. GOM	Contracted
Hercules 258	MS	1979/2008	250/24	20,000	Malaysia	Cold Stacked
Hercules 260	ILC	1979/2008	250/12	20,000	Cameroon	Shipyard
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 263	MC	1982/2002	250/23	20,000	U.S. GOM	Contracted
Hercules 264	MC	1976/1999	250/23	25,000	U.S. GOM	Contracted
Hercules 265	MC	1982	250/25	20,000	U.S. GOM	Contracted
Hercules 266	ILC	1978/2013	250/12	20,000	Saudi Arabia	Shipyard
Hercules 300	MC	1974/1999	300/25	25,000	U.S. GOM	Contracted
Hercules 350	ILC	1982	350/16	25,000	U.S. GOM	Contracted
Hercules 2002	MC	1982	200/23	20,000	U.S. GOM	Cold Stacked
Hercules 2003	MC	1981	200/23	20,000	U.S. GOM	Cold Stacked
Hercules 2500	MS	1981/1996	250/24	20,000	U.S. GOM	Cold Stacked

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

(b) 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.



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Rigs designated as “Contracted” are under contract while rigs described as “Warm Stacked” are actively marketed and 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. Rigs described as “Shipyard” are undergoing maintenance, repairs or upgrades and may or may not be actively marketed depending on the length of stay in the shipyard.

(d) This rig is currently unable to operate in the U.S. Gulf of Mexico due to United States Department of Transportation Maritime Administration (“MARAD”) restrictions.

(e) This rig is undergoing reactivation activities.

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.

**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 13 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.

The following table contains information regarding our barge drilling rig fleet as of February 21, 2013.

Rig Name	Type	Year Built/ Upgraded(a)	Horsepower Rating	Rated Drilling Depth(b) (Feet)	Location	Status(c)
1	Conv.	1980	2,000	20,000	U.S. GOM	Cold Stacked
11	Conv.	1982	3,000	30,000	U.S. GOM	Cold Stacked
17	Posted	1981	3,000	30,000	U.S. GOM	Ready Stacked
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
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	Ready Stacked
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) Dates shown are the original date the rig was built and the date of the most recent upgrade and/or major refurbishment, if any.

(b) 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.

Rigs designated as “Contracted” are under contract. Rigs described as “Ready Stacked” are not under contract but generally are 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.

**Liftboats**

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. 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;

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well plug and abandonment; and  
 pipeline installation and maintenance.

Our liftboats are ideal working platforms providing 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 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. Our liftboats in the U.S. Gulf of Mexico range in leg lengths up to 229 feet, which allows us to service the majority of the shallow-water offshore infrastructure 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 21, 2013, we owned 39 liftboats operating in the U.S. Gulf of Mexico, sixteen liftboats operating in West Africa, and three 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 21, 2013.

Liftboat Name(1)	Year Built/ Upgraded(2)	Leg Length (Feet)	Deck Area (Square feet)	Maximum Deck Load (Pounds)	Location	Gross Tonnage
Whale Shark(3)	2005/2009	260	8,170	1,010,000	U.A.E.	1,142
Tiger Shark(4)	2001	230	5,300	1,000,000	Nigeria	469
Kingfish(3)	1996/2012	229	5,000	500,000	U.A.E	1,312
Man-O-War(4)	1996	229	5,000	500,000	U.S. GOM	188
Wahoo(4)	1981	215	4,525	500,000	U.S. GOM	491
Blue Shark(3)	1981	215	3,800	400,000	Nigeria	1,182
Amberjack(3)	1981	205	3,800	500,000	U.A.E.	417
Bullshark(4)	1998	200	7,000	1,000,000	U.S. GOM	859
Creole Fish(4)	2001	200	5,000	798,000	Nigeria	192
Cutlassfish(4)	2006	200	5,000	798,000	Nigeria	183
Black Jack(3)	1997/2008	200	4,000	480,000	Nigeria	777
Swordfish(4)	2000	190	4,000	700,000	U.S. GOM	189
Leatherjack(4)	1998	175	3,215	575,850	U.S. GOM	168
Oilfish(3)	1996	170	3,200	590,000	Nigeria	495
Manta Ray(4)	1981	150	2,400	200,000	U.S. GOM	194
Seabass(4)	1983	150	2,600	200,000	U.S. GOM	186
F.J. Leleux(5)	1981	150	2,600	200,000	Nigeria	407
Black Marlin(3)	1984	150	2,600	200,000	Nigeria	407
Hammerhead(4)	1980	145	1,648	150,000	U.S. GOM	178
Pilotfish(3)	1990	145	2,400	175,000	Nigeria	292
Rudderfish(3)	1991	145	3,000	100,000	Nigeria	309
Blue Runner(4)	1980	140	3,400	300,000	U.S. GOM	174
Rainbow Runner(4)	1981	140	3,400	300,000	U.S. GOM	174
Pompano(4)	1981	130	1,864	100,000	U.S. GOM	196
Sandshark(4)	1982	130	1,940	150,000	U.S. GOM	196
Stingray(4)	1979	130	2,266	150,000	U.S. GOM	99

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Albacore(4)	1985	130	1,764	150,000	U.S. GOM	171
Moray(4)	1980	130	1,824	130,000	U.S. GOM	178

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Liftboat Name(1)	Year Built/ Upgraded(2)	Leg Length (Feet)	Deck Area (Square feet)	Maximum Deck Load (Pounds)	Location	Gross Tonnage
Skipfish(4)	1985	130	1,116	110,000	U.S. GOM	91
Sailfish(4)	1982	130	1,764	137,500	U.S. GOM	179
Mahi Mahi(4)	1980	130	1,710	142,000	U.S. GOM	99
Triggerfish(4)	2001	130	2,400	150,000	U.S. GOM	195
Scamp(3)	1984	130	2,400	150,000	Nigeria	195
Rockfish(4)	1981	125	1,728	150,000	U.S. GOM	192
Gar(4)	1978	120	2,100	150,000	U.S. GOM	98
Grouper(4)	1979	120	2,100	150,000	U.S. GOM	97
Sea Robin(4)	1984	120	1,507	110,000	U.S. GOM	98
Tilapia(4)	1976	120	1,280	110,000	U.S. GOM	97
Charlie Cobb(5)	1980	120	2,000	100,000	Nigeria	229
Durwood Speed(5)	1979	120	2,000	100,000	Nigeria	210
James Choat(5)	1980	120	2,000	100,000	Nigeria	210
Solefish(3)	1978	120	2,000	100,000	Nigeria	229
Tigerfish(3)	1980	120	2,000	100,000	Nigeria	210
Zoal Albrecht(5)	1982	120	2,000	100,000	Nigeria	213
Barracuda(4)	1979	105	1,648	110,000	U.S. GOM	93
Carp(4)	1978	105	1,648	110,000	U.S. GOM	98
Cobia (4)	1978	105	1,648	110,000	U.S. GOM	94
Dolphin (4)	1980	105	1,648	110,000	U.S. GOM	97
Herring(4)	1979	105	1,648	110,000	U.S. GOM	97
Marlin(4)	1979	105	1,648	110,000	U.S. GOM	97
Corina(4)	1974	105	953	100,000	U.S. GOM	98
Pike(4)	1980	105	1,360	130,000	U.S. GOM	92
Remora(4)	1976	105	1,179	100,000	U.S. GOM	94
Wolffish(4)	1977	105	1,044	100,000	U.S. GOM	99
Seabream(4)	1980	105	1,140	100,000	U.S. GOM	92
Sea Trout(4)	1978	105	1,500	100,000	U.S. GOM	97
Tarpon(4)	1979	105	1,648	110,000	U.S. GOM	97
Palometa(4)	1972	105	780	100,000	U.S. GOM	99
Jackfish(4)	1978	105	1,648	110,000	U.S. GOM	99
Bonefish(3)	1978	105	1,344	90,000	Nigeria	97
Croaker(3)	1976	105	1,344	72,000	Nigeria	82
Gemfish(3)	1978	105	2,000	100,000	Nigeria	223
Tapertail(3)	1979	105	1,392	110,000	Nigeria	100

(1) The Skipfish, Mahi Mahi, Corina, Remora, Wolffish, Palometa, Bonefish, Croaker, Barracuda, Pike, Sea Trout and Seabream are currently cold stacked. All other liftboats are either available or operating.

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

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

(4) 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.

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



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## 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. As a result, these competitors may have a better ability 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 certain 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. Sales to customers exceeding 10 percent or more of our total revenue in any of the past three years are as follows:

	Year Ended			
	December 31,			
	2012	2011	2010	
Chevron Corporation(a)	17	% 25	% 17	%
Saudi Aramco(b)	6	13	14	
Oil and Natural Gas Corporation Limited(b)	—	9	20	

(a) Revenue included in our Domestic Offshore, International Offshore, Domestic Liftboats and International Liftboats segments.

(b) Revenue included in our International Offshore segment.

## 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 historically 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.

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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**

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, less any penalties or reductions in dayrate for late delivery or non-compliance with contractual obligations. Backlog excludes revenue for management agreements, mobilization, demobilization, contract preparation and customer reimbursables. The amount of actual revenue earned and the actual periods during which revenue is earned will be different than the backlog disclosed or expected due to various factors. Downtime 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), 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. The following table reflects the amount of our contract backlog by year as of February 21, 2013, which excludes the three-year rig commitment with Cabinda Gulf Oil Company Limited for use of the Ben Avon, as this acquisition has not yet closed:

	For the Years Ending December 31,				
	Total	2013	2014	2015	Thereafter
	(in thousands)				
Domestic Offshore	\$370,696	\$334,951	\$35,745	\$—	\$—
International Offshore	268,492	126,683	102,652	39,157	—
Inland	818	818	—	—	—
International Liftboats	42,151	16,157	24,940	1,054	—
Total	\$682,157	\$478,609	\$163,337	\$40,211	\$—

**Employees**

As of December 31, 2012, we had approximately 2,600 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 employer's liability, general liability, vessel pollution and other coverages.

Our primary marine package provides for hull and machinery coverage for substantially all of our rigs and liftboats up to a scheduled value of each asset. The total maximum amount of coverage for these assets is \$1.6 billion. The marine package includes protection and indemnity and maritime employer's liability coverage for marine crew personal injury and death and certain operational liabilities, with primary coverage (or self-insured retention for maritime employer's liability coverage) of \$5.0 million per occurrence with excess liability coverage up to \$200.0 million. The marine package policy also includes coverage for personal injury and death of third parties with primary and excess coverage of \$25.0 million per occurrence with additional excess liability coverage up to \$200.0 million, subject to a \$250,000 per-occurrence deductible. The marine package also provides coverage for cargo and charterer's legal liability. The marine package includes limitations for coverage for losses caused in U.S. Gulf of Mexico named windstorms, including an annual aggregate limit of liability of \$75.0 million for property damage and removal of wreck liability coverage. We also procured an additional \$75.0 million excess policy for removal of wreck and certain third-party liabilities incurred in U.S. Gulf of Mexico named windstorms. Deductibles for events that are not caused by a U.S. Gulf of Mexico named windstorm are 12.5% of the insured drilling rig values per occurrence, subject to a minimum of

\$1.0 million, and \$1.0 million per occurrence for liftboats. The deductible for drilling rigs and liftboats in a U.S. Gulf of Mexico named windstorm event is \$25.0 million. Vessel pollution is covered under a Water Quality Insurance Syndicate policy (“WQIS Policy”) providing limits as required by applicable law, including the Oil Pollution Act of 1990. The WQIS Policy covers pollution emanating from our vessels and drilling rigs, with primary limits of \$5.0 million (inclusive of a \$3.0 million per-occurrence deductible) and excess liability coverage up to \$200.0 million.

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Control-of-well events generally include an unintended flow from the well that cannot be contained by equipment on site (e.g., a blow-out preventer), by increasing the weight of the drilling fluid, or that does not naturally close itself off through what is typically described as "bridging over". We carry a contractor's extra expense policy with \$25.0 million primary liability coverage for well control costs, expenses incurred to redrill wild or lost wells and pollution, with excess liability coverage up to \$200.0 million for pollution liability that is covered in the primary policy. The policies are subject to exclusions, limitations, deductibles, self-insured retention and other conditions. In addition to the marine package, we have separate policies providing coverage for onshore foreign and domestic general liability, employer's liability, auto liability and non-owned aircraft liability, with customary deductibles and coverage. Our policy, which we renew annually, expires in April 2013.

Our drilling contracts provide for varying levels of indemnification from our customers and in most cases, may require us to indemnify our customers for certain liabilities. Under our drilling contracts, liability with respect to personnel and property is customarily assigned on a "knock-for-knock" basis, which means that we and our customers assume liability for our respective personnel and property, regardless of how the loss or damage to the personnel and property may be caused. Our customers typically assume responsibility for and agree to indemnify us from any loss or liability resulting from pollution or contamination, including clean-up and removal and third-party damages arising from operations under the contract and originating below the surface of the water, including as a result of blow-outs or cratering of the well ("Blowout Liability"). The customer's assumption for Blowout Liability may, in certain circumstances, be limited or could be determined to be unenforceable in the event of our gross negligence, willful misconduct or other egregious conduct. In addition, we may not be indemnified for statutory penalties and punitive damages relating to such pollution or contamination events. We generally indemnify the customer for the consequences of spills of industrial waste or other liquids originating solely above the surface of the water and emanating from our rigs or vessels.

We are self-insured for the deductible portion of our insurance coverage. Management believes adequate accruals have been made on known and estimated exposures up to the deductible portion of our insurance coverage. Management believes that claims and liabilities in excess of the amounts accrued are adequately insured. 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. In addition, there is no assurance of renewal or the ability to obtain coverage acceptable to us.

### Insurance Claims Settlement

In September 2011, we were conducting a required annual spud can inspection on Hercules 185 in protected waters offshore Angola. While conducting the inspection, it was determined that the spud can on the starboard leg had detached from the leg. Subsequently, additional leg damage was identified. The rig underwent repairs related to this damage and was mobilized back to Angola. During the return mobilization from the U.S. Gulf of Mexico to Angola, Hercules 185 experienced additional damage to its legs. We conducted a survey of the rig's legs above and below the water line and discovered extensive damage to various portions of the rig's legs. In June 2012, we determined that it was unfeasible to repair the damage and return the rig to service and recorded an impairment charge to write the rig down to salvage value. We and our insurance underwriters reached a global settlement in September 2012, agreeing that Hercules 185 should be considered a constructive total loss. From this settlement, we received total insurance proceeds of \$41.0 million for the rig, including \$7.5 million received in June 2012 for its earlier claim relating to previous leg damage to the rig. These proceeds generated a gain on insurance settlement of \$27.3 million which is included in Operating Expenses on the Consolidated Statements of Operations for the year ended December 31, 2012. As part of the settlement, we agreed to transport and attempt to sell the rig, which entitled us to the first \$1.5 million in proceeds from such sale and any sale proceeds in excess of \$1.5 million being split seventy-five percent to the underwriters and twenty-five percent to us.

### Regulation

Our operations are affected in varying degrees by federal, state, local and foreign and/or international governmental laws and regulations regarding the discharge of materials into the environment or otherwise relating to environmental protection. 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

subject to the jurisdiction of the U.S. Coast Guard (“Coast Guard”), the National Transportation Safety Board (“NTSB”), the U.S. Customs and Border Protection (“CBP”), the Department of Interior, the Bureau of Ocean Energy Management (“BOEM”) and the Bureau of Safety and Environmental Enforcement (“BSEE”), as well as classification societies such as the American Bureau of Shipping (“ABS”). The Coast Guard and the NTSB set safety standards and are authorized to investigate vessel accidents and recommend improved safety standards, and the CBP is authorized to inspect vessels at will. Coast Guard regulations also require annual inspections and periodic drydock inspections or special examinations of our vessels.

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For instance, the Coast Guard issued a Policy Letter in July 2011 that provides for more frequent inspections of foreign flagged Mobile Offshore Drilling Units (“MODUs”) that operate on the U.S. Outer Continental Shelf (“OCS”). The Coast Guard will make determinations to conduct more frequent inspections of foreign flagged MODUs in accordance with its Mobile Offshore Drilling Unit Safety and Environmental Protection Compliance Targeting Matrix. We may be subject to increased costs and potential downtime for certain of our rigs operating on the OCS if such rigs are determined by the Coast Guard to need additional oversight and inspection under this Policy Letter.

In addition to this Coast Guard Policy Letter, in November 2011, the BSEE announced a change in its enforcement policies in the aftermath of the Macondo well blowout in April 2010, pursuant to which the agency has extended its regulatory enforcement reach to include contractors as well as offshore lease operators. Consequently, the BSEE may elect to hold contractors, including drilling contractors, liable for alleged violations of law arising in the BSEE’s jurisdictional area. In August 2012, the BSEE issued an Interim Policy Letter that established the parameters by which BSEE will issue incidents of noncompliance to drilling contractors for serious violations of BSEE regulations. Implementation of this announced change in enforcement policy by the BSEE could subject us to added liabilities, including sanctions and penalties, as well as increased costs arising from contractual arrangements in master services agreements that failed to take into account such change in enforcement policy with respect to our operations in the U.S. Gulf of Mexico, which may have an adverse effect on our business and results of operations.

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, our operations are subject to federal and state laws and regulations that require us to obtain and maintain specified permits or governmental approvals; control the discharge of materials into the environment; remove and cleanup materials that may harm the environment; or otherwise comply with the protection of the environment. For example, as an operator of mobile offshore units in navigable U.S. waters including the OCS, 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. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions restricting some or all of our activities in the affected areas. Laws and regulations protecting the environment have become more stringent over time 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 legal requirements or the adoption of new or more stringent legal 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, as amended, 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 discharge activities occur. Offshore facilities must also prepare plans addressing spill prevention, control and countermeasures. In addition, while operators of vessels visiting U.S. ports historically have been excluded from obtaining permits for the discharge of ballast water and other substances incidental to the normal operation of the vessels because of an exemption under the Clean Water Act, that exemption was vacated, effective February 6, 2009. In place of the former Clean Water Act exemption, the EPA adopted a Vessel General Permit, effective December 19, 2008, that required subject vessel operators, including us, to obtain a Vessel General Permit for all of our covered vessels by February 6, 2009. We have obtained the necessary Vessel General Permit for all of our vessels to which this permitting program applies. The current Vessel General Permit expires December 19, 2013 and EPA has released a new draft permit which is expected to be issued in March 2013. In addition to the EPA’s issuance of the Vessel General Permit, some states are, and other states are considering, regulating ballast water discharges. Violations of monitoring, reporting and permitting requirements associated with applicable ballast water discharge permitting programs or other regulatory initiatives may result in the imposition of civil and criminal penalties. Moreover, we have incurred added costs to comply with legal requirements under the Vessel General Permit and may continue to incur further costs as other legal

requirements under federal and state ballast water discharge permit programs are adopted and implemented, but we do not believe that such compliance efforts will have a material adverse effect on our results of operations or financial position.

The U.S. Oil Pollution Act of 1990 (“OPA”), as amended, and related regulations impose a variety of requirements on “responsible parties” related to the prevention and/or reporting of oil spills and liability for damages resulting from such spills in waters off the U.S. A “responsible party” includes the owner or operator of an onshore facility, pipeline or vessel or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages. Under OPA, as amended by the Coast Guard and Maritime Transportation Act of 2006, “tank vessels” of over 3,000 gross tons that carry oil or other hazardous materials in bulk as cargo, are subject to liability limits of (i) for a single-hulled vessel, the greater of \$3,200 per gross ton or \$23.5 million or (ii) for a

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tank vessel other than a single-hulled vessel, the greater of \$2,000 per gross ton or \$17.1 million. “Tank vessels” of 3,000 gross tons or less are subject to liability limits of (i) for a single-hulled vessel, the greater of \$3,200 per gross ton or \$6.4 million or (ii) for a tank vessel other than a single-hulled vessel, the greater of \$2,000 per gross ton or \$4.3 million. For any vessels other than “tank vessels” that are subject to OPA, the liability limits are the greater of \$1,000 per gross ton or \$854,400. Few defenses exist to the liability imposed by OPA and the liability could be substantial. Moreover, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, the liability limits likewise do not apply and certain defenses may not be available. In addition, OPA imposes on responsible parties the need for proof of financial responsibility to cover at least some costs in a potential spill. As required, we have provided satisfactory evidence of financial responsibility to the Coast Guard for all of our vessels subject to such requirements.

The U.S. Outer Continental Shelf Lands Act, as amended, authorizes regulations relating to safety and environmental protection applicable to lessees and permittees operating on the OCS. 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 OCS 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, as amended, also known as CERCLA or the “Superfund” law, imposes liability without regard to fault or the legality of the original conduct on certain 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 entities 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. We generate wastes in the course of our routine operations that may be classified as hazardous substances.

The U.S. Resource Conservation and Recovery Act, as amended, regulates the generation, transportation, storage, treatment and disposal of onshore hazardous and non-hazardous wastes and requires states to develop programs to ensure the safe disposal of wastes. We generate nonhazardous wastes and small quantities of hazardous wastes in connection with routine operations. We believe that all of the wastes that we generate are handled in compliance in all material respects with the Resource Conservation and Recovery Act and analogous state laws.

In recent years, a variety of initiatives intended to enhance vessel security were adopted to address terrorism risks, including the 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 of our 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.

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The United States is one of approximately 170 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 entered into force on May 19, 2005, and applies to all ships, fixed and floating drilling rigs and other floating platforms. 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 previously. Annex VI came into force in the United States on January 8, 2009. Moreover, on July 1, 2010, amendments to Annex VI to the MARPOL Convention took effect requiring the imposition of progressively stricter limitations on sulfur emissions from ships. As a result, limitations imposed on sulfur emissions will require that fuels of vessels in covered Emission Control Areas (“ECAs”) contain no more than 1% sulfur. In August 2012, the North American ECA became enforceable. The North American ECA includes areas subject to the exclusive sovereignty of the United States and extends up to 200 nautical miles from the coasts of the United States, which area includes parts of the U.S. Gulf of Mexico. Consequently, beginning on January 1, 2012, limits on marine fuel used to power ships in non-ECA areas were capped at 3.5% sulfur and, in August 2012, when the North American ECA became effective, the sulfur limit in marine fuel was capped at 1%, which is the capped amount for all other ECA areas since July 1, 2010. These capped amounts will then decrease progressively until they reach 0.5% by January 1, 2020 for non-ECA areas and 0.1% by January 1, 2015 for ECA areas, including the North American ECA. The amendments also establish new tiers of stringent nitrogen oxide emissions standards for new marine engines, depending on their date of installation. Our operation of vessels in international waters, outside of the North American ECA, are 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 that compliance with MARPOL or Annex VI to MARPOL, whether within the North American ECA or beyond, will have a material adverse effect on our results of operations or financial position.

In response to the Macondo well blowout incident in April 2010, the U.S. Department of Interior, initially through the U.S. Bureau of Ocean Energy Management, Regulation and Enforcement (“BOEMRE”) and, upon dissolution of the BOEMRE effective October 1, 2011, through the BOEM and BSEE, has undertaken an aggressive overhaul of the offshore oil and natural gas regulatory process that has significantly impacted oil and gas development in the U.S. Gulf of Mexico. From time to time, new rules, regulations and requirements have been proposed and implemented by BOEM, BSEE or the United States Congress that materially limit or prohibit, and increase the cost of, offshore drilling in the U.S. Gulf of Mexico. These new rules, regulations and requirements include the moratorium on shallow-water drilling that was lifted in May 2010, but which resulted in a significant delay in permits being issued in the U.S. Gulf of Mexico, the adoption of new safety requirements and policies relating to the approval of drilling permits in the U.S. Gulf of Mexico, restrictions on oil and gas development and production activities in the U.S. Gulf of Mexico, and the promulgation of numerous Notices to Lessees that have impacted and may continue to impact our operations. In addition to these rules, regulations and requirements, the federal government is considering new legislation that could impose additional equipment and safety requirements on operators and drilling contractors in the U.S. Gulf of Mexico, as well as regulations relating to the protection of the environment, all of which could materially adversely affect our financial condition and results of operations.

Greenhouse gas emissions have increasingly become the subject of international, national, regional, state and local attention. Cap and trade initiatives to limit greenhouse gas emissions have been introduced in the European Union. Similarly, numerous bills related to climate change have been introduced in the U.S. Congress, which could adversely impact most industries. In addition, future regulation of greenhouse gas could occur pursuant to future treaty obligations, statutory or regulatory changes or new climate change legislation in the jurisdictions in which we operate. It is uncertain whether any of these initiatives will be implemented. However, based on published media reports, we believe that it is not reasonably likely that recently considered federal legislative initiatives in the U.S. will be adopted and implemented without substantial modification. Restrictions on greenhouse gas emissions or other related legislative or regulatory enactments could have an effect in those industries that use significant amounts of petroleum products, which could potentially result in a reduction in demand for petroleum products and, consequently and indirectly, our offshore support services. We are currently unable to predict the manner or extent of any such effect. Furthermore, one of the asserted long-term physical effects of climate change may be an increase in the severity and frequency of adverse weather conditions, such as hurricanes, which may increase our insurance costs or risk retention, limit insurance availability or reduce the areas in which, or the number of days during which,

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our customers would contract for our vessels in general and in the U.S. Gulf of Mexico in particular. We are currently unable to predict the manner or extent of any such effect.

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](http://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](http://www.sec.gov). Information contained on our website is not part of this annual report.

### Segment and Geographic Information

Information with respect to revenue, operating income and total assets attributable to our segments and revenue and long-lived assets by geographic areas of operations is presented in Note 16 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. 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. Reductions in capital expenditures of our customers reduce rig utilization and day rates. Crude oil and condensates are representing a larger proportion of overall production in the U.S. GOM, however, a majority of the production remains natural gas. Oil and natural gas prices are extremely volatile and 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;
- advances in drilling, 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;

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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 (including the recent tensions between the international community and Iran), North Africa, 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 are increasingly common occurrences.

While economic conditions continue to improve, reduced demand for drilling and liftboat services could materially erode dayrates and utilization rates for our units, which could adversely affect our financial condition and results of operations. Continued hostilities in the Middle East, North Africa, and West Africa and the occurrence or threat of terrorist attacks against the United States or other countries could negatively impact the economies of the United States and other countries where we operate. Another decline in the economy could result in a decrease in energy consumption, which in turn would cause our revenue and margins to decline and limit our future growth prospects. The offshore service industry is highly cyclical and experiences periods of low demand and low dayrates. The volatility of the industry, coupled with our short-term contracts, has in the past resulted and could again 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 intensify the competition in the industry and often result in rigs or liftboats being idle for long periods of time. As a result of the cyclicity of our industry, we expect our results of operations to be volatile and to decrease during market declines such as the recession we recently experienced.

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 carrying value. 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, 2012, we had total outstanding debt of approximately \$865.1 million. This debt represented approximately 49% of our total book capitalization. As of December 31, 2012, we had \$74.0 million of available capacity under our revolving credit facility, after the commitment of \$1.0 million for letters of credit issued under it. We may borrow under our revolving credit facility to fund working capital or other needs in the near term up to the remaining availability, subject to our compliance with financial covenants. 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 our existing credit facility or notes 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 to payments of interest on our debt;

we may be exposed to risks inherent in interest rate fluctuations on borrowings under our credit facility which could 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 convertible notes issued by us in June 2008, the senior notes issued by us in October 2009, the senior secured notes issued by us in April 2012 and the

senior notes issued by us in April 2012, and to fund planned capital expenditures will depend on our ability to generate cash in the future,

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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.

Our debt instruments impose significant additional costs and operating and financial restrictions on us, which may prevent us from capitalizing on business opportunities and taking certain actions.

Our debt instruments impose 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;
- 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.

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.

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

Our revolving credit facility includes a financial covenant that will be tested if borrowings or letters of credit exceed \$10.0 million. If we trigger the conditions requiring testing, our ability to comply with this financial covenant and restrictions can be affected by events beyond our control. Reduced activity levels in the oil and natural gas industry could adversely impact our ability to comply with such covenants in the future. Our failure to comply with such covenant would result in an event of default under the revolving credit facility. 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 revolving credit facility, the 3.375% Convertible Senior Notes due 2038, the 10.5% Senior Notes due 2017, the 7.125% Senior Secured Notes due 2017 and the 10.25% Senior Notes due 2019, and in foreclosure of liens on our assets. As of December 31, 2012, we were not required to test the financial covenant under our revolving credit facility.

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 and excess capacity puts downward pressure on 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 reactivated.

Several of our competitors also are incorporated in other jurisdictions outside the United States, which provides them with significant tax advantages that are not available to us as a U.S. company and, as a result, may materially impair

our ability to compete with them for many projects that would be beneficial to our company.

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Global financial and economic circumstances may have impacts on our business and financial condition that we cannot predict, and may limit our ability to finance our business and refinance our debt at a reasonable cost of capital. We may face challenges if conditions in the financial markets are inadequate to finance our activities and pay or refinance our debt as it comes due at a reasonable cost. Continuing concerns over the worldwide economic outlook, the availability and costs of credit, and the sovereign debt crisis have contributed to increased volatility in the global financial markets and commodity prices and diminished expectations for the global economy. These conditions could make it more difficult for us to access capital on reasonable terms and to refinance our debt at reasonable costs. 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 the covenant under our revolving credit facility. Adequate sources of capital funding may not be available when needed or may not be available on acceptable terms. In addition, under the terms of our revolving credit facility, 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 assets, 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 in 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 environment, 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 sales on acceptable terms.

Our customer contracts are generally short term, and we will experience reduced profitability if our customers reduce activity levels, terminate or seek to renegotiate 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, if we are unable to secure new contracts on substantially similar terms, especially those contracts in our International Offshore segment, or if contracts are suspended for an extended period of time, our revenue 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.

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Construction of rigs could result in excess supply in international regions, which could reduce our ability to secure new contracts for our stacked rigs and could reduce our ability to renew, extend or obtain new contracts for working rigs at the end of such 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 the movement of jackup rigs, other mobile offshore drilling units and liftboats into the U.S. Gulf of Mexico. Improved market conditions in any region worldwide could lead to increased construction and upgraded 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 20, 2013, 86 jackup rigs were under construction or on order globally by industry participants, national oil companies and financial investors for delivery through 2015. Many of the rigs currently under construction have not been contracted for future work, which may intensify price competition as scheduled delivery dates occur. A significant increase in the supply of jackup rigs, other mobile offshore drilling units or liftboats could adversely affect both our utilization and dayrates.

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 could have a material adverse effect on our operations. During such severe weather conditions, our liftboats typically leave their location and cease to earn a full dayrate. The liftboats cannot return to the location until the weather improves and the seas are within U.S. Coast Guard approved limits. 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. In addition, we could stack a number of rigs in certain locations offshore. This concentration of rigs in specific locations could expose us to increased liability from a catastrophic event and could cause an increase in our insurance costs.

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 21, 2013, our total contract drilling backlog for our Domestic Offshore, International Offshore, International Liftboats and Inland segments was approximately \$682.2 million, which excludes the three-year rig commitment with Cabinda Gulf Oil Company Limited for use of the Ben Avon, as this acquisition has not yet closed. 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, less any penalties or reductions in dayrate for late delivery or non-compliance with

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contractual obligations. Backlog excludes revenue for management agreements, 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. 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, 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 and for pollution and blowout events. Insurance costs may increase in the event of ongoing patterns of adverse changes in weather or climate.

Further, we may elect not to obtain or we may be unable 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, equipment breakdowns, terrorist acts, piracy, war, civil disturbances, blowouts, 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 weather related and other events, 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 has suffered extensive damage from several hurricanes since 2005. As a result, our insurance costs have increased significantly, our deductibles have 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. Further, due to the escalating costs for weather-related damage in the U.S. Gulf of Mexico, in the future we may elect to forgo purchasing such coverage. 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 customers to indemnify us for such damages and risks.

Any violation of the Foreign Corrupt Practices Act ("FCPA") or similar laws and regulations could result in significant expenses, divert management attention, and otherwise have a negative impact on us.

We are subject to the FCPA, which generally prohibits U.S. companies and their intermediaries from making improper payments to foreign officials for the purpose of obtaining or retaining business, and the anti-bribery laws of other jurisdictions. On April 4, 2011, we received a subpoena from the Securities and Exchange Commission ("SEC")

requesting that we produce documents relating to our compliance with the FCPA. We were also advised by the Department of Justice ("DOJ") on April 5, 2011, that it was conducting a similar investigation. Under the direction of the audit committee, we conducted an internal investigation regarding these matters. On April 24, 2012 and August 7, 2012, we received letters notifying us that the DOJ and SEC, respectively, had completed their investigations and did not intend to pursue enforcement action against us. Despite the favorable termination of these investigations, we remain subject to the FCPA and similar laws and regulations, and any determination that we have violated the FCPA or laws of any other jurisdiction could have a material adverse effect on our financial condition.

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Our international operations may subject us to political and regulatory risks and uncertainties.

In connection with our international contracts, the transportation of rigs, services and technology across international borders subjects us to extensive trade laws and regulations. Our import and export activities are governed by unique customs laws and regulations in each of the countries where we operate. In each jurisdiction, laws and regulations concerning importation, recordkeeping and reporting, import and export control and financial or economic sanctions are complex and constantly changing. Our business and financial condition may be materially affected by enactment, amendment, enforcement or changing interpretations of these laws and regulations. Rigs and other shipments can be delayed and denied import or export for a variety of reasons, some of which are outside our control and some of which may result in failure to comply with existing laws and regulations and contractual requirements. Shipping delays or denials could cause operational downtime or increased costs, duties, taxes and fees. Any failure to comply with applicable legal and regulatory obligations also could result in criminal and civil penalties and sanctions, such as fines, imprisonment, debarment from government contracts, seizure of goods and loss of import and export privileges. 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 Southeast Asia, Saudi Arabia 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;
- 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 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 and Southeast Asia, 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.

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, the ownership of assets by local citizens and companies, 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



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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 revenue is 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 our inability to collect revenue 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 revenue, and the loss of one or more of these customers could adversely affect our financial condition and results of operations.

In recent years there has been a significant consolidation in our customer base. Therefore, we derive a significant amount of our revenue from a few energy companies. Chevron Corporation and Saudi Aramco accounted for 17% and 6% of our revenue for the year ended December 31, 2012, respectively. 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 either of these or any other significant customer could adversely affect our financial condition and results of operations.

We have contractual commitments related to our investment in Discovery Offshore and may not realize the anticipated benefits from our investment.

We have committed substantial management time to our investment in Discovery Offshore S.A., a development-stage publicly traded Luxembourg limited liability company, and may not realize anticipated benefits of our investment. Discovery Offshore was formed in 2011 for the purpose of owning two new-build ultra high specification harsh environment jackup drilling rigs, which are expected to be delivered in the second and fourth quarters of 2013. The delivery of the rigs is dependent on Discovery Offshore's ability to raise additional capital for payment of the balance of the construction price. Pursuant to the Services Agreements with respect to each rig, after delivery we will provide marketing, management, crew and operational services in exchange for a fixed daily fee of \$6,000 per rig plus five percent of rig-based EBITDA generated per day per rig. If Discovery Offshore fails to obtain contracts for its rigs at favorable day rates, or experiences construction delays or cost increases, we may not realize anticipated fees under the Services Agreements. In addition to these risks, our investment in Discovery Offshore is subject to other risks associated with our business described herein, many of which are unpredictable and fluctuate based on events outside our control.

Our existing 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, all of the new rigs under construction are of higher specification than our existing fleet. While Hercules has signed agreements to manage the construction and operations of the two ultra high specification harsh environment jackup drilling rigs on order for Discovery Offshore, 28 of our 37 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, 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.

Acquisitions and integrating such acquisitions create certain risk and may affect our operating results.

We have completed acquisitions and will consider pursuing acquisitions (including the acquisition of individual rigs and liftboats) in order to continue to grow and increase profitability. However, acquisitions involve numerous risks and

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uncertainties, including intense competition for suitable acquisition targets, the potential unavailability of financial resources necessary to consummate acquisitions, difficulties in identifying suitable acquisition targets or in completing any transactions identified on sufficiently favorable terms.

In addition to the risks involved in identifying and completing acquisitions described above, even when acquisitions are completed, integration of acquired entities can involve significant difficulties, such as:

- failure to achieve cost savings or other financial or operating objectives with respect to an acquisition;
- uncertainties and delays relating to upgrades and refurbishments of newly-acquired rigs and liftboats;
- inability to perform under drilling contracts due to various operational factors, including unscheduled repairs, maintenance, operational delays, health, safety and environmental incidents, weather events and our new customers seeking to cancel or renegotiate our contracts for various reasons;
- strain on the operational and managerial controls of our business;
- managing geographically separated organization, systems and facilities;
- difficulties in the integration and retention of customers or personnel and the integration and effective deployment of operations or technologies;
- assumption of unknown material liabilities or regulatory non-compliance issues;
- possible adverse short-term effects on our cash flows or operating results; and
- diversion of management's attention from the ongoing operations of our business.

Failure to manage these acquisition risks could have a material adverse effect on our results of operations, financial condition and cash flows. There can be no assurance that we will be able to consummate any acquisitions or expansions, successfully integrate acquired entities or assets, or generate positive cash flow at any acquired company or expansion project.

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 specified financial covenant levels, our revolving credit facility 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 revolving credit facility, 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.



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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 arising out of the Macondo well incident and those related to climate change 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 Coast Guard, the NTSB, the CBP, the Department of Interior, the BOEM and the BSEE, as well as private industry organizations such as the ABS. New laws, regulations and requirements imposed after the Macondo well incident may delay our operations and cause us to incur additional expenses in order for our rigs and operations in the U.S. Gulf of Mexico to be compliant with these new laws, regulations and requirements. These new laws, regulations and requirements and other potential changes in laws and regulations applicable to the offshore drilling industry in the U.S. Gulf of Mexico may also continue to prevent our customers from obtaining new drilling permits and approvals in a timely manner, if at all, which could materially adversely impact our business, financial position or results of operations. In addition, 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 FCPA, 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 change 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 to the laws, regulations and requirements implemented since the Macondo incident, the federal government has considered additional new laws, regulations and requirements, including those that would have imposed additional equipment requirements and that relate to the protection of the environment, which would be applicable to the offshore drilling industry in the U.S. Gulf of Mexico. The federal government may again consider implementing new laws, regulations and requirements. The implementation of new, more restrictive laws and regulations could lead to substantially increased potential liability and operating costs for us and our customers, which could cause our customers to discontinue or delay operating in the U.S. Gulf of Mexico and/or redeploy capital to international locations. These actions, if taken by any of our customers, could result in underutilization of our U.S. Gulf of Mexico assets and have an adverse impact on our revenue, profitability and financial position.

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 and regulations can be costly and could limit our operations.

Our operations are subject to federal, state, local and foreign and/or international laws and 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. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions restricting some or all of our activities in the affected areas. 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.

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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 revenue. Operating revenue 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 used for our rigs, 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, including shipyard incidents that could increase the cost and delay the timing of projects;
- 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, reactivation and refurbishment projects could exceed our planned capital expenditures. Failure to complete an upgrade, reactivation, 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, reactivation, 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 increase 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,

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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 hurricanes during the last several years and by the Macondo well blowout incident. 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.

Our operations present hazards and risks that require significant and continuous oversight, and we depend upon the security and reliability of our technologies, systems and networks in numerous locations where we conduct business. We continue to increase our dependence on digital technologies to conduct our operations, to collect monies from customers and to pay vendors and employees. In addition, we have outsourced certain information technology development, maintenance and support functions. As a result, we are exposed to cybersecurity risks at both our internal locations and outside vendor locations that could disrupt our operations for an extended period of time and result in the loss of critical data and in higher costs to correct and remedy the effects of such incidents, although no such material incidents have occurred to date. If our systems for protecting against information technology and cybersecurity risks prove to be insufficient, we could be adversely affected by having our business and financial systems compromised, our proprietary information altered, lost or stolen, or our business operations and safety procedures disrupted.

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, the ultimate repatriation of earnings from foreign subsidiaries to the United States, 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 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.

The availability under the \$75 million revolving credit facility is to be used for working capital, capital expenditures

and other general corporate purposes. All borrowings under the revolving credit facility mature on April 3, 2017. Except under certain conditions, the revolving credit facility requires interest-only payments on a quarterly basis until the maturity date. We intend to refinance the revolving credit facility before the revolving credit facility matures. No amounts were outstanding under the revolving credit facility as of December 31, 2012, although \$1.0 million in letters of credit had been issued under it. The remaining availability under the revolving credit facility is \$74.0 million at December 31, 2012.

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We currently maintain a shelf registration statement covering the future issuance from time to time of various types of securities, including debt and equity securities. 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 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, to fund capital expenditures 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. Applicable tax laws may also subject such payments to us by our subsidiaries to further taxation.

The inability of our subsidiaries to transfer cash 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 or Delaware law may inhibit a takeover, which could adversely affect the value of our common stock.

Our certificate of incorporation, bylaws 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.

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Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Our property consists primarily of jackup rigs, barge rigs, liftboats and ancillary equipment, substantially all of which we own. The majority of our vessels and substantially all of our other personal property, are pledged to collateralize our credit facility and 7.125% Senior Secured Notes.

We maintain offices, maintenance facilities, yard facilities, warehouses, waterfront docks as well as residential premises in various countries, including the United States, Nigeria, Singapore, Saudi Arabia, United Arab Emirates, Indonesia and Bahrain. Almost all of these properties are leased. Our leased principal executive offices are located in Houston, Texas.

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

Item 3. Legal Proceedings

The Company is involved in various claims and lawsuits in the normal course of business. As of December 31, 2012, management did not believe any accruals were necessary in accordance with FASB ASC 450-20, Contingencies - Loss Contingencies.

Termination of FCPA Investigations

On April 4, 2011, we received a subpoena issued by the SEC requesting the delivery of certain documents to the SEC in connection with its investigation into possible violations of the securities laws, including possible violations of the FCPA in certain international jurisdictions where we conduct operations. We were also notified by the DOJ on April 5, 2011, that certain of our activities were under review by the DOJ.

On April 24, 2012, we received a letter from the DOJ notifying us that the DOJ had closed its inquiry into us regarding possible violations of the FCPA and did not intend to pursue enforcement action against us or impose any fines or penalties against us. Additionally, on August 7, 2012, we received a letter from the SEC notifying us that the SEC staff had completed its investigation into us regarding possible violations of the FCPA and did not intend to pursue enforcement action against us or impose any fines or penalties against us. As a result of these terminations by the SEC and the DOJ, there are no open FCPA investigations against us.

Shareholder Derivative Suits

Say-on-Pay Litigation

In June 2011, two separate shareholder derivative actions were filed purportedly on our behalf in response to our failure to receive a majority advisory "say-on-pay" vote in favor of our 2010 executive compensation. On June 8, 2011, the first action was filed in the District Court of Harris County, Texas, and on June 23, 2011, the second action was filed in the United States Court for the District of Delaware. Subsequently, on July 21, 2011, the plaintiff in the Harris County action filed a concurrent action in the United States District Court for the Southern District of Texas. Each action named us as a nominal defendant and certain of our officers and directors, as well as our Compensation Committee's consultant, as defendants. Plaintiffs allege that our directors breached their fiduciary duty by approving excessive executive compensation for 2010, that the Compensation Committee consultant aided and abetted that breach of fiduciary duty, that the officer defendants were unjustly enriched by receiving the allegedly excessive compensation, and that the directors violated the federal securities laws by disseminating a materially false and misleading proxy. The plaintiffs seek damages in an unspecified amount on our behalf from the officer and director defendants, certain corporate governance actions, and an award of their costs and attorney's fees. We and the other defendants have filed motions to dismiss these cases for failure to make demand upon our board and for failing to state a claim. Those motions are pending. On June 11, 2012, the plaintiff in the Harris County action voluntarily dismissed his action.

We do not expect the ultimate outcome of any of these shareholder derivative 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 statements.

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We cannot predict with certainty the outcome or effect of any of the litigation matters specifically described above or of any 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 our current estimates.

Item 4. Mine Safety Disclosures

Not applicable.

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## 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 21, 2013, there were 130 stockholders of record. On February 21, 2013, the closing price of our common stock as reported by NASDAQ was \$6.58 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
2012		
Fourth Quarter	\$6.30	\$4.36
Third Quarter	5.03	3.22
Second Quarter	5.25	2.91
First Quarter	5.57	3.77
	Price High	Low
2011		
Fourth Quarter	\$4.58	\$2.25
Third Quarter	5.60	2.90
Second Quarter	6.99	4.97
First Quarter	6.72	3.04

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 as well as indentures governing the 7.125% Senior Secured Notes, 10.25% Senior Notes and 10.5% Senior Notes restrict our ability to pay dividends or other distributions on our equity securities.

## Issuer Purchases of Equity Securities

During the three months ended December 31, 2012, we did not repurchase any shares of our securities.

## Item 6. Selected Financial Data

We have derived the following condensed consolidated financial information as of December 31, 2012 and 2011 and for the years ended December 31, 2012, 2011 and 2010 from our audited consolidated financial statements included in Item 8 of this report. The condensed consolidated financial information as of December 31, 2010 and for the year ended December 31, 2009 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, 2011. The condensed consolidated financial information as of December 31, 2009 and for the year ended December 31, 2008 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, 2010, as amended by our current report on Form 8-K filed on July 8, 2011. The condensed consolidated financial information as of December 31, 2008 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, 2009.

We were formed in July 2004 and commenced operations in August 2004. From our formation to December 31, 2012, we completed our i) acquisition of 20 jackup rigs and related assets, accounts receivable, accounts payable and certain contractual rights from Seahawk Drilling, Inc. and certain of its subsidiaries ("Seahawk") ("Seahawk Transaction") on

April 27, 2011; ii) acquisition of TODCO and iii) acquisition of several significant asset acquisitions. Our financial results reflect the impact of the Seahawk Transaction and various asset acquisitions from their respective dates of closing which impacts the comparability of our historical financial results presented in the tables below.

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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, 2012(a)	Year Ended December 31, 2011	Year Ended December 31, 2010(b)	Year Ended December 31, 2009(c)	Year Ended December 31, 2008(d)
(In thousands, except per share data)					
Statement of Operations Data:					
Revenue	\$709,792	\$655,358	\$624,827	\$718,601	\$1,053,479
Operating loss	(63,577 )	(18,749 )	(143,427 )	(79,469 )	(1,040,848 )
Loss from continuing operations	(127,004 )	(66,520 )	(132,093 )	(81,047 )	(997,893 )
Loss per share from continuing operations:					
Basic and Diluted	\$(0.83 )	\$(0.51 )	\$(1.15 )	\$(0.83 )	\$(11.29 )
Balance Sheet Data (as of end of period):					
Cash and cash equivalents	\$259,193	\$134,351	\$136,666	\$140,828	\$106,455
Working capital	217,184	174,598	182,276	144,813	224,785
Total assets	2,016,630	2,006,704	1,995,309	2,277,476	2,590,895
Long-term debt, net of current portion	798,013	818,146	853,166	856,755	1,015,764
Total stockholders’ equity	882,762	908,553	853,132	978,512	925,315
Cash dividends per share	—	—	—	—	—

(a) Includes \$108.2 million (\$82.7 million, net of taxes or \$0.54 per diluted share) in asset impairment charges. In addition, 2012 includes an \$18.4 million gain (\$11.9 million, net of taxes or \$0.08 per diluted share) on the sale of Platform Rig 3 as well as a \$27.3 million gain (\$17.7 million, net of taxes or \$0.12 per diluted share) for the Hercules 185 insurance settlement.

(b) Includes \$122.7 million (\$79.8 million, net of taxes or \$0.69 per diluted share) in impairment of property and equipment charges.

(c) Includes \$26.9 million (\$13.1 million, net of taxes or \$0.13 per diluted share) of asset impairment charges. 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.

(d) Includes \$863.6 million (\$863.6 million, net of taxes or \$9.77 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, 2012(a)	Year Ended December 31, 2011	Year Ended December 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008(b)
(In thousands)					

## Other Financial Data:

## Net cash provided by (used in):

Operating activities	\$68,363	\$52,025	\$24,420	\$137,861	\$269,727
Investing activities	(52,269 )	(32,520 )	(21,306 )	(60,510 )	(515,787 )

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Financing activities	108,748	(21,820	) (7,276	) (42,978	) 140,063
Capital expenditures	167,180	39,483	22,018	76,141	585,084
Deferred drydocking expenditures	11,425	15,739	15,040	15,646	17,269

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(a) 2012 Capital expenditures includes the purchase of Hercules 266 as well as related equipment.

(b) 2008 Capital expenditures 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, 2012 and 2011 and for the years ended December 31, 2012, 2011 and 2010 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 21, 2013, we owned a fleet of 37 jackup rigs, thirteen barge rigs, 58 liftboat vessels and operated an additional five liftboat vessels owned by a third party. 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 several key shallow-water provinces around the world.

In March 2012, we acquired an offshore jackup drilling rig, Hercules 266, for \$40.0 million. We entered into a three-year drilling contract with Saudi Aramco for the use of this rig with Saudi Aramco having an option to extend the term for an additional one-year period. This rig is currently undergoing upgrades and other contract specific refurbishments and we expect the rig to commence work under the contract in the second quarter of 2013.

During April 2012, the Kingfish, a 230 class liftboat, began its mobilization from the U.S. Gulf of Mexico to the Middle East, where it underwent upgrades prior to becoming reactivated. The vessel commenced work in November 2012.

During November 2012, the decision was made to reactivate one of our previously cold stacked rigs, Hercules 209. Hercules 209 is currently in the shipyard undergoing repairs and upgrades for reactivation and is expected to be available for work in the second quarter of 2013.

As of February 21, 2013, our business segments include the following:

Domestic Offshore — includes 29 jackup rigs in the U.S. Gulf of Mexico that can drill in maximum water depths ranging from 85 to 350 feet. Nineteen of the jackup rigs are either under contract or available for contracts and ten are cold stacked.

International Offshore — includes eight jackup rigs outside of the U.S. Gulf of Mexico. We have three jackup rigs contracted offshore in Saudi Arabia, one jackup rig contracted offshore in Myanmar and one jackup rig contracted offshore in Cameroon. In addition, we have one jackup rig warm stacked and one jackup rig cold stacked in Bahrain as well as one jackup rig cold stacked in Malaysia. In addition to owning and operating our own rigs, we have the Construction Management Agreement and the Services Agreement with Discovery Offshore with respect to each of its two rigs.

Inland — includes a fleet of three conventional and ten 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 under contract or available and ten are cold stacked.

Domestic Liftboats — includes 39 liftboats in the U.S. Gulf of Mexico. Twenty-nine are operating or available for contracts and ten are cold stacked.

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

Our drilling 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 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. Under most of our liftboat contracts, we are paid a fixed dayrate for the rental of the vessel, which typically

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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, crane overtime and other items.

Our revenue is 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. Most of our international drilling contracts and some of our international liftboat contracts 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 revenue 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.

### Insurance Claims Settlement

In September 2011, we were conducting a required annual spud can inspection on Hercules 185 in protected waters offshore Angola. While conducting the inspection, it was determined that the spud can on the starboard leg had detached from the leg. Subsequently, additional leg damage was identified. The rig underwent repairs related to this damage and was mobilized back to Angola. During the return mobilization from the U.S. Gulf of Mexico to Angola, Hercules 185 experienced additional damage to its legs. We conducted a survey of the rig's legs above and below the water line and discovered extensive damage to various portions of the rig's legs. In June 2012, we determined that it was unfeasible to repair the damage and return the rig to service and recorded an impairment charge to write the rig down to salvage value. We and our insurance underwriters reached a global settlement in September 2012, agreeing that Hercules 185 should be considered a constructive total loss. From this settlement, we received total insurance proceeds of \$41.0 million for the rig, including \$7.5 million received in June 2012 for its earlier claim relating to previous leg damage to the rig. These proceeds generated a gain on insurance settlement of \$27.3 million which is included in Operating Expenses on the Consolidated Statements of Operations for the year ended December 31, 2012. As part of the settlement, we agreed to transport and attempt to sell the rig, which entitled us to the first \$1.5 million in proceeds from such sale and any sale proceeds in excess of \$1.5 million being split seventy-five percent to the underwriters and twenty-five percent to us.

### Dispositions and Impairment

In April 2012, during the return mobilization from the U.S. Gulf of Mexico to Angola, Hercules 185 experienced extensive damage to various portions of the rig's legs. We believed it was unfeasible to repair the damage and return

the rig to service and recorded an impairment charge of \$42.9 million (\$27.9 million, net of tax) which is included in Asset Impairment on the Consolidated Statements of Operations for the year ended December 31, 2012 to write the rig down to salvage value.

In August 2012, we sold the Platform Rig 3 and related legal entities for aggregate consideration of approximately \$36 million, consisting of a base purchase price of \$28 million, as adjusted for net working capital and recorded a gain of \$18.4 million which is included in Operating Expenses on the Consolidated Statements of Operations for the year ended December 31, 2012.

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In October 2012, we sold Hercules 252 for gross proceeds of \$8.0 million. The Consolidated Statements of Operations for the year ended December 31, 2012 include an impairment charge of approximately \$25.5 million (\$16.6 million, net of tax), related to the write-down of Hercules 252 to fair value less estimated cost to sell.

In September 2012, we made the decision to cold stack Hercules 258 effective October 1, 2012 and removed it from our marketable assets into our non-marketable assets as we do not reasonably expect to market this rig in the foreseeable future. This decision resulted in an impairment charge of approximately \$35.2 million (\$35.2 million, net of tax), which is included in Asset Impairment on the Consolidated Statements of Operations for the year ended December 31, 2012, to write the rig down to salvage value based on a third party estimate. The financial information for Hercules 258 has been reported as part of the International Offshore segment.

### Termination of Foreign Corrupt Practices Act Investigations

On April 4, 2011, we received a subpoena issued by the Securities and Exchange Commission (“SEC”) requesting the delivery of certain documents to the SEC in connection with its investigation into possible violations of the securities laws, including possible violations of the Foreign Corrupt Practices Act (“FCPA”) in certain international jurisdictions where we conduct operations. We were also notified by the Department of Justice (“DOJ”) on April 5, 2011, that certain of our activities were under review by the DOJ.

On April 24, 2012, we received a letter from the DOJ notifying us that the DOJ had closed its inquiry into us regarding possible violations of the FCPA and did not intend to pursue enforcement action against us or impose any fines or penalties against us. Additionally, on August 7, 2012, we received a letter from the SEC notifying us that the SEC staff had completed its investigation into us regarding possible violations of the FCPA and did not intend to pursue enforcement action against us or impose any fines or penalties against us. As a result of these terminations by the SEC and the DOJ, there are no open FCPA investigations against us.

### Common Stock Offering

In March 2012, we raised approximately \$96.7 million in net proceeds, after adjusting for underwriting discounts and offering expenses, from an underwritten public offering of 20.0 million shares of common stock, par value \$0.01 per share at a price to the public of \$5.10 per share (\$4.86, net of underwriting discounts). We used a portion of the net proceeds from the share offering to fund a portion of the purchase price for the acquisition of Hercules 266 and will use the remaining net proceeds for general corporate purposes as well as the costs associated with the upgrade and mobilization of Hercules 266.

## RECENT DEVELOPMENTS

Effective April 27, 2011 we completed the Seahawk Transaction. Our financial statements accounted for the Seahawk Transaction as a business combination and accordingly, the total consideration was allocated to Seahawk's net tangible assets based on their estimated fair values. Our financial statements have been prepared assuming the same characterization applies for income tax purposes, based on the facts in existence through December 31, 2012.

Seahawk is in a Chapter 11 proceeding in the U.S. Bankruptcy Court. In February 2013, at the direction of the Court, Seahawk made certain distributions to its equity holders. These distributions, taken together with other aspects of the acquisition, will change the tax treatment and will cause the Seahawk Transaction to be characterized as a reorganization pursuant to IRC §368(a)(1)(G). Therefore, for tax purposes we will record a carryover basis in the Seahawk assets and other tax attributes. Because of the ownership change certain of these carryovers may be subject to specific and in some cases an annual limitation on their utilization. In these instances, we will recognize valuation allowances as appropriate. These carryover attributes include net operating losses of \$187 million, tax credits of \$17 million, and tax basis in assets of \$70 million. Based on our current tax position, these will produce additional deferred tax assets of approximately \$35 million (gross additional deferred tax assets of \$56 million offset by valuation allowances of \$21 million). These tax attributes will be recorded in our financial statements in the first quarter of 2013 based on the effective date of the equity distribution. There can be no assurance that these deferred tax assets will be realized.

In February 2013, we entered into a definitive agreement to acquire the offshore drilling rig Ben Avon from a subsidiary of KCA Deutag. The purchase price was \$55.0 million in cash and we expect the acquisition to close in late March 2013. In addition, we signed a three-year rig commitment with Cabinda Gulf Oil Company Limited for use of

the Ben Avon. We expect the rig to commence work in the second quarter of 2013.

In February 2013, we entered into a definitive agreement to acquire the liftboat Titan 2, a 280 class vessel, from a subsidiary of KS Energy Ltd. The purchase price was \$42.0 million in cash and we expect the acquisition to close in early March 2013. The liftboat is currently located in Limbe, Cameroon. In addition, we signed a Letter of Intent for a short term commitment to use the Titan 2 and we expect the vessel to commence work shortly after the acquisition closes.

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RESULTS OF OPERATIONS

Generally, domestic drilling industry conditions improved in 2012, as the marketed supply of jackup rigs was further diminished and demand increased for our jackup rigs. Factors that led to the increase in demand included the relatively high price of crude oil and the shift by operators to liquids-rich drilling activities. Furthermore, during 2012 our Domestic Offshore segment benefited from the full-year addition of the rigs acquired in the Seahawk Transaction, which we completed on April 27, 2011. The results of the Seahawk Transaction are included in our results from the date of acquisition which impacts the comparability of the 2012 period with the corresponding 2011 and 2010 periods. Our International Offshore segment experienced weaker results due primarily to contract expiration on the international rig fleet during the prior year. While the majority of our international rigs were recontracted, market dayrates were significantly below prior contract dayrates.

Our Domestic Liftboat performance strengthened in 2012, primarily due to our efforts to negotiate higher dayrates across each vessel class. Our domestic liftboat operations are generally affected by the seasonal weather patterns in the U.S. Gulf of Mexico. These seasonal patterns may result in increased activity in the spring, summer and fall periods and a decrease in the winter months. High winds, significant rain, tropical storms, hurricanes and other inclement weather conditions prevalent in the U.S. Gulf of Mexico during the year affect our domestic liftboat operations, as these conditions typically require our liftboats to leave work locations and cease to earn a full dayrate. The liftboats cannot return to the location until the weather improves and the seas are less than U.S. Coast Guard approved limits. Demand for our domestic rigs may decline during hurricane season, which is generally considered June 1 through November 30, as our customers may reduce drilling activity. Accordingly, our operating results may vary from quarter to quarter, depending on factors outside of our control.

Our International Liftboat performance strengthened in 2012, primarily due to increases in dayrates, partially offset by higher repairs and maintenance and labor costs.

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

	Year Ended December 31,		Change	% Change	
	2012	2011			
	(Dollars in thousands)				
Domestic Offshore:					
Number of rigs (as of end of period)	29	38			
Revenue	\$355,762	\$217,450	\$138,312	63.6	%
Operating expenses	238,674	186,132	52,542	28.2	%
Asset impairment	25,502	—	25,502	n/m	
Depreciation and amortization expense	72,938	68,146	4,792	7.0	%
General and administrative expenses	8,130	9,275	(1,145)	(12.3)	)%
Operating income (loss)	\$10,518	\$(46,103)	) 56,621	n/m	
International Offshore:					
Number of rigs (as of end of period)	8	9			
Revenue	\$135,047	\$237,047	\$(102,000)	(43.0)	)%
Operating expenses	66,144	134,439	(68,295)	(50.8)	)%
Asset impairment	82,714	—	82,714	n/m	
Depreciation and amortization expense	45,577	52,278	(6,701)	(12.8)	)%
General and administrative expenses	(183)	) (7,512)	) 7,329	(97.6)	)%
Operating income (loss)	\$(59,205)	) \$57,842	(117,047)	n/m	
Inland:					
Number of barges (as of end of period)	14	17			
Revenue	\$28,015	\$28,180	\$(165)	(0.6)	)%
Operating expenses	26,175	22,973	3,202	13.9	%
Depreciation and amortization expense	12,842	14,589	(1,747)	(12.0)	)%
General and administrative expenses	652	1,388	(736)	(53.0)	)%
Operating loss	\$(11,654)	) \$(10,770)	) (884)	8.2	%
Domestic Liftboats:					
Number of liftboats (as of end of period)	39	40			
Revenue	\$63,832	\$56,575	7,257	12.8	%
Operating expenses	40,050	42,381	(2,331)	(5.5)	)%
Depreciation and amortization expense	15,524	15,329	195	1.3	%
General and administrative expenses	2,680	2,190	490	22.4	%
Operating income (loss)	\$5,578	\$(3,325)	) 8,903	n/m	

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	Year Ended December 31,		Change	% Change	
	2012	2011			
	(Dollars in thousands)				
International Liftboats:					
Number of liftboats (as of end of period)	24	24			
Revenue	\$127,136	\$116,106	\$11,030	9.5	%
Operating expenses	67,041	58,407	8,634	14.8	%
Depreciation and amortization expense	16,896	19,624	(2,728)	(13.9)	)%
General and administrative expenses	4,588	7,166	(2,578)	(36.0)	)%
Operating income	\$38,611	\$30,909	7,702	24.9	%
Total Company:					
Revenue	\$709,792	\$655,358	\$54,434	8.3	%
Operating expenses	438,084	444,332	(6,248)	(1.4)	)%
Asset impairment	108,216	—	108,216	n/m	
Depreciation and amortization expense	166,426	172,571	(6,145)	(3.6)	)%
General and administrative expenses	60,643	57,204	3,439	6.0	%
Operating loss	(63,577)	(18,749)	(44,828)	239.1	%
Interest expense	(79,172)	(79,178)	6	—	%
Loss on extinguishment of debt	(9,156)	—	(9,156)	n/m	
Other, net	1,896	(3,934)	5,830	n/m	
Loss before income taxes	(150,009)	(101,861)	(48,148)	47.3	%
Income tax benefit	23,005	35,341	(12,336)	(34.9)	)%
Loss from continuing operations	(127,004)	(66,520)	(60,484)	90.9	%
Loss from discontinued operations, net of taxes	—	(9,608)	9,608	n/m	
Net loss	\$(127,004)	\$(76,128)	\$(50,876)	66.8	%

"n/m" means not meaningful.

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

## Year Ended December 31, 2012

	Operating Days	Available Days	Utilization(1)	Average Revenue per Day(2)	Average Operating Expense per Day(3)
Domestic Offshore	5,760	6,588	87.4	% \$61,764	\$36,229
International Offshore	1,331	2,336	57.0	% 101,463	28,315
Inland	880	1,098	80.1	% 31,835	23,839
Domestic Liftboats	7,315	11,941	61.3	% 8,726	3,354
International Liftboats	5,367	7,562	71.0	% 23,688	8,866

## Year Ended December 31, 2011

	Operating Days	Available Days	Utilization(1)	Average Revenue per Day(2)	Average Operating Expense per Day(3)
Domestic Offshore	4,494	5,755	78.1	% \$48,387	\$32,343
International Offshore	2,131	2,828	75.4	% 111,237	47,539
Inland	966	1,095	88.2	% 29,172	20,980
Domestic Liftboats	7,290	12,983	56.2	% 7,761	3,264

International Liftboats	5,310	8,395	63.3	% 21,866	6,957
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- 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.
- (1) 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.
  - (2) 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.

2012 Compared to 2011

Revenue

Consolidated. The increase in consolidated revenue is described below.

Domestic Offshore. The rigs acquired from Seahawk contributed to \$72 million of the increase in revenue from our Domestic Offshore segment. The remaining increase was due to increased operating days and average dayrates for the legacy Hercules rigs during the Current Period as compared to the Comparable Period, which contributed to an increase in revenue of approximately \$34 million and \$32 million, respectively.

International Offshore. Revenue for our International Offshore segment decreased due to the following:

\$34.4 million decrease from Hercules 258 as it did not operate during most of the Current Period;

\$21.8 million decrease from Hercules 262 as it was in the shipyard preparing for a new contract a portion of the year which contributed to an approximate \$11 million decrease and it operated at a lower average dayrate which contributed to an approximate \$13 million decrease, net of other miscellaneous items;

\$21.6 million decrease from Hercules 261 as it was in the shipyard preparing for a new contract a portion of the year which contributed to an approximate \$10 million decrease and it operated at a lower average dayrate which contributed to an approximate \$13 million decrease, net of other miscellaneous items;

\$16.1 million decrease from Hercules 208 as it was preparing for a new contract in Indonesia during the first quarter which contributed to an approximate \$8 million decrease and it operated at a lower average dayrate which contributed to an approximate \$11 million decrease, offset partially by additional days worked in the fourth quarter which contributed to an approximate \$3 million increase;

\$5.2 million decrease from Platform Rig 3 as it was sold in August 2012; and

\$5.1 million decrease from Hercules 260 of which an approximate \$11 million decrease related to it operating at a lower dayrate in the Current Period than in the Comparable Period and not providing marine package services as were provided under the contract in the Comparable Period and an approximate \$5 million increase related to an increase in operating days in the Current Period as compared to the Comparable Period.

Inland. The slight decrease in revenue from our Inland segment resulted from a decline in operating days in the Current Period as compared to the Comparable Period which contributed to an approximate \$3 million decrease in revenue. Offsetting this decrease, average dayrates increased in the Current Period as compared to the Comparable Period which contributed to an approximate \$3 million increase to revenue.

Domestic Liftboats. The increase in revenue from our Domestic Liftboats segment resulted from an increase in average revenue per liftboat per day in the Current Period as compared to the Comparable Period.

International Liftboats. The increase in revenue from our International Liftboats segment resulted from an increase in average revenue per liftboat per day in the Current Period as compared to the Comparable Period contributing to an

approximate \$10 million increase in revenue. The remaining approximate \$1 million increase in revenue was due to an increase in operating days in the Current Period as compared to the Comparable Period.

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### Operating Expenses

Consolidated. The decrease in consolidated operating expenses is described below.

Domestic Offshore. The rigs acquired from Seahawk contributed to \$39 million increase in operating expenses for our Domestic Offshore segment. The remaining increase in operating expenses was due to an increase in labor costs of \$15.2 million in the Current Period as compared to the Comparable Period as well as gains on asset sales in the Comparable Period. These increases were partially offset by a \$7.8 million decrease in costs associated with workers' compensation.

International Offshore. Platform Rig 3 contributed a \$29.1 million decrease to operating expenses in the Current Period as compared to the Comparable Period. This decrease was primarily due to the gain on sale of the rig during the Current Period of \$18.4 million as well as approximately \$8 million of costs incurred in the Comparable Period for the permanent importation of the rig. Hercules 185 contributed a \$29.6 million decrease in operating expenses primarily due to a gain on insurance settlement of \$27.3 million in the Current Period. Hercules 258 contributed a \$12.8 million decrease in operating expenses primarily due to the rig not operating during most of the Current Period.

Inland. The increase in operating expenses for our Inland segment is due to current period incremental accrued sales and use tax expense of \$2.3 million related to several multi-year sales and use tax audits as well as an increase in workers' compensation expense of \$2.1 million in the Current Period. These increases were partially offset by \$0.9 million lower equipment rental expense in the Current Period as compared to the Comparable Period.

Domestic Liftboats. The decrease in operating expenses for our Domestic Liftboats segment related primarily to the \$1.8 million gain recognized on the loss of the Starfish recovered from insurance underwriters in excess of the net book value in the Current Period.

International Liftboats. The increase in operating expenses for our International Liftboats segment related primarily to \$2.5 million of incremental costs associated with the mobilization of the Kingfish to the Middle East, \$1.1 million of incremental costs associated with the Whaleshark repairs as well as an increase in labor and burden, equipment rentals, catering and workers' compensation costs of \$2.1 million, \$1.0 million, \$1.0 million and \$1.0 million, respectively, in the Current Period as compared to the Comparable Period. Partially offsetting these increases is a \$1.6 million gain recognized on the loss of the Mako recovered from insurance underwriters in excess of the net book value in the Current Period.

### Asset Impairment

We recorded an asset impairment charge of \$82.7 million in our International Offshore segment which includes \$35.2 million related to the write-down of Hercules 258 to salvage value, \$42.9 million related to the write-down of Hercules 185 to salvage value and \$4.6 million related to the write off of unamortized deferred costs associated with the Hercules 185 contract. Additionally, Hercules 252, which was held for sale at September 30, 2012, was written down to its fair value less estimated cost to sell, resulting in an impairment charge of \$25.5 million in the Current Period to our Domestic Offshore segment.

### Depreciation and Amortization

The decrease in depreciation and amortization is primarily due to the asset impairment charge recorded in the second quarter of 2012 to write-down Hercules 185 to salvage value, which contributed to a \$3.9 million decrease in depreciation. Depreciation decreased in the Current Period as compared to the Comparable Period by approximately \$1.9 million due to various assets sold. Additionally, amortization of drydock expenditures decreased \$2.8 million in the Current Period as compared to the Comparable Period. These decreases were partially offset by the additional depreciation in the Current Period as compared to the Comparable Period from the addition of the rigs acquired from Seahawk in April 2011.

### General and Administrative Expenses

The increase in general and administrative expenses is primarily related to higher recoveries of doubtful accounts receivable in the Comparable Period as compared to the Current Period. Additionally, labor costs increased \$4.7 million in the Current Period as compared to the Comparable Period. Partially offsetting this increase, we had a decrease in legal and professional service fees of \$7.4 million in the Current Period as compared to the Comparable Period.

### Loss on Extinguishment of Debt

During the second quarter of 2012, we expensed \$6.4 million related to the April 2012 debt refinancing and wrote off \$1.4 million of unamortized debt issuance costs associated with the April 2012 termination of our prior term loan. Additionally, in May 2012, we repurchased a portion of our 3.375% Convertible Senior Notes, resulting in a loss of \$1.3 million.

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## Other Income (Expense), net

The increase in other income is primarily due to the gain recognized in the Current Period for the change in the fair value of our warrants issued from Discovery Offshore as compared to a loss on the warrants in the Comparable Period.

## Income Tax Benefit

During the Current Period we generated an income tax benefit of \$23.0 million, for an effective rate of 15.3%, compared to an income tax benefit of \$35.3 million, for an effective rate of 34.7%, during the Comparable Period. The decline in our effective rate related primarily to the profitability of certain entities in our offshore structure, as we do not provide a U.S. tax provision/benefit for income/losses that are generated in this structure generally until funds are repatriated to the U.S. via capital transactions. During the Current Period we generated \$44.7 million of losses in our offshore structure, primarily related to the impairment of Hercules 258, which had no associated tax benefit recorded in the Current Period.

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

	Year Ended December 31,		Change	% Change	
	2011	2010			
	(Dollars in thousands)				
Domestic Offshore:					
Number of rigs (as of end of period)	38	25			
Revenue	\$217,450	\$124,063	\$93,387	75.3	%
Operating expenses	186,132	147,715	38,417	26.0	%
Asset impairment	—	84,744	(84,744)	n/m	
Depreciation and amortization expense	68,146	68,335	(189)	(0.3)	%)
General and administrative expenses	9,275	5,663	3,612	63.8	%
Operating loss	\$(46,103)	\$(182,394)	) 136,291	(74.7	%)
International Offshore:					
Number of rigs (as of end of period)	9	9			
Revenue	\$237,047	\$291,516	\$(54,469)	(18.7	%)
Operating expenses	134,439	130,460	3,979	3.0	%
Asset impairment	—	37,973	(37,973)	n/m	
Depreciation and amortization expense	52,278	58,275	(5,997)	(10.3	%)
General and administrative expenses	(7,512)	) 7,930	(15,442)	n/m	
Operating income	\$57,842	\$56,878	964	1.7	%
Inland:					
Number of barges (as of end of period)	17	17			
Revenue	\$28,180	\$21,922	\$6,258	28.5	%
Operating expenses	22,973	27,702	(4,729)	(17.1	%)
Depreciation and amortization expense	14,589	23,516	(8,927)	(38.0	%)
General and administrative expenses	1,388	(1,420)	) 2,808	n/m	
Operating loss	\$(10,770)	\$(27,876)	) 17,106	(61.4	%)
Domestic Liftboats:					
Number of liftboats (as of end of period)	40	41			
Revenue	\$56,575	\$70,710	\$(14,135)	(20.0	%)
Operating expenses	42,381	42,073	308	0.7	%
Depreciation and amortization expense	15,329	14,698	631	4.3	%
General and administrative expenses	2,190	1,850	340	18.4	%
Operating income (loss)	\$(3,325)	) \$12,089	(15,414)	n/m	



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	Year Ended December 31,		Change	% Change	
	2011	2010			
	(Dollars in thousands)				
International Liftboats:					
Number of liftboats (as of end of period)	24	24			
Revenue	\$116,106	\$116,616	\$(510)	(0.4)	)%
Operating expenses	58,407	55,879	2,528	4.5	%
Depreciation and amortization expense	19,624	17,711	1,913	10.8	%
General and administrative expenses	7,166	5,815	1,351	23.2	%
Operating income	\$30,909	\$37,211	(6,302)	(16.9)	)%
Total Company:					
Revenue	\$655,358	\$624,827	\$30,531	4.9	%
Operating expenses	444,332	403,829	40,503	10.0	%
Asset impairment	—	122,717	(122,717)	n/m	)
Depreciation and amortization expense	172,571	185,712	(13,141)	(7.1)	)%
General and administrative expenses	57,204	55,996	1,208	2.2	%
Operating loss	(18,749)	(143,427)	124,678	(86.9)	)%
Interest expense	(79,178)	(80,482)	1,304	(1.6)	)%
Other, net	(3,934)	3,876	(7,810)	n/m	)
Loss before income taxes	(101,861)	(220,033)	118,172	(53.7)	)%
Income tax benefit	35,341	87,940	(52,599)	(59.8)	)%
Loss from continuing operations	(66,520)	(132,093)	65,573	(49.6)	)%
Loss from discontinued operations, net of taxes	(9,608)	(2,501)	(7,107)	284.2	)%
Net loss	\$(76,128)	\$(134,594)	\$58,466	(43.4)	)%

"n/m" means not meaningful.

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

	Year Ended December 31, 2011				
	Operating Days	Available Days	Utilization	Average Revenue per Day	Average Operating Expense per Day
Domestic Offshore	4,494	5,755	78.1	% \$48,387	\$32,343
International Offshore	2,131	2,828	75.4	% 111,237	47,539
Inland	966	1,095	88.2	% 29,172	20,980
Domestic Liftboats	7,290	12,983	56.2	% 7,761	3,264
International Liftboats	5,310	8,395	63.3	% 21,866	6,957

  

	Year Ended December 31, 2010				
	Operating Days	Available Days	Utilization	Average Revenue per Day	Average Operating Expense per Day
Domestic Offshore	3,321	4,086	81.3	% \$37,357	\$36,151
International Offshore	2,106	3,344	63.0	% 138,422	39,013
Inland	986	1,095	90.0	% 22,233	25,299
Domestic Liftboats	9,641	13,870	69.5	% 7,334	3,033

International Liftboats	5,100	8,546	59.7	% 22,866	6,539
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2011 Compared to 2010

Revenue

Consolidated. This increase in consolidated revenue is described below.

Domestic Offshore. The increase in revenue was primarily due to revenue of \$74.4 million related to the rigs acquired from Seahawk. Excluding the revenue from the rigs acquired from Seahawk, revenue increased \$19.0 million for the legacy Hercules rigs due to an increase in average dayrates, \$47,000 in 2011 compared to \$37,357 in 2010, which contributed to an approximate \$32 million increase in revenue. This increase was partially offset by a decline in operating days for the legacy Hercules rigs to 3,043 days during 2011 from 3,321 days during 2010, which contributed to an approximate \$13 million decrease in revenue in 2011 as compared to 2010.

International Offshore. Hercules 258 and Hercules 260 contributed to a reduction in revenue of \$26.5 million and \$29.0 million, respectively, as their contracts ended in June and May 2011, respectively, and subsequently operated at lower dayrates. Additionally, there was no provision for marine services associated with the subsequent contracts. Hercules 262 and Hercules 208 contributed to a reduction of \$6.9 million and \$5.2 million, respectively, primarily due to fewer operating days in 2011 as compared to 2010. These decreases are partially offset by Hercules 185 operating a large portion of 2011 compared to not meeting revenue recognition criteria in 2010 which contributed to a \$15.2 million increase in revenue. Average revenue per rig per day decreased to \$111,237 in 2011 from \$138,422 in 2010 primarily due to lower average dayrates earned on Hercules 258 and Hercules 260.

Inland. The increase in revenue was driven primarily from a 31% increase in average dayrates in 2011 as compared to 2010.

Domestic Liftboats. The decrease in revenue resulted primarily from a 24% decline in operating days which contributed to an approximate \$18 million decrease in revenue, largely due to activity associated with the Macondo well blowout incident remediation efforts in 2010. This decrease was partially offset by an increase in average revenue per liftboat per day to \$7,761 in 2011 compared with \$7,334 in 2010, which contributed to an approximate \$4 million increase in revenue.

Operating Expenses

Consolidated. The increase in consolidated operating expenses is described below.

Domestic Offshore. The increase in operating expenses was primarily due to operating expenses of approximately \$41 million related to the rigs acquired from Seahawk. Excluding the operating expenses related to the rigs acquired from Seahawk, operating expenses decreased approximately \$3 million driven by a decrease in labor expense, equipment rentals, insurance, repairs and maintenance and freight costs of \$6.6 million, \$5.2 million, \$3.8 million, \$0.9 million and \$1.3 million, respectively, offset by an increase in workers' compensation expenses of \$12.1 million as well as \$7.0 million fewer gains on asset sales in 2011 as compared to 2010. Additionally, 2010 included an accrual of approximately \$3.0 million related to a multi-year state sales and use tax audit. Average operating expenses per rig per day were \$32,343 in 2011 compared with \$36,151 in 2010.

International Offshore. The increase in operating expenses was driven by i) increased operating expenses for Hercules 185 which contributed to a \$12.0 million increase in 2011 as compared to 2010, ii) increased operating expenses for Rig 3 which contributed to a \$4.5 million increase in 2011 as compared to 2010 primarily due to permanent importation costs of approximately \$8 million, offset by a \$1.7 million benefit for a forfeited deposit and a \$1.0 million deferral of contract preparation costs as well as iii) increased operating expenses for Hercules 208 which contributed to a \$6.0 million increase in 2011 as compared to 2010 primarily due to \$2.3 million in amortization of deferred costs as well as approximately \$2.8 million in costs incurred for the planned demobilization of the rig from Vietnam, which was delayed as a result of inclement weather. Partially offsetting these increases i) Hercules 156 was cold stacked in December 2010 which contributed to a \$6.5 million decrease, ii) Hercules 260 contributed to a \$5.0 million decrease primarily due to not providing marine services under its new contract which contributed to an approximate \$7 million decrease offset by increased amortization of deferred expenses of \$2.9 million in 2011 as compared to 2010 and iii) Hercules 258 contributed to a \$8.4 million decrease primarily due to not providing marine services subsequent to its contract expiration in June 2011. Average operating expenses per rig per day were \$47,539 in 2011 compared with \$39,013 in 2010.

Inland. The decrease in operating expenses is primarily due to an accrual in 2010 of approximately \$3.0 million related to a multi-year state sales and use tax audit. In addition, labor costs decreased \$1.3 million in 2011 as compared to 2010. Average operating expenses per rig per day were \$20,980 in 2011 compared with \$25,299 in 2010.

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International Liftboats. The increase in operating expenses is primarily due to increased labor costs in 2011.

### Impairment of Property and Equipment

In the year ended December 31, 2010, we incurred \$122.7 million of impairment charges related to certain property and equipment in our Domestic Offshore and International Offshore segments, the impact of which by segment was \$84.7 million and \$38.0 million, respectively.

### Depreciation and Amortization

The decrease in depreciation and amortization resulted primarily from reduced depreciation in 2011 of approximately \$26.0 million due to asset sales and fully depreciated assets as well as asset impairments recorded in the fourth quarter of 2010, partially offset by an approximate \$11 million increase in depreciation in 2011 due to capital additions, including \$7.0 million of depreciation related to the addition of the rigs acquired from Seahawk. Additionally, drydock amortization increased \$2.2 million.

### General and Administrative Expenses

The increase in general and administrative expenses is related to an increase in labor costs, including contract labor, of \$4.1 million as well as an increase of \$10.2 million in legal and professional service fees, of which \$3.4 million related to the Seahawk Transaction. These increases were partially offset by a \$13.9 million reduction in bad debt expense in 2011 as compared to 2010 due primarily to additional recoveries from one international customer.

### Interest Expense

The decrease in interest expense was related primarily to the impact of our interest rate collar outstanding in 2010, somewhat offset by the increased rate on our term loan

### Other Expense

The increase in other expense was primarily due to the 2011 recording of the fair market value of our Discovery Offshore Warrants of \$3.3 million as well as a \$3.3 million currency gain in 2010 due to the devaluation of the Venezuelan Bolivar. Additionally, during 2011, we amended our prior credit agreement and in doing so, we recorded the write-off of certain deferred debt issuance costs and expensed certain fees directly related to these activities totaling \$0.5 million.

### Income Tax Benefit

The effective tax rate in 2011 of 34.7% decreased as compared to the effective tax rate in 2010 of 40.0% due to mix of earnings (losses) from different jurisdictions as well as the prior year benefit of \$5.8 million related to the effective compromise settlement with the Mexican tax authorities on certain tax liabilities, partially offset by adjustments for various discrete items, including certain return to provision adjustments in 2010. In some cases our income tax is based on gross revenues or deemed profits under local tax laws rather than income before taxes. In addition, our assets move between taxing jurisdictions and operating structures with differing tax rates. As a result, variations in our effective tax rate from period to period may have limited correlation with pre-tax income or loss.

### Discontinued Operations

The increased loss was primarily the result of the \$13.4 million loss recognized for the Delta Towing Sale in May 2011.

### 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) under certain scenarios the Credit Agreement requires us to maintain compliance with a maximum secured leverage ratio, which contains 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

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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. Because all companies do not use identical calculations, the amounts below may not be comparable to other similarly titled measures of other companies.

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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,		
	2012	2011	2010
Operating Loss	\$ (63,577	) \$ (18,749	) \$ (143,427
Adjustments:			
Asset impairment	108,216	—	122,717
Gain on sale of Platform Rig 3	(18,350	) —	—
Gain on Hercules 185 insurance settlement	(27,268	) —	—
Total adjustments	62,598	—	122,717
Adjusted Operating Loss	\$ (979	) \$ (18,749	) \$ (20,710
Loss from Continuing Operations	\$ (127,004	) \$ (66,520	) \$ (132,093
Adjustments:			
Asset impairment	108,216	—	122,717
Gain on sale of Platform Rig 3	(18,350	) —	—
Gain on Hercules 185 insurance settlement	(27,268	) —	—
Loss on extinguishment of debt	9,156	—	—
Tax impact of adjustments	(12,796	) —	(42,959
Total adjustments	58,958	—	79,758
Adjusted Loss from Continuing Operations	\$ (68,046	) \$ (66,520	) \$ (52,335
Diluted Loss per Share from Continuing Operations	\$ (0.83	) \$ (0.51	) \$ (1.15
Adjustments:			
Asset impairment	0.70	—	1.07
Gain on sale of Platform Rig 3	(0.12	) —	—
Gain on Hercules 185 insurance settlement	(0.18	) —	—
Loss on extinguishment of debt	0.06	—	—
Tax impact of adjustments	(0.07	) —	(0.38
Total adjustments	0.39	—	0.69
Adjusted Diluted Loss per Share from Continuing Operations	\$ (0.44	) \$ (0.51	) \$ (0.46
Loss from Continuing Operations	\$ (127,004	) \$ (66,520	) \$ (132,093
Interest expense	79,172	79,178	80,482
Income tax benefit	(23,005	) (35,341	) (87,940
Depreciation and amortization	166,426	172,571	185,712
EBITDA	95,589	149,888	46,161
Adjustments:			
Asset impairment	108,216	—	122,717
Gain on sale of Platform Rig 3	(18,350	) —	—
Gain on Hercules 185 insurance settlement	(27,268	) —	—
Loss on extinguishment of debt	9,156	—	—
Total adjustments	71,754	—	122,717
Adjusted EBITDA	\$ 167,343	\$ 149,888	\$ 168,878

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### 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 natural gas prices. To the extent prices decline, this decline may 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 2 to our consolidated financial statements. We believe that our more critical accounting policies include those related to business combinations, property and equipment, derivatives, revenue recognition, income taxes, allowance for doubtful accounts, stock-based compensation and accrued self-insurance reserves. Inherent in such policies are certain key assumptions and estimates.

### Business Combinations

On April 27, 2011, we completed our acquisition of 20 jackup rigs and related assets, accounts receivable, accounts payable and certain contractual rights from Seahawk for total consideration of approximately \$150.3 million consisting of \$25.0 million of cash and 22.1 million shares of Hercules common stock, net of a working capital adjustment. We accounted for this transaction as a business combination and accordingly, the total consideration was allocated to Seahawk's net tangible assets based on their estimated fair values. Our Financial Statements have been prepared assuming the same characterization applies for income tax purposes, based on the facts in existence through December 31, 2012. Seahawk is in a Chapter 11 proceeding in the U.S. Bankruptcy Court. Subsequent to December 31, 2012, at the direction of the Court, Seahawk made certain distributions to its equity holders. These distributions, taken together with other aspects of the acquisition, will change the tax treatment and will cause the Seahawk Transaction to be characterized as a reorganization pursuant to IRC §368(a)(1)(G) (See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Recent Developments).

### Property and Equipment

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. 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 such assets 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 charges are recorded using an estimate of discounted future cash flows. This evaluation requires us to make judgments regarding long-term forecasts of future revenue 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

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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 and salvage values of individual rigs and vessels.

When analyzing our assets for impairment, we separate our marketable assets, those assets 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 assets, those assets that have been cold stacked for an extended period of time or those assets that we currently do not reasonably expect to market in the foreseeable future.

### Derivatives

As compensation for costs incurred and efforts expended in forming Discovery Offshore, we were issued warrants to purchase up to 5.0 million additional shares of Discovery Offshore stock at a strike price of 11.5 Norwegian Kroner (“NOK”) per share which is exercisable in the event that the Discovery Offshore stock price reaches an average equal to or higher than 23 NOK per share for 30 consecutive trading days. As of December 31, 2012 and 2011, Discovery Offshore’s stock price was 13.00 and 8.50 NOK per share, respectively. The warrants are being accounted for as a derivative instrument as the underlying security is readily convertible to cash. The fair value of the derivative asset of \$4.0 million and \$1.8 million is included in Other Assets, Net on the Consolidated Balance Sheet at December 31, 2012 and 2011, respectively. Subsequent changes in the fair value of the warrants are recognized to other income (expense). We recognized \$2.2 million to other income and \$3.3 million to other expense related to the change in the fair value of the warrants during the year ended December 31, 2012 and 2011, respectively. The fair value of the Discovery Offshore warrants was determined using a Monte Carlo simulation and is a Level 2 measurement within the fair value hierarchy. We used the historical volatility of companies similar to that of Discovery Offshore to estimate volatility. The risk-free interest rate assumption was based on observed interest rates consistent with the approximate life of the warrants. The stock price represents the closing stock price of Discovery Offshore stock at the date of valuation, which is the end of the respective reporting period. The strike price, target price, expected life and number of warrants are all contractual based on the terms of the warrant agreement. Our estimate of fair value requires a number of inputs and changes to those inputs could result in a different valuation.

### Revenue Recognition

Revenue generated from our contracts is recognized as services are performed, as long as collectability is reasonably assured. For certain contracts, we may receive lump-sum fees for the mobilization of equipment and personnel. Mobilization fees received and costs incurred to mobilize a rig from one location to another under contracts longer than ninety days are recognized as services are performed over the term of the related drilling contract. For certain contracts, we may receive fees from our customers for capital improvements to our rigs. Such fees are deferred and recognized as services are performed over the term of the related contract. We capitalize such capital improvements and depreciate them over the useful life of the asset. Certain of our contracts also allow us to recover additional direct costs, such as demobilization costs, additional labor and additional catering costs and 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.

### Accrued Self-Insurance Reserves

We are self-insured up to certain retention limits for maritime employer's liability claims and protection and indemnity claims. The amounts in excess of the self-insured levels are fully insured, up to a limit. Self-insurance reserves are based on estimates of (i) claims reported and (ii) loss amounts incurred but not reported. Reserves for reported claims are estimated by our internal risk department by evaluating the facts and circumstances of each claim and are adjusted

from time to time based upon the status of each claim and our historical experience with similar claims. Reserves for loss amounts incurred but not reported are estimated by our third-party actuary and include provisions for expected development on claims reported due to information not yet received and expected development on claims to be reported in the future but which have occurred prior to the accounting date. As of December 31, 2012 and 2011, there was \$27.9 million and \$22.1 million in Accrued Self-Insurance Reserves, respectively, which is included in Accrued Liabilities on the Consolidated Balance Sheets. The actual outcome of any claim could differ significantly from estimated amounts.

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## Income Taxes

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.

## Allowance for Doubtful Accounts

Accounts receivable represents approximately 8.3% of our total assets and 35.1% of our current assets as of December 31, 2012. Accounts receivable are stated at the historical carrying amount net of write-offs and the allowance for doubtful accounts. 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. We establish an allowance for doubtful accounts based on the actual amount we believe is not collectable. As of December 31, 2012 and 2011, there was \$0.8 million and \$11.5 million in allowance for doubtful accounts, respectively. The change in our allowance during the year ended December 31, 2012 related primarily to payments received from a customer in our International Offshore segment.

## Stock-Based Compensation

We recognize compensation cost for all share-based payments awarded in accordance with Financial Accounting Standards Board (“FASB”) Accounting Standards Codification (“ASC”) 718, Compensation — Stock Compensation (“ASC 718”) and in accordance with such we record the grant date fair value of stock options and time-based restricted stock awarded as compensation expense using a straight-line method over the requisite service period. Performance based awards are recognized using the accelerated method over the requisite service period. 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). The fair value of our time-based restricted stock and performance based grants that are share settled is based on the closing price of our common stock on the date of grant. For those performance based grants that contain a market performance condition, the Monte Carlo simulation is used for valuation as of the date of grant. All of our cash settled awards are recorded as a liability at fair value, which is remeasured at the end of each reporting period, over the requisite service period. Our cash settled liability awards that contain market performance conditions are valued using a Monte Carlo simulation, while the service based liability retention award is valued based on the lesser of the average price of the our common stock for the 90 days prior to the end of the quarter or date of vesting and \$10.00. We also estimate future forfeitures and related tax effects. 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.

Our estimate of future expense relating to stock options, restricted stock and liability-based awards granted through December 31, 2012 as well as the remaining vesting period over which the associated expense is to be recognized is presented in the table below; however, due to the uncertainty in the level of awards to be granted in the future as well as changes in the fair value of liability-based awards, these amounts are estimates and subject to change.

	December 31, 2012	
	Unrecognized Compensation Expense	Weighted Average Remaining Term
	(in thousands)	(in years)
Stock Option Awards	\$ 121	0.2
Time-based Restricted Stock Awards	4,632	1.2

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Objective-based Awards (share settled)	1,921	1.2
Objective-based Awards (cash settled)	1,563	0.9

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OUTLOOK

Offshore

Demand for our oilfield services is driven by our Exploration and Production customers' capital spending, which can experience significant fluctuations depending on current commodity prices and their expectations of future price levels, among other factors.

Drilling activity levels in the shallow-water U.S. Gulf of Mexico are dependent on crude oil and natural gas prices, prospectivity of hydrocarbons, as well as our customers' ability to obtain necessary drilling permits to operate in the region. Although natural gas has historically accounted for a greater percentage of hydrocarbon production in the U.S. Gulf of Mexico, our domestic offshore customers are increasingly focused on drilling activities that contain higher concentrations of crude oil and condensates. We expect this trend to continue, given the disparity between the price of crude oil and natural gas. As of February 20, 2013, the spot price for Louisiana Light Sweet ("LLS") crude was \$116.71 per barrel. LLS crude oil prices have fluctuated significantly over the past year, peaking at a high of \$130.49 per barrel to a low of \$89.69 per barrel. Throughout this period of volatility, we did not experience any material reduction in demand for our services, and we believe current oil prices remain supportive for a continuation of activity levels.

The supply of marketed jackup rigs in the U.S. Gulf of Mexico has declined significantly since the financial crisis starting in 2008 and again with the imposition of new regulations during 2010. Drilling contractors have elected to cold stack, or no longer actively market, a number of rigs in the region, and in other instances have mobilized rigs out of the U.S. Gulf of Mexico. As a result, the number of existing, actively marketed jackup rigs in the U.S. Gulf of Mexico, excluding rigs scheduled to move to international locations, has declined from approximately 63 rigs in late 2008 to 40 rigs as of February 20, 2013, of which we estimate that 34 rigs are contracted.

We are encouraged by the reduction in the marketed supply of jackup rigs in the U.S. Gulf of Mexico, and the relatively limited supply of uncontracted rigs. Discussions with our domestic customers suggest an extensive inventory of oil and liquids directed drilling opportunities exists in the U.S. Gulf of Mexico Shelf. Relatively high crude oil prices and our customers' emphasis on drilling oil and liquids rich prospects leads us to believe that healthy levels of rig demand and pricing in the region will persist. Tempering these positive conditions in the U.S. Gulf of Mexico is the market expectation for a prolonged period of low natural gas prices. We also expect to experience some inflationary pressures on operating costs in 2013, particularly in labor, as strong drilling activity in the U.S. has led to a tightening of skilled labor across the oilfield service industry, and insurance. In addition, any new regulatory or legislative changes that would affect shallow-water drilling activity in the U.S. Gulf of Mexico could have a material impact on Domestic Offshore's financial results.

Demand for rigs in our International Offshore segment is primarily dependent on crude oil prices. Relatively high crude oil prices, capital budget announcements by National and International Oil Companies, as well as what appears to be an increase in the number of international tenders for drilling rigs, leads us to believe that international capital spending and demand for drilling rigs overseas will increase in 2013. Our expectation for greater international rig demand is tempered by the current number of idle jackup rigs and the anticipated growth in supply from newly constructed rigs. As of February 20, 2013, there were 399 existing, actively marketed jackup rigs in international regions, excluding cold stacked rigs, of which only 23 rigs were uncontracted. There are also approximately 21 cold stacked jackup rigs in the international markets. In addition, globally, there are an estimated 86 new jackup rigs either under construction, on order, or planned for delivery through 2015, of which 60 are without contracts. All of the jackup rigs under construction have higher specifications than the rigs in our existing fleet. We expect that increased market demand will absorb a significant portion of the incremental supply of newbuild drilling rigs.

Our international drilling fleet consists of six jackup rigs, excluding Hercules 156 and Hercules 258, which are cold stacked, and Hercules 185, which is no longer in service and is expected to be sold for scrap. Three of our rigs are under long term (multi-year) contracts. One of these rigs, Hercules 266, is currently undergoing contract specific capital upgrade work before commencing on a three year contract. We anticipate contract commencement in the second quarter of 2013.

Inland barge drilling activity has slowed dramatically since 2008, as a number of key operators have curtailed or ceased activity in the inland market for various reasons, including lack of funding, lack of drilling success and

reallocation of capital to other onshore basins. The predominance of smaller independent operators active in inland waters adds to the volatility of this region. Inland activity levels stabilized in 2010 but remain depressed relative to historical levels. As of February 18, 2013, we estimate there were 25 marketed barge rigs, of which 18 were contracted. We expect industry activity levels to remain relatively weak through 2013, particularly in the first quarter, barring a significant increase in natural gas prices and/or property transfers to new operators that may spur drilling activity in this region.

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Liftboats

Demand for liftboats is typically a function of our customers' demand for offshore infrastructure inspection and maintenance, well maintenance, well plugging and abandonment, offshore construction and other related activities. Although activity levels for liftboats are not as closely correlated to commodity prices as our drilling segments, commodity prices are still a key driver of liftboat demand. In addition, liftboat demand in the U.S. Gulf of Mexico typically experiences seasonal fluctuations, due in large part to the operating limitations of liftboats in rough waters, which tend to occur during the winter months. We expect our utilization during the first quarter of 2013 to follow similar seasonal trends, with possible modest pricing improvement relative to year ago levels. On occasion, domestic liftboat demand will experience a sharp increase due to the occurrence of exogenous events such as hurricanes or maritime incidents that result in extraordinary damage to offshore infrastructure or require coastal restoration work. During the first quarter of 2013, in order to better align our expectations of future demand with supply, we have reduced the number of actively marketed liftboats in the U.S. Gulf of Mexico by three vessels. This class of vessels is the smallest in our fleet, has experienced average utilization of 50% or less over the past two years, and future demand for this class is not expected to materially increase. Future decisions to stack or reactivate vessels will depend on our assessment of long term market demand for each specific asset class.

Our International Liftboat segment is driven by our customers' demand for offshore production, infrastructure construction, maintenance and support activities in West Africa and the Middle East. While international rates for liftboats typically exceed those in the U.S., operating costs are also higher, and we expect this dynamic to continue through the foreseeable future. Utilization can and has been negatively impacted by local labor disputes and regional conflicts, particularly in West Africa. We expect the liftboat market in West Africa to potentially be impacted by additional vessels mobilizing into the region, which may place pressure on utilization and pricing for our liftboat fleet. In the Middle East, we expect healthy multi-year demand for liftboats to support increases in construction and well servicing activity levels. In late 2012, we added a third vessel to the Middle East in response to growing demand in the region.

Over the long term, we believe that international liftboat demand will benefit from: (i) the aging offshore infrastructure and maturing offshore basins, (ii) desire by our international customers to economically produce from these mature basins and service their infrastructure and (iii) the cost advantages of liftboats to perform these services relative to alternatives. Tempering this demand outlook is (i) our expectation of increased competition from newly constructed liftboats and mobilizations of existing liftboats primarily from the U.S. Gulf of Mexico to international markets, (ii) the risk of recurring political and social unrest, principally in West Africa and (iii) increased pressure to have local ownership of assets, principally in West Africa.

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## LIQUIDITY AND CAPITAL RESOURCES

## Sources and Uses of Cash

Sources and uses of cash for 2012 and 2011 are as follows (in millions):

	2012		2011	
Net Cash Provided by Operating Activities	\$68.4		\$52.0	
Net Cash Provided by (Used in) Investing Activities:				
Acquisition of Assets	(40.0)	)	(25.0)	)
Additions of Property and Equipment	(127.2)	)	(39.5)	)
Deferred Drydocking Expenditures	(11.4)	)	(15.7)	)
Cash Paid for Equity Investment	(4.3)	)	(34.2)	)
Insurance Proceeds Received	54.1		—	
Proceeds from Sale of Assets, Net	72.9		80.4	
Decrease in Restricted Cash	3.6		1.5	
Total	(52.3)	)	(32.5)	)
Net Cash Provided by (Used in) Financing Activities:				
Long-term Debt Borrowings	500.0		—	
Long-term Debt Repayments	(452.9)	)	(22.2)	)
Redemption of 3.375% Convertible Senior Notes	(27.6)	)	—	
Common Stock Issuance	96.7		—	
Payment of Debt Issuance Costs	(7.7)	)	(2.1)	)
Other	0.2		2.5	
Total	108.7		(21.8)	)
Net Increase (Decrease) in Cash and Cash Equivalents	\$124.8		\$(2.3)	)

## Insurance Proceeds

The Company intends to use the proceeds received from insurance settlements to reinvest in its existing fleet or for growth opportunities.

## 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, in certain instances we would be required to allocate the proceeds of such debt to repay or refinance existing debt. We currently believe we will have adequate liquidity 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 refinance existing debt or for general corporate purposes. In June 2013, we expect we will be required to settle our 3.375% Convertible Senior Notes. As of December 31, 2012, the notional amount of these notes outstanding was \$68.3 million. We intend to settle this obligation with cash on hand.

## Cash Requirements and Contractual Obligations

## Debt

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

At December 31, 2011, we previously had a \$592.9 million credit agreement, consisting of a \$452.9 million term loan facility and a \$140.0 million revolving credit facility. In addition to our scheduled payments, in January 2012, we used the net proceeds from asset sales to retire \$17.6 million of the outstanding balance of our term loan facility as required under the prior credit agreement. In addition, on April 3, 2012, we repaid in full all outstanding indebtedness under the prior secured credit facilities, and the liens securing such obligations were terminated. There were no termination penalties incurred by us in connection with the termination of the prior secured credit facility.

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On April 3, 2012, we entered into a new credit agreement (the “Credit Agreement”), which governs the new senior secured revolving credit facility (the “Credit Facility”), which provides for a \$75.0 million senior secured revolving credit facility, with a \$25.0 million sublimit for the issuance of letters of credit. As of December 31, 2012, no amounts were outstanding and \$1.0 million in letters of credit had been issued under the Credit Facility, therefore, the remaining availability under this facility was \$74.0 million.

We may prepay borrowings under the Credit Facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements. The Credit Agreement requires mandatory prepayments of amounts outstanding thereunder with the net proceeds of certain asset sales, casualty events, preferred stock issuances and debt issuances, but these mandatory prepayments do not require any reduction of the lenders' commitments under the Credit Agreement. All borrowings under the Credit Facility mature on April 3, 2017.

Borrowings under the Credit Facility bear interest, at our option, at either (i) the Alternate Base Rate (“ABR”) (the highest of the administrative agent's corporate base rate of interest, the federal funds rate plus 0.5%, or the one-month Eurodollar rate (as defined in the Credit Agreement) plus 1%), plus an applicable margin that ranges between 3.0% and 4.5%, depending on our leverage ratio, or (ii) the Eurodollar rate plus an applicable margin that ranges between 4.0% and 5.5%, depending on our leverage ratio. We will pay a per annum fee on all letters of credit issued under the Credit Facility, which fee will equal the applicable margin for loans accruing interest based on the Eurodollar rate, and we will pay a commitment fee of 0.75% per annum on the unused availability under the Credit Facility.

In addition, during any period of time that outstanding letters of credit under the Credit Facility exceed \$10 million or there are any revolving borrowings outstanding under the Credit Facility, we will have to maintain compliance with a maximum secured leverage ratio (as defined in the Credit Agreement, being generally computed as the ratio of secured indebtedness to consolidated cash flow). The maximum secured leverage ratio is 3.50 to 1.00.

Our obligations under the Credit Agreement are guaranteed by substantially all of our current domestic subsidiaries (collectively, the “Guarantors”), and the obligations of the Company and the Guarantors are secured by liens on substantially all of the vessels owned by the Company and the Guarantors, together with certain accounts receivable, equity of subsidiaries, equipment and other assets.

On April 3, 2012, we completed the issuance and sale of \$300.0 million aggregate principal amount of senior secured notes at a coupon rate of 7.125% (“7.125% Senior Secured Notes”) with maturity in April 2017. These notes were sold at par and we received net proceeds from the offering of the notes of \$293.0 million after deducting the initial purchasers' discounts and offering expenses. Interest on the notes is payable in cash semi-annually in arrears on April 1 and October 1 of each year.

The 7.125% Senior Secured Notes are guaranteed by each of the Guarantors that guarantee our obligations under our Credit Agreement. The notes are secured by liens on all collateral that secures our obligations under our Credit Agreement, subject to limited exceptions. The liens securing the notes share on an equal and ratable first priority basis with liens securing our Credit Agreement. Under the intercreditor agreement the collateral agent for the lenders under our Credit Agreement is generally entitled to sole control of all decisions and actions.

On April 3, 2012, we completed the issuance and sale of \$200.0 million aggregate principal amount of senior notes at a coupon rate of 10.25% (“10.25% Senior Notes”) with maturity in April 2019. These notes were sold at par and we received net proceeds from the offering of the notes of \$195.4 million after deducting the initial purchasers' discounts and offering expenses. Interest on the notes is payable in cash semi-annually in arrears on April 1 and October 1 of each year.

The 10.25% Senior Notes are guaranteed by each of the Guarantors that guarantee our obligations under our Credit Agreement.

In 2009, we issued \$300.0 million of senior notes at a coupon rate of 10.5% with maturity in October 2017 (“10.5% Senior Notes”). The interest on the 10.5% Senior Notes is payable in cash semi-annually in arrears on April 15 and October 15 of each year, to holders of record at the close of business on April 1 or October 1. 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. As of December 31, 2012, \$300.0 million notional amount of the 10.5% Senior Notes was outstanding.

The indenture governing the 10.5% Senior Notes provides that all the liens securing the notes may be released if our total amount of secured indebtedness, other than the 10.5% Senior 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.” When a collateral suspension is in effect, the 10.5% Senior Notes due 2017 become unsecured. Following the closing of the 2012 debt issuances and the use of proceeds thereof to repay in full the prior secured credit facility, the liens securing the 10.5% Senior Notes were released on April 3, 2012 and a collateral suspension is currently in effect. The indenture governing the 10.5% Senior Notes also provides that if, after any such collateral suspension, the aggregate principal amount of our total secured indebtedness, other than the 10.5% Senior Notes due 2017, were to exceed the greater of \$375.0 million and 15.0% of our consolidated tangible assets, as

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defined in such indenture, then the collateral obligations of the Company and guarantors thereunder will be reinstated and must be complied with within 30 days of such event.

The 10.5% Senior Notes are guaranteed by each of the Guarantors that guarantee our obligations under our Credit Agreement.

In 2008, we issued \$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, 2012, \$68.3 million notional amount of the \$250.0 million 3.375% Convertible Senior Notes was outstanding.

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 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, 2012, the number of conversion shares potentially issuable in relation to our 3.375% Convertible Senior Notes was 1.4 million. We may redeem the 3.375% Convertible Senior 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.

We determined that upon maturity or redemption, we have the intent and ability to settle the principal amount of our 3.375% Convertible Senior Notes in cash, and any additional conversion consideration spread (the excess of conversion value over face value) in shares of our Common Stock.

In May 2012, we repurchased a portion of the 3.375% Convertible Senior Notes and 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 Credit Agreement as well as the indentures governing the 7.125% Senior Secured Notes, 10.25% Senior Notes, 10.5% Senior Notes and 3.375% Convertible Senior Notes contain customary events of default. In addition, the Credit Agreement as well as the indentures governing the 7.125% Senior Secured Notes, 10.25% Senior Notes, 10.5% Senior Notes and 3.375% Convertible Senior Notes also contain a provision under which an event of default by the Company or by any restricted subsidiary on any other indebtedness exceeding \$25.0 million would be considered an event of default under the Credit Agreement and indentures 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.

The Credit Agreement as well as the indentures governing the 7.125% Senior Secured Notes, 10.25% Senior Notes and 10.5% Senior Notes contain 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 affiliates; and
- consolidate, merge or transfer all or substantially all of our assets.

During the twelve months ended December 31, 2012, we incurred the following charges which are included in Loss on Extinguishment of Debt in the Consolidated Statements of Operations:

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In April 2012 and in connection with the termination of the prior secured credit facility, we recognized a pretax charge of \$1.4 million, \$0.9 million, net of tax, for the write off of unamortized issuance costs related to the term loan; In April 2012, we recognized a pretax charge of \$6.4 million, \$4.2 million net of tax, related to our debt refinancing; and

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In May 2012, we repurchased \$27.6 million aggregate principal amount of the 3.375% Convertible Senior Notes, resulting in a loss of \$1.3 million, or \$0.9 million, net of tax.

The fair value of our 3.375% Convertible Senior Notes, 10.25% Senior Notes, 10.5% Senior Notes, 7.125% Senior Secured Notes and former 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. The inputs used to determine fair value are considered level two inputs. The following table provides the carrying value and fair value of our long-term debt instruments:

	December 31, 2012		December 31, 2011	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in millions)			
Term Loan Facility (Terminated April 2012)	n/a	n/a	\$452.9	\$442.0
7.125% Senior Secured Notes, due April 2017	\$300.0	\$317.1	n/a	n/a
10.5% Senior Notes, due October 2017	294.5	326.6	293.7	291.2
10.25% Senior Notes, due April 2019	200.0	219.6	n/a	n/a
3.375% Convertible Senior Notes, due June 2038	67.1	68.5	90.2	84.7
7.375% Senior Notes, due April 2018	3.5	3.3	3.5	2.8

We maintain insurance coverage that includes coverage for physical damage, third party liability, workers' compensation and employer's liability, general liability, vessel pollution and other coverages.

In April 2012, we completed the annual renewal of all of our key insurance policies. Our primary marine package provides for hull and machinery coverage for substantially all of our rigs and liftboats up to a scheduled value of each asset. The total maximum amount of coverage for these assets is \$1.6 billion. The marine package includes protection and indemnity and maritime employer's liability coverage for marine crew personal injury and death and certain operational liabilities, with primary coverage (or self-insured retention for maritime employer's liability coverage) of \$5.0 million per occurrence with excess liability coverage up to \$200.0 million. The marine package policy also includes coverage for personal injury and death of third parties with primary and excess coverage of \$25.0 million per occurrence with additional excess liability coverage up to \$200.0 million, subject to a \$250,000 per-occurrence deductible. The marine package also provides coverage for cargo and charterer's legal liability. The marine package includes limitations for coverage for losses caused in U.S. Gulf of Mexico named windstorms, including an annual aggregate limit of liability of \$75.0 million for property damage and removal of wreck liability coverage. We also procured an additional \$75.0 million excess policy for removal of wreck and certain third-party liabilities incurred in U.S. Gulf of Mexico named windstorms. Deductibles for events that are not caused by a U.S. Gulf of Mexico named windstorm are 12.5% of the insured drilling rig values per occurrence, subject to a minimum of \$1.0 million, and \$1.0 million per occurrence for liftboats. The deductible for drilling rigs and liftboats in a U.S. Gulf of Mexico named windstorm event is \$25.0 million. Vessel pollution is covered under a Water Quality Insurance Syndicate policy ("WQIS Policy") providing limits as required by applicable law, including the Oil Pollution Act of 1990. The WQIS Policy covers pollution emanating from our vessels and drilling rigs, with primary limits of \$5.0 million (inclusive of a \$3.0 million per-occurrence deductible) and excess liability coverage up to \$200.0 million.

Control-of-well events generally include an unintended flow from the well that cannot be contained by equipment on site (e.g., a blow-out preventer), by increasing the weight of the drilling fluid, or that does not naturally close itself off through what is typically described as "bridging over". We carry a contractor's extra expense policy with \$25.0 million primary liability coverage for well control costs, expenses incurred to redrill wild or lost wells and pollution, with excess liability coverage up to \$200.0 million for pollution liability that is covered in the primary policy. The policies are subject to exclusions, limitations, deductibles, self-insured retention and other conditions. In addition to the marine package, we have separate policies providing coverage for onshore foreign and domestic general liability, employer's liability, auto liability and non-owned aircraft liability, with customary deductibles and coverage.

Our drilling contracts provide for varying levels of indemnification from our customers and in most cases, may require us to indemnify our customers for certain liabilities. Under our drilling contracts, liability with respect to personnel and property is customarily assigned on a “knock-for-knock” basis, which means that we and our customers assume liability for our respective personnel and property, regardless of how the loss or damage to the personnel and property may be caused. Our customers typically assume responsibility for and agree to indemnify us from any loss or liability resulting from pollution or contamination, including clean-up and removal and third-party damages arising from operations under the contract and originating below the surface of the water, including as a result of blow-outs or cratering of the well (“Blowout Liability”). The customer’s assumption for Blowout Liability may, in certain circumstances, be limited or could be determined to be

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unenforceable in the event of our gross negligence, willful misconduct or other egregious conduct. In addition, we may not be indemnified for statutory penalties and punitive damages relating to such pollution or contamination events. We generally indemnify the customer for the consequences of spills of industrial waste or other liquids originating solely above the surface of the water and emanating from our rigs or vessels.

We are self-insured for the deductible portion of our insurance coverage. Management believes adequate accruals have been made on known and estimated exposures up to the deductible portion of our insurance coverage.

Management believes that claims and liabilities in excess of the amounts accrued are adequately insured. 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. In addition, there is no assurance of renewal or the ability to obtain coverage acceptable to us.

In 2012, in connection with the renewal of certain of our insurance policies, we entered into an agreement to finance a portion of our annual insurance premiums. Approximately \$30.1 million was financed through this arrangement with an interest rate of 3.54% and a maturity date of March 2013, of which \$9.1 million was outstanding at December 31, 2012. There was \$5.2 million outstanding in insurance notes payable at December 31, 2011 which we fully paid during 2012.

Capital Expenditures

We currently expect capital expenditures and drydocking during 2013 to approximate \$130.0 million to \$140.0 million. Planned capital expenditures include items related to general maintenance, regulatory, refurbishment, upgrades and contract specific modifications to our rigs and liftboats. Changes in timing of certain planned capital expenditure projects may result in a shift of spending levels beyond 2013. This estimate includes our capital investment to complete the reactivation of Hercules 209. Should we elect to reactivate additional cold stacked rigs or upgrade and refurbish additional selected rigs or liftboats, our capital expenditures will increase. Reactivations, upgrades and refurbishments are subject to our discretion and will depend on our view of market conditions and our cash flows.

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. If we acquire additional assets, we would expect that our ongoing capital expenditures as a whole would increase in order to maintain our equipment in a competitive condition.

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, bank guarantees, 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, 2012:

Contractual Obligations and Contingent Commitments	Payments due by Period				Total
	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years	
	(In thousands)				
Recorded Obligations:					
Long-term debt obligations	\$68,301	\$—	\$600,000	\$203,508	\$871,809
Insurance notes payable	9,123	—	—	—	9,123
Interest on debt and notes payable(a)	17,367	—	—	—	17,367
Purchase obligations(b)	11,331	—	—	—	11,331
Other	2,756	—	—	—	2,756
Unrecorded Obligations(c):					
Interest on debt and notes payable(a)	58,552	149,444	138,758	31,843	378,597

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Surety bonds, letters of credit and bank guarantees	3,062	—	—	—	3,062
Management compensation obligations	4,933	9,866	—	—	14,799
Purchase obligations(b)	13,025	—	—	—	13,025
Operating lease obligations	3,945	5,803	4,288	—	14,036
Total contractual obligations	\$192,395	\$165,113	\$743,046	\$235,351	\$1,335,905

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(a) Estimated interest is based on the rates associated with the respective fixed rate instrument.

(b) 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.

(c) Tax liabilities of \$7.5 million have been excluded from the table above as a reasonably reliable estimate of the period of cash settlement cannot be made.

Off-Balance Sheet Arrangements

Guarantees

Substantially all of our domestic subsidiaries guarantee the obligations under the Credit Agreement, the 7.125% Senior Secured Notes, the 10.25% Senior Notes and the 10.5% Senior Notes.

Our obligations under the Credit Agreement and 7.125% Senior Secured Notes are secured by liens on a majority of our vessels and substantially all of our other personal property.

Accounting Pronouncements

In May 2011, the FASB issued Accounting Standards Update (“ASU”) No. 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs (“ASU 2011-04”), which changes the wording used to describe many of the requirements in U.S. GAAP for measuring fair value and disclosing information about fair value measurements. Some of the amendments clarify the FASB’s intent about the application of existing fair value measurement requirements while other amendments change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. The amendments in this ASU are effective prospectively for interim and annual periods beginning after December 15, 2011, with no early adoption permitted. We adopted this standard as of January 1, 2012 with no material impact on our consolidated 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, as amended (the "Securities Act"), 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 intend, contemplate, estimate, 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 international contracts, or enter into new contracts, when such contracts expire;
- demand for our rigs and our liftboats;
- activity levels of our customers and their expectations of future energy prices and ability to obtain drilling permits in an efficient manner or at all;
- sufficiency and availability of funds for required capital expenditures, working capital and debt service;
- levels of reserves for accounts receivable;
- success of our plans to dispose of certain assets;
- our ability to close the sale and purchase of assets on time, including the Ben Avon and Titan 2;
  - expected completion times for our repair, refurbishment and upgrade projects, including the upgrade project for Hercules 266, which we recently acquired;
- our ability to complete our shipyard projects incident free;
- our ability to complete our shipyard projects on time to avoid cost overruns and contract penalties;
- our ability to effectively reactivate rigs that we have stacked;
  - the timing and cost of shipyard projects and refurbishments and the return of idle rigs to work;
- our plans to increase international operations;

• expected useful lives of our rigs and liftboats;

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

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

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

the existence of insurance coverage and the extent of recovery from our insurance underwriters for claims made under our insurance policies; and

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

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:

- the ability of our customers in the U.S. Gulf of Mexico to obtain drilling permits in an efficient manner or at all;
- oil and natural gas prices and industry expectations about future prices;
- levels of oil and gas exploration and production spending;
- demand for and supply of 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, North Africa, West Africa and other oil and natural gas producing regions or acts of terrorism or piracy;
- the impact of governmental laws and regulations, including new laws and regulations in the U.S. Gulf of Mexico arising out of the Macondo well blowout incident;
- 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 and rising cost of labor;
- labor relations and work stoppages, particularly in the West African labor environment;
- 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, investigations, 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 rate borrowings. 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.

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## Fair Value of Warrants and Derivative Asset

At December 31, 2012, the fair value of derivative instruments was \$4.0 million. We estimate the fair value of these instruments using a Monte Carlo simulation which takes into account a variety of factors including the strike price, the target price, the stock value, the expected volatility, the risk-free interest rate, the expected life of warrants, and the number of warrants. We are required to revalue this asset each quarter. We believe that the assumption that has the greatest impact on the determination of fair value is the closing price of Discovery Offshore's stock. The following table illustrates the potential effect on the fair value of the derivative asset from changes in the assumptions made:

	Increase/(Decrease)	
	(In thousands)	
25% increase in stock price	\$2,333	
50% increase in stock price	4,923	
10% increase in assumed volatility	826	
25% decrease in stock price	(1,927	)
50% decrease in stock price	(3,273	)
10% decrease in assumed volatility	(962	)

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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, 2012 and 2011, and the related consolidated statements of operations, comprehensive loss, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2012. Our audits also included the financial statement schedule listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule 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, 2012 and 2011, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Hercules Offshore, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2013 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP  
Houston, Texas  
February 28, 2013

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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, 2012, 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, 2012, 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, 2012 and 2011 and the related consolidated statements of operations, comprehensive loss, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2012 of Hercules Offshore, Inc. and subsidiaries and our report dated February 28, 2013 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas

February 28, 2013

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES  
 CONSOLIDATED BALANCE SHEETS  
 (In thousands, except par value)

	December 31, 2012	2011
<b>ASSETS</b>		
Current Assets:		
Cash and Cash Equivalents	\$259,193	\$134,351
Restricted Cash	2,027	9,633
Accounts Receivable, Net of Allowance for Doubtful Accounts of \$788 and \$11,460 as of December 31, 2012 and December 31, 2011, Respectively	167,936	153,688
Prepays	16,135	16,352
Current Deferred Tax Asset	21,125	15,543
Other	12,191	20,435
	478,607	350,002
Property and Equipment, Net	1,462,755	1,591,791
Equity Investment	38,191	34,735
Other Assets, Net	37,077	30,176
	\$2,016,630	\$2,006,704
<b>LIABILITIES AND STOCKHOLDERS' EQUITY</b>		
Current Liabilities:		
Short-term Debt and Current Portion of Long-term Debt	\$67,054	\$22,130
Accounts Payable	58,615	49,370
Accrued Liabilities	82,781	70,421
Interest Payable	17,367	9,899
Insurance Notes Payable	9,123	5,218
Other Current Liabilities	26,483	18,366
	261,423	175,404
Long-term Debt, Net of Current Portion	798,013	818,146
Deferred Income Taxes	56,821	83,503
Other Liabilities	17,611	21,098
Commitments and Contingencies		
Stockholders' Equity:		
Common Stock, \$0.01 Par Value; 300,000 and 200,000 Shares Authorized, Respectively; 160,708 and 139,798 Shares Issued, Respectively; 158,628 and 137,899 Shares Outstanding, Respectively	1,607,607	1,398
Capital in Excess of Par Value	2,159,744	2,057,824
Treasury Stock, at Cost, 2,080 Shares and 1,899 Shares, Respectively	(53,100)	(52,184)
Retained Deficit	(1,225,489)	(1,098,485)
	882,762	908,553
	\$2,016,630	\$2,006,704

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

Table of ContentsHERCULES OFFSHORE, INC. AND SUBSIDIARIES  
CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

	Year Ended December 31,		
	2012	2011	2010
Revenue	\$709,792	\$655,358	\$624,827
Costs and Expenses:			
Operating Expenses	438,084	444,332	403,829
Asset Impairment	108,216	—	122,717
Depreciation and Amortization	166,426	172,571	185,712
General and Administrative	60,643	57,204	55,996
	773,369	674,107	768,254
Operating Loss	(63,577	) (18,749	) (143,427
Other Income (Expense):			
Interest Expense	(79,172	) (79,178	) (80,482
Loss on Extinguishment of Debt	(9,156	) —	—
Other, Net	1,896	(3,934	) 3,876
Loss Before Income Taxes	(150,009	) (101,861	) (220,033
Income Tax Benefit	23,005	35,341	87,940
Loss from Continuing Operations	(127,004	) (66,520	) (132,093
Loss from Discontinued Operations, Net of Taxes	—	(9,608	) (2,501
Net Loss	\$(127,004	) \$(76,128	) \$(134,594
Basic and Diluted Loss Per Share:			
Loss from Continuing Operations	\$(0.83	) \$(0.51	) \$(1.15
Loss from Discontinued Operations	—	(0.07	) (0.02
Net Loss	\$(0.83	) \$(0.58	) \$(1.17
Basic and Diluted Weighted Average Shares Outstanding	153,722	130,474	114,753

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

Table of ContentsHERCULES OFFSHORE, INC. AND SUBSIDIARIES  
CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

(In thousands)

	Year Ended December 31,		
	2012	2011	2010
Net Loss	\$(127,004	) \$(76,128	) \$(134,594
Other Comprehensive Income, Net of Taxes:			
Reclassification of Losses Related to Hedge Transactions Included in	—	—	5,773
Net Income			
Comprehensive Loss	\$(127,004	) \$(76,128	) \$(128,821

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

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES  
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY  
(In thousands)

	December 31, 2012		December 31, 2011		December 31, 2010	
	Shares	Amount	Shares	Amount	Shares	Amount
<b>Common Stock:</b>						
Balance at Beginning of Period	139,798	\$1,398	116,336	\$1,163	116,154	\$1,162
Issuance of Common Stock, Net	20,000	200	22,321	223	—	—
Other	910	9	1,141	12	182	1
Balance at End of Period	160,708	1,607	139,798	1,398	116,336	1,163
<b>Capital in Excess of Par Value:</b>						
Balance at Beginning of Period	—	2,057,824	—	1,924,659	—	1,921,037
Issuance of Common Stock, Net	—	96,496	—	126,562	—	—
Compensation Expense Recognized	—	6,243	—	5,283	—	4,431
Excess Tax Deficit From Stock-Based Arrangements, Net	—	(1,106 )	—	(321 )	—	(826 )
Other	—	287	—	1,641	—	17
Balance at End of Period	—	2,159,744	—	2,057,824	—	1,924,659
<b>Treasury Stock:</b>						
Balance at Beginning of Period	(1,899 )	(52,184 )	(1,552 )	(50,333 )	(1,504 )	(50,151 )
Repurchase of Common Stock	(181 )	(916 )	(347 )	(1,851 )	(48 )	(182 )
Balance at End of Period	(2,080 )	(53,100 )	(1,899 )	(52,184 )	(1,552 )	(50,333 )
<b>Accumulated Other Comprehensive Loss:</b>						
Balance at Beginning of Period	—	—	—	—	—	(5,773 )
Other Comprehensive Income, Net of Taxes	—	—	—	—	—	5,773
Balance at End of Period	—	—	—	—	—	—
<b>Retained Deficit:</b>						
Balance at Beginning of Period	—	(1,098,485 )	—	(1,022,357 )	—	(887,763 )
Net Loss	—	(127,004 )	—	(76,128 )	—	(134,594 )
Balance at End of Period	—	(1,225,489 )	—	(1,098,485 )	—	(1,022,357 )
<b>Total Stockholders' Equity</b>	<b>158,628</b>	<b>882,762</b>	<b>137,899</b>	<b>908,553</b>	<b>114,784</b>	<b>853,132</b>

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

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES  
CONSOLIDATED STATEMENTS OF CASH FLOWS  
(In thousands)

	Year Ended December 31,		
	2012	2011	2010
Cash Flows from Operating Activities:			
Net Loss	\$(127,004	) \$(76,128	) \$(134,594
Adjustments to Reconcile Net Loss to Net Cash Provided by Operating Activities:			
Depreciation and Amortization	166,426	174,227	191,183
Stock-Based Compensation Expense	6,243	5,283	4,431
Deferred Income Taxes	(33,236	) (59,187	) (98,468
Provision (Benefit) for Doubtful Accounts Receivable	(8,847	) (13,623	) 182
Amortization of Deferred Financing Fees	3,174	3,871	3,302
Amortization of Original Issue Discount	4,122	4,433	4,078
Gain on Insurance Settlement	(30,668	) —	—
Gain on Disposal of Assets, Net	(33,396	) (10,079	) (14,345
Non-Cash Portion of Loss on Extinguishment of Debt	2,738	—	—
Asset Impairment	108,216	—	125,136
Other	(1,776	) 3,245	(401
(Increase) Decrease in Operating Assets —			
Accounts Receivable	(7,901	) 22,072	(10,316
Prepaid Expenses and Other	11,646	23,144	22,193
Increase (Decrease) in Operating Liabilities —			
Accounts Payable	9,976	(16,325	) 411
Insurance Notes Payable	(26,193	) (26,547	) (25,438
Other Current Liabilities	28,453	9,377	(28,994
Other Liabilities	(3,610	) 8,262	(13,940
Net Cash Provided by Operating Activities	68,363	52,025	24,420
Cash Flows from Investing Activities:			
Acquisition of Assets	(40,000	) (25,000	) —
Additions of Property and Equipment	(127,180	) (39,483	) (22,018
Deferred Drydocking Expenditures	(11,425	) (15,739	) (15,040
Cash Paid for Equity Investment	(4,288	) (34,155	) —
Insurance Proceeds Received	54,139	—	—
Proceeds from Sale of Assets, Net	72,897	80,362	23,222
(Increase) Decrease in Restricted Cash	3,588	1,495	(7,470
Net Cash Used in Investing Activities	(52,269	) (32,520	) (21,306
Cash Flows from Financing Activities:			
Long-term Debt Borrowings	500,000	—	—
Long-term Debt Repayments	(452,909	) (22,247	) (7,695
Redemption of 3.375% Convertible Senior Notes	(27,606	) —	—
Common Stock Issuance	96,696	—	—
Payment of Debt Issuance Costs	(7,717	) (2,109	) —
Other	284	2,536	419
Net Cash Provided By (Used in) Financing Activities	108,748	(21,820	) (7,276
Net Increase (Decrease) in Cash and Cash Equivalents	124,842	(2,315	) (4,162
Cash and Cash Equivalents at Beginning of Period	134,351	136,666	140,828

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Cash and Cash Equivalents at End of Period	\$259,193	\$134,351	\$136,666
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The accompanying notes are an integral part of these financial statements.

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES  
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Business

Organization

Hercules Offshore, Inc., a Delaware corporation, and its majority owned subsidiaries (the “Company”) provide 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 and International Liftboats segments (See Note 16). At December 31, 2012, the Company owned a fleet of 37 jackup rigs, 14 barge rigs and 58 liftboat vessels and operated an additional five liftboat vessels owned by a third party. 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 in several key shallow-water provinces around the world.

2. Significant Accounting Policies

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.

Use of Estimates

In preparing financial statements in conformity with accounting principles generally accepted in the United States, management makes estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements, as well as the reported amounts of revenue and expenses during the reporting period. On an ongoing basis, the Company evaluates its estimates, including those related to bad debts, investments, derivatives, property and equipment, income taxes, insurance, percentage-of-completion, employment benefits and contingent liabilities. The Company bases its 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.

Cash and Cash Equivalents

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

Restricted Cash

The Company’s restricted cash balance supports surety bonds related to the Company’s U.S. operations.

Revenue Recognition

Revenue generated from the Company’s contracts is recognized as services are performed, as long as collectability is reasonably assured. For certain contracts, the Company may receive lump-sum fees for the mobilization of equipment and personnel. Mobilization fees received and costs incurred to mobilize a rig from one location to another under contracts longer than ninety days are recognized as services are performed over the term of the related drilling contract. For certain contracts, the Company may receive fees from its customers for capital improvements to its rigs. Such fees are deferred and recognized as services are performed over the term of the related contract. The Company capitalizes such capital improvements and depreciates them over the useful life of the asset. Certain of the Company's contracts also allow us to recover additional direct costs, such as demobilization costs, additional labor and additional catering costs and 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.

Additionally, the initial fair value of the warrants and 500,000 shares issued from Discovery Offshore S.A. (“Discovery Offshore”) have been recorded as deferred revenue to be amortized over 30 years, the estimated useful life of the two new-build Discovery Offshore rigs.

Percentage-of-Completion

In addition to having an equity method investment in Discovery Offshore, the Company has a construction management agreement (the “Construction Management Agreement”) and a services agreement (the “Services Agreement”) with Discovery Offshore with respect to each of the Rigs that Discovery Offshore has under construction (See Note 16). Under the Construction

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Management Agreements, the Company is planning, supervising and managing the construction and commissioning of the Rigs in exchange for a fixed fee of \$7.0 million per Rig, which the Company initially received and recorded as deferred revenue in February 2011. The Company is using the percentage-of-completion method of accounting for its revenue and related costs associated with its construction management agreements with Discovery Offshore, combining the construction management agreements, based on a cost-to-cost method. Any revisions in revenue, cost or the progress towards completion, will be treated as a change in accounting estimate and will be accounted for using the cumulative catch-up method.

Stock-Based Compensation

The Company recognizes compensation cost for all share-based payments awarded in accordance with Financial Accounting Standards Board (“FASB”) Accounting Standards Codification (“ASC”) 718, Compensation — Stock Compensation (“ASC 718”) and in accordance with such the Company records the grant date fair value of stock options and time-based restricted stock awarded as compensation expense using a straight-line method over the requisite service period. Performance based awards are recognized using the accelerated method over the requisite service period. The Company estimates 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). The fair value of the Company’s time-based restricted stock and performance based grants that are share settled is based on the closing price of the Company’s common stock on the date of grant. For those performance based grants that contain a market performance condition, the Monte Carlo simulation is used for valuation as of the date of grant. All of the Company’s cash settled awards are recorded as a liability at fair value, which is remeasured at the end of each reporting period, over the requisite service period. The Company’s cash settled liability awards that contain market performance conditions are valued using a Monte Carlo simulation, while the service based liability retention award is valued based on the lesser of the average price of the Company’s common stock for the 90 days prior to the end of the quarter or date of vesting and \$10.00. The Company also estimates future forfeitures and related tax effects. The Company’s 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.

Due to the uncertainty in the level of awards to be granted in the future as well as changes in the fair value of liability-based awards, the Company's estimate of future expense relating to stock options, restricted stock and liability-based awards granted through December 31, 2012 as well as the remaining vesting period over which the associated expense is to be recognized are estimates and subject to change.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are stated at the historical carrying amount net of write-offs and the allowance for doubtful accounts. The Company monitors the accounts receivable from its customers for 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. The Company establishes an allowance for doubtful accounts based on the actual amount it believes is not collectable. The Company had an allowance of \$0.8 million and \$11.5 million at December 31, 2012 and 2011, respectively. The change in the Company’s allowance during the year ended December 31, 2012 related primarily to payments received from a customer in its International Offshore segment.

Business Combinations

The Company accounted for the 2011 Seahawk Transaction as a business combination (See Note 5).

Property and Equipment

Property and equipment are stated at cost, less accumulated depreciation. Expenditures for property and equipment and items that substantially increase the useful lives of existing assets are capitalized at cost and depreciated. Expenditures for drydocking the Company’s liftboats are capitalized at cost in Other Assets, Net on the Consolidated Balance Sheets and amortized on the straight-line method over a period of 12 months. Drydocking costs, net of

accumulated amortization, at December 31, 2012 and 2011 were \$3.7 million and \$5.2 million, respectively. Amortization expense for drydocking costs was \$13.0 million, \$16.2 million and \$14.0 million for the years ended December 31, 2012, 2011 and 2010, respectively, of which \$0.4 million and \$0.5 million related to the Company's former Delta Towing segment and is included in Loss from Discontinued Operations, Net of Taxes in the Consolidated Statements of Operations for the years ended December 31, 2011 and 2010, respectively. Routine expenditures for repairs and maintenance are expensed as incurred.

Depreciation is computed using the straight-line method, after allowing for salvage value where applicable, over the useful lives of the assets. Depreciation of leasehold improvements is computed utilizing the straight-line method over the lease term or life of the asset, whichever is shorter.

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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The useful lives of property and equipment for the purposes of computing depreciation are as follows:

	Years
Drilling rigs and marine equipment (salvage value of 10%)	15
Drilling machinery and equipment	3–12
Furniture and fixtures	3
Computer equipment	3–7
Automobiles and trucks	3

The carrying value of long-lived assets, principally property and equipment, is reviewed for potential impairment when events or changes in circumstances indicate that the carrying amount of such assets 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 upon the estimated undiscounted future net cash flows of the related asset or group of assets being evaluated. Actual impairment charges are recorded using an estimate of discounted future cash flows. This evaluation requires the Company to make judgments regarding long-term forecasts of future revenue and costs. In turn these forecasts are uncertain in that they require assumptions about demand for the Company's 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 the Company's ability to contract its rigs and vessels at economical rates. During periods of an oversupply, it is not uncommon for the Company to have rigs or vessels idled for extended periods of time, which could indicate that an asset group may be impaired. The Company's rigs and vessels are mobile units, equipped to operate in geographic regions throughout the world and, consequently, the Company 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, the Company's rigs and vessels are considered to be interchangeable within classes or asset groups and accordingly, the Company performs its impairment evaluation by asset group.

The Company's estimates, assumptions and judgments used in the application of its 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 the Company's 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 the Company's 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. The Company evaluates the remaining useful lives of its rigs and vessels when certain events occur that directly impact its assessment of the remaining useful lives of the rigs and vessels and include changes in operating condition, functional capability and market and economic factors. The Company also considers 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 and salvage values of individual rigs and vessels.

When analyzing its assets for impairment, the Company separates its marketable assets, those assets that are actively marketed and can be warm stacked or cold stacked for short periods of time depending on market conditions, from its non-marketable assets, those assets that have been cold stacked for an extended period of time or those assets that the Company currently does not reasonably expect to market in the foreseeable future.

#### Equity Investments

The Company has an equity investment in Discovery Offshore, a pure-play, ultra high-specification jackup drilling company with two rigs currently under construction. The Company's total investment in Discovery Offshore was \$38.2 million, or 32%, and \$34.7 million, or 28%, as of December 31, 2012 and 2011, respectively, and is being accounted for using the equity method of accounting as the Company has the ability to exert significant influence, but not control, over operating and financial

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

policies. The Company reviews its equity investments for impairment whenever there is a loss in value of an investment which is considered to be other than temporary. In addition, the Company was also issued warrants to purchase up to 5.0 million additional shares of Discovery Offshore as additional compensation for its costs incurred and efforts expended in forming Discovery Offshore that, if exercised, would be recorded as an increase in the Company's equity investment in Discovery Offshore (See Notes 11 and 12).

Derivatives

The warrants issued to the Company from Discovery Offshore are being accounted for as a derivative instrument as the underlying security is readily convertible to cash. Subsequent changes in the fair value of the warrants are recognized in other income (expense). The fair value of the Discovery Offshore warrants was determined using a Monte Carlo simulation (See Note 12). The Company's estimate of fair value requires a number of inputs and changes to those inputs could result in a different valuation.

Deferred Financing Fees

Financing fees are deferred and amortized over the life of the applicable debt instrument. However, in the event of an early repayment of debt or certain debt amendments, the related unamortized deferred financing fees are expensed in connection with the repayment or amendment (See Note 10). Unamortized deferred financing fees at December 31, 2012 and 2011 were \$12.1 million and \$9.1 million, respectively. Amortization expense for financing fees was \$3.2 million, \$3.9 million and \$3.3 million for the years ended December 31, 2012, 2011 and 2010, respectively, and is included in Interest Expense on the Consolidated Statements of Operations.

Accrued Self-Insurance Reserves

The Company is self-insured up to certain retention limits for maritime employer's liability claims and protection and indemnity claims. The amounts in excess of the self-insured levels are fully insured, up to a limit. Self-insurance reserves are based on estimates of (i) claims reported and (ii) loss amounts incurred but not reported. Reserves for reported claims are estimated by the Company's internal risk department by evaluating the facts and circumstances of each claim and are adjusted from time to time based upon the status of each claim and the Company's historical experience with similar claims. Reserves for loss amounts incurred but not reported are estimated by the Company's third-party actuary and include provisions for expected development on claims reported due to information not yet received and expected development on claims to be reported in the future but which have occurred prior to the accounting date. As of December 31, 2012 and 2011, there was \$27.9 million and \$22.1 million in Accrued Self-Insurance Reserves, respectively, which is included in Accrued Liabilities on the Consolidated Balance Sheets. The actual outcome of any claim could differ significantly from estimated amounts.

Income Taxes

The Company uses the liability method for determining its income taxes. The Company's income tax provision is based upon the tax laws and rates in effect in the countries in which the Company's operations are conducted and income is earned. The income tax rates imposed and methods of computing taxable income in these jurisdictions vary substantially. The Company's effective tax rate is expected to fluctuate from year to year as operations are conducted in different taxing jurisdictions and the amount of pre-tax income fluctuates. Current income tax expense reflects an estimate of the Company's income tax liability for the current year, withholding taxes, changes in prior year tax estimates as returns are filed, or from tax audit adjustments, while the net deferred tax expense or benefit represents the changes in the balance of deferred tax assets and liabilities as reported on the balance sheet.

Valuation allowances are established to reduce deferred tax assets when it is more likely than not that some portion or all of the deferred tax assets will not be realized in the future. The Company currently does not have any valuation allowances related to the tax assets. While the Company has considered estimated future taxable income and ongoing prudent and feasible tax planning strategies in assessing the need for a valuation allowance, changes in these estimates and assumptions, as well as changes in tax laws, could require the Company to record or adjust the valuation allowance for deferred taxes in the future. These adjustments to the valuation allowance would impact the Company's income tax provision in the period in which such adjustments are identified and recorded.

Certain of the Company's international rigs and liftboats are owned or operated, directly or indirectly, by the Company's wholly owned Cayman Islands subsidiaries. Most of the earnings from these subsidiaries are reinvested internationally and remittance to the United States is indefinitely postponed. In certain circumstances, management expects that, due to the changing demands of the offshore drilling and liftboat markets and the ability to redeploy the Company's offshore units, certain of such units will not reside in a location long enough to give rise to future tax consequences in that location. As a result, no deferred tax asset or liability has been recognized in these circumstances. Should management's expectations change regarding

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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

the length of time an offshore drilling unit will be used in a given location, the Company would adjust deferred taxes accordingly.

**Earnings Per Share**

The Company calculates basic earnings per share by dividing net income by the weighted average number of shares outstanding. Diluted earnings per share is computed by dividing net income by the weighted average number of shares outstanding during the period as adjusted for the dilutive effect of the Company's stock option and restricted stock awards. The effect of stock option and restricted stock awards is not included in the computation for periods in which a net loss occurs, because to do so would be anti-dilutive. Stock equivalents of 5.9 million, 6.5 million and 6.3 million were anti-dilutive and are excluded from the calculation of the dilutive effect of stock equivalents for the diluted earnings per share calculations for the years ended December 31, 2012, 2011 and 2010, respectively. There were no stock equivalents to exclude from the calculation of the dilutive effect of stock equivalents for the diluted earnings per share calculations for the years ended December 31, 2012, 2011 and 2010 related to the assumed conversion of the 3.375% Convertible Senior Notes as there was no excess of conversion value in any of these periods.

**3. Accounting Pronouncements**

In May 2011, the FASB issued Accounting Standards Update ("ASU") No. 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs ("ASU 2011-04"), which changes the wording used to describe many of the requirements in U.S. GAAP for measuring fair value and disclosing information about fair value measurements. Some of the amendments clarify the FASB's intent about the application of existing fair value measurement requirements while other amendments change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. The amendments in this ASU are effective prospectively for interim and annual periods beginning after December 15, 2011, with no early adoption permitted. The Company adopted this standard as of January 1, 2012 with no material impact on its consolidated financial statements.

**4. Property and Equipment, Net**

The following is a summary of property and equipment, at cost, less accumulated depreciation:

	December 31,	
	2012	2011
	(in thousands)	
Drilling rigs and marine equipment	\$2,077,330	\$2,133,045
Drilling machinery and equipment	62,774	75,101
Leasehold improvements	10,263	10,263
Automobiles and trucks	2,467	2,225
Computer equipment	16,054	14,058
Furniture and fixtures	1,303	1,086
Total property and equipment, at cost	2,170,191	2,235,778
Less accumulated depreciation	(707,436 )	(643,987 )
Total property and equipment, net	\$1,462,755	\$1,591,791

Depreciation expense was \$153.4 million, \$157.4 million and \$175.6 million for the years ended December 31, 2012, 2011 and 2010, respectively, of which \$1.2 million and \$5.0 million related to the Company's Delta Towing segment and is included in Loss from Discontinued Operations, Net of Taxes in the Consolidated Statements of Operations for the years ended December 31, 2011 and 2010, respectively.

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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

## 5. Business Combination

On April 27, 2011, the Company completed its acquisition of 20 jackup rigs and related assets, accounts receivable, accounts payable and certain contractual rights from Seahawk Drilling, Inc. and certain of its subsidiaries ("Seahawk") ("Seahawk Transaction") for total consideration of approximately \$150.3 million consisting of \$25.0 million of cash and 22.1 million shares of Hercules common stock, net of a working capital adjustment. Seahawk operated a jackup rig business that provided contract drilling services to the oil and natural gas exploration and production industry in the Gulf of Mexico.

The Seahawk Transaction expanded the Company's jackup fleet and further strengthened the Company's position as a leading shallow-water drilling provider. The fair value of the shares issued was determined using the closing price of the Company's common stock of \$5.68 on April 27, 2011. The results of Seahawk are included in the Company's results from the date of acquisition.

The Company accounted for this transaction as a business combination and accordingly, the total consideration was allocated to Seahawk's net tangible assets based on their estimated fair values. The Company's Financial Statements have been prepared assuming the same characterization applies for income tax purposes, based on the facts in existence through December 31, 2012. Seahawk is in a Chapter 11 proceeding in the U.S. Bankruptcy Court. Subsequent to December 31, 2012, at the direction of the Court, Seahawk made certain distributions to its equity holders. These distributions, taken together with other aspects of the acquisition, will change the tax treatment and will cause the Seahawk Transaction to be characterized as a reorganization pursuant to IRC §368(a)(1)(G) (See Note 15).

The allocation of the consideration was as follows:

	April 27, 2011
	(In thousands)
Accounts Receivable	\$15,366
Property and Equipment, Net	145,404
Total Assets	160,770
Accounts Payable	(10,441 )
Total Purchase Price	\$150,329

The following presents the consolidated financial information for the Company on a pro forma basis assuming the Seahawk Transaction had occurred as of the beginning of the periods presented. The historical financial information has been adjusted to give effect to pro forma items that are directly attributable to the acquisition, factually supportable and with respect to income, are expected to have a continuing impact on consolidated results. These items include adjustments to record the incremental depreciation expense related to the increase in fair value of the acquired assets, the elimination of amounts related to the operations of Seahawk that were not purchased in the transaction as well as the elimination of directly related transaction costs.

The unaudited pro forma financial information set forth below has been compiled from historical financial statements and other information, but is not necessarily indicative of the results that actually would have been achieved had the transaction occurred on the dates indicated or that may be achieved in the future:

	Year Ended December 31,	
	2011	2010
	(In millions, except per share amounts)	
Revenue	\$688.8	\$699.6
Net Loss	(73.8 )	(478.7 )
Basic Loss Per Share	(0.54 )	(3.50 )
Diluted Loss Per Share	(0.54 )	(3.50 )



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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The amount of revenue and net income related to the net assets acquired from Seahawk included in the Company's Consolidated Statements of Operations for the year ended December 31, 2011 is as follows:

	April 27, 2011 through December 31, 2011 (in millions)
Revenue	\$74.4
Net income	18.3

The Company incurred transaction costs in the amount of \$3.6 million for the year ended December 31, 2011 related to the Seahawk Transaction of which \$0.2 million is included in Operating Expenses and \$3.4 million is included in General and Administrative on the Consolidated Statements of Operations.

#### 6. Dispositions and Discontinued Operations

From time to time the Company enters into agreements to sell assets. The following table provides information related to the sale of several of the Company's assets, excluding other miscellaneous asset sales that occur in the normal course of business, during the years ended December 31, 2012, 2011 and 2010:

Asset	Segment	Period of Sale	Proceeds (in thousands)	Gain/(Loss)
2012:				
Hercules 2501	Domestic Offshore	June 2012	\$7,000	\$5,465
Hercules 29	Inland	July 2012	900	770
Platform Rig 3 (a)	International Offshore	August 2012	35,516	18,350
Hercules 101	Domestic Offshore	September 2012	1,200	—
Hercules 252 (b)	Domestic Offshore	October 2012	8,000	—
Hercules 257	Domestic Offshore	November 2012	6,500	2,450
Hercules 259	Domestic Offshore	November 2012	8,000	6,441
Hercules 75	Domestic Offshore	December 2012	650	(911 )
Hercules 77	Domestic Offshore	December 2012	650	(825 )
Hercules 28	Inland	December 2012	600	474
			\$69,016	\$32,214

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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Asset	Segment	Period of Sale	Proceeds (in thousands)	Gain/(Loss)
2011:				
Hercules 78	Domestic Offshore	May 2011	\$1,700	\$20
Various (c)	Delta Towing	May 2011	30,000	(13,359 )
Hercules 152	Domestic Offshore	July 2011	5,000	271
Hercules 190	Domestic Offshore	September 2011	2,000	1,440
Hercules 254	Domestic Offshore	September 2011	2,054	369
Hercules 800	Domestic Offshore	October 2011	1,360	843
Hercules 256	Domestic Offshore	December 2011	6,725	5,151
Hercules 2502	Domestic Offshore	December 2011	6,725	5,151
Hercules 2503	Domestic Offshore	December 2011	5,000	3,460
Hercules 2008	Domestic Offshore	December 2011	1,500	35
			\$62,064	\$3,381
2010:				
Various (d)	Inland	March 2010	\$2,200	\$1,753
Various (d)	Inland	April 2010	800	410
Hercules 191	Domestic Offshore	April 2010	5,000	3,067
Hercules 255	Domestic Offshore	September 2010	5,000	3,180
Hercules 155	Domestic Offshore	December 2010	4,800	3,969
			\$17,800	\$12,379

(a) This represents the gain on the sale of Platform Rig 3 and related legal entities.

(b) During the third quarter of 2012, the Company realized an impairment charge related to the write-down of Hercules 252 (See Note 12).

(c) The Company completed the sale of substantially all of Delta Towing's assets.

(d) The Company entered into an agreement to sell six of its retired barges for \$3.0 million. The sale of three barges closed in each of March and April 2010.

Discontinued Operations

In May 2011, the Company completed the sale of substantially all of Delta Towing's assets and certain liabilities for aggregate consideration of \$30 million in cash (the "Delta Towing Sale") and recognized a loss on the sale of approximately \$13 million. In addition, the Company retained the working capital of its Delta Towing business which was approximately \$6 million at the date of sale. The results of operations of the Delta Towing segment are reflected in the Consolidated Statements of Operations for the two years ended December 31, 2011 as discontinued operations. Interest charges have been allocated to the discontinued operations of the Delta Towing segment in accordance with FASB ASC 205-20, Discontinued Operations. The interest was allocated based on a pro rata calculation of the net Delta Towing assets sold as compared to the Company's consolidated net assets. Interest allocated to discontinued operations was \$0.8 million and \$2.5 million for the years ended December 31, 2011 and 2010, respectively.

Operating results of the Delta Towing segment were as follows:

	Year Ended December 31,	
	2011	2010
	(in thousands)	
Revenue	\$9,822	\$32,653
Loss Before Income Taxes	\$(15,627 )	\$(4,183 )
Income Tax Benefit	6,019	1,682



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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The year ended December 31, 2011 includes a loss of \$13.4 million, or \$8.2 million net of taxes, in connection with the Delta Towing Sale.

The carrying value of the assets included in the Delta Towing Sale are as follows:

	May 13, 2011 (In thousands)
Property and Equipment, Net and Related Assets	\$43,359

## 7. Long-Term Incentive Awards

## Stock-based Compensation

The Company's 2004 Amended and Restated Long-Term Incentive Plan (the "2004 Plan") provides for the granting of stock options, restricted stock, phantom stock, performance stock awards and other stock-based awards to selected employees and non-employee directors of the Company. At December 31, 2012, approximately 6.0 million shares were available for grant or award under the 2004 Plan. The Compensation Committee of the Company's Board of Directors selects participants from time to time and, subject to the terms and conditions of the 2004 Plan, determines all terms and conditions of awards. The Company issues originally issued shares upon exercise of stock options and for restricted stock grants.

The Company has the following equity awards grants under the 2004 Plan:

**Time-based awards** The Company granted time-based restricted stock awards to employees which vest 1/3 per year and time-based restricted stock awards to the Company's Directors which vest on the date of the Company's annual meeting of stockholders that follows the grant date. The grant-date fair value per share for these time-based restricted stock awards is equal to the closing price of the Company's stock on the grant date. Additionally, the Company granted stock options which vest 1/3 per year and have a maximum contractual term of 10 years.

**Objective-based awards** The Company granted additional compensation awards to employees that are based on the Company's achievement of certain Company-based performance objectives as well as the Company's achievement of certain market-based objectives. A portion of these awards are payable in shares of the Company's stock and vest 1/3 per year. If the highest market-based and Company-based performance objectives are met, a portion of these awards are payable in cash and cliff vest at the first anniversary of the grant date. Additionally, the Company granted certain awards to its Chief Executive Officer that are based upon the Company's achievement of certain market-based objectives that, if met, will be payable in cash at the end of the vesting period, ("Performance Retention Awards") as well as a retention award outside of the 2004 Plan payable in cash at the end of a three year vesting equal to the product of 500,000 shares and the lesser of the average stock price of the Company's common stock for the 90 days prior to the date of vesting and \$10.00.

The Company recognized \$2.6 million and \$0.9 million in employee compensation expense and \$0.9 million and \$0.3 million in related income tax benefit for all liability based awards during the years ended December 31, 2012 and 2011, respectively. The Company recognized \$6.2 million, \$5.3 million and \$4.4 million in employee stock-based compensation expense and \$2.2 million, \$1.8 million and \$1.6 million in related income tax benefit for all share-settled awards during the years ended December 31, 2012, 2011 and 2010, respectively. The Company classified thirteen thousand, \$0.9 million and \$0.4 million in excess tax benefits as a financing cash inflow for the years ended December 31, 2012, 2011 and 2010, respectively. The Company's estimate of future expense relating to stock options, restricted stock and liability-based awards granted through December 31, 2012 as well as the remaining vesting period over which the associated expense is to be recognized is presented in the following table:

	December 31, 2012	
Unrecognized Compensation Expense	Weighted Average Remaining Term	
(in thousands)	(in years)	

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Stock Option Awards	\$121	0.2
Time-based Restricted Stock Awards	4,632	1.2
Objective-based Awards (share settled)	1,921	1.2
Objective-based Awards (cash settled)	1,563	0.9

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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The Company uses various assumptions to estimate the fair value of the Company's stock option awards and objective-based awards. The Company uses the historical volatility of its common stock to estimate volatility while the dividend yield assumption was based on historical and anticipated dividend payouts. The risk-free interest rate assumption was based on observed interest rates consistent with the approximate vesting period.

## Objective-based Awards (cash settled)

The Company accounts for awards, or the portion of the awards, requiring cash settlement under stock-compensation principles of accounting as liability instruments. The fair value of all liability instruments are being remeasured based on the awards' estimated fair value at the end of each reporting period and are being recorded to expense over the vesting period. The awards that are based on the Company's achievement of market-based objectives related to the Company's stock price are valued using a Monte Carlo simulation based on the following weighted-average assumptions:

	December 31, 2012		December 31, 2011	
	Performance Retention Awards	Restricted Stock Market-Based	Performance Retention Awards	
Dividend yield	—	—	—	
Expected price volatility	65.0	% 65.0	% 65.0	%
Risk-free interest rate	0.2	% 0.1	% 0.3	%
Stock price	\$6.17	\$6.17	\$4.44	
Fair value	\$3.24	\$6.17	\$1.83	

The stock price represents the closing price of the Company's common stock at the valuation date.

## Stock Option Awards

The fair value of the stock options granted under the 2004 Plan was estimated on the date of grant using the Trinomial Lattice option pricing model with the following assumptions used:

	2010	
Dividend yield	—	
Expected price volatility	45.8	%
Risk-free interest rate	2.7	%
Expected life of options (in years)	6.0	
Weighted-average fair value of options granted	\$1.67	

The Company used the simplified method to estimate the expected life of the options granted. There were no options granted in year ended 2011 or 2012.

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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table summarizes stock option activity under the 2004 Plan as of December 31, 2012 and changes during the year then ended:

Stock Options	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
				(in thousands)
Outstanding at January 1, 2012	3,815,800	\$8.13	6.74	\$4,546
Granted	—	—		
Exercised	(137,579)	1.98		
Forfeited	(8,791)	1.65		
Expired	(84,189)	8.91		
Outstanding at December 31, 2012	3,585,241	8.36	5.78	8,241
Vested or Expected to Vest at December 31, 2012	3,565,041	8.39	5.77	8,175
Exercisable at December 31, 2012	3,193,587	8.93	5.60	7,282

The intrinsic value of stock options exercised during 2012, 2011 and year ended 2010 was \$0.4 million, \$2.3 million and twenty thousand dollars, respectively. Cash received from stock option exercises was \$0.3 million, \$1.7 million and eighteen thousand dollars during the years ended December 31, 2012, 2011 and year ended 2010, respectively.

Objective-based Awards (share settled)

The fair value of all awards requiring share settlement are measured at the fair value on the date of grant. These awards that are based on the Company's achievement of market-based objectives related to the Company's stock price are valued at the date of grant using a Monte Carlo simulation based on the following assumptions:

	February 28, 2012	
Dividend yield	—	
Expected price volatility	65.0	%
Risk-free interest rate	0.2	%
Stock price	\$5.28	
Fair value	\$5.28	

The stock price represents the closing price of the Company's common stock at February 28, 2012.

The following table summarizes information about objective-based restricted stock outstanding as of December 31, 2012 and changes during the year then ended:

	Objective-Based Restricted Stock	Weighted-Average Grant Date Fair Value
Non-Vested at January 1, 2012	596,858	\$5.93
Granted (a)	810,026	5.28
Vested	(198,972)	) 5.93
Forfeited	(41,521)	) 5.28
Non-Vested at December 31, 2012	1,166,391	5.50

(a) The number of objective-based restricted stock shown reflects the shares that would be granted if the maximum level of performance is achieved. The number of shares actually issued may range from zero to 810,026.

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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The weighted-average grant date fair value of objective-based restricted stock granted during the years ended 2012 and 2011 was \$5.28 and \$5.93, respectively. The total fair value of objective-based restricted stock that vested during the year ended 2012 was \$0.9 million. There was no objective-based restricted stock granted in the year ended 2010. In addition, there was no objective-based restricted stock that vested during the years ended 2011 or 2010.

## Time-based Restricted Stock Awards

The following table summarizes information about time-based restricted stock outstanding as of December 31, 2012 and changes during the year then ended:

	Time-Based Restricted Stock	Weighted- Average Grant Date Fair Value
Non-Vested at January 1, 2012	1,375,010	\$4.90
Granted	924,733	5.03
Vested	(563,431	) 4.79
Forfeited	(97,774	) 4.39
Non-Vested at December 31, 2012	1,638,538	5.04

The weighted-average grant date fair value of time-based restricted stock granted during the years ended 2012, 2011 and 2010 was \$5.03, \$5.00 and \$3.79, respectively. The total fair value of time-based restricted stock that vested during the years ended 2012, 2011 and 2010 was \$2.8 million, \$2.4 million and \$0.7 million, respectively.

## 8. Supplemental Financial Information

## Consolidated Balance Sheet Information

Other current assets and other current liabilities consisted of the following:

	December 31,	
	2012	2011
	(in thousands)	
Other:		
Insurance Claims Receivable	\$1,784	\$9,567
Deferred Expense-Current Portion	7,653	3,811
Other	2,754	7,057
	\$12,191	\$20,435
Other Current Liabilities:		
Deferred Revenue-Current Portion	\$14,546	\$8,461
Taxes Payable	4,958	4,763
Other	6,979	5,142
	\$26,483	\$18,366

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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Accrued liabilities consisted of the following:

	December 31, 2012	2011
	(in thousands)	
Accrued Liabilities:		
Taxes other than Income	\$20,463	\$14,899
Accrued Payroll and Employee Benefits	34,066	29,758
Accrued Self-Insurance Reserves	27,947	22,063
Other	305	3,701
	\$82,781	\$70,421

## Common Stock Offering

In March 2012, the Company raised approximately \$96.7 million in net proceeds, after adjusting for underwriting discounts and offering expenses, from an underwritten public offering of 20.0 million shares of common stock, par value \$0.01 per share at a price to the public of \$5.10 per share (\$4.86, net of underwriting discounts). The Company used a portion of the net proceeds from the share offering to fund a portion of the purchase price for the acquisition of Hercules 266 and will use the remaining net proceeds for general corporate purposes as well as the costs associated with the upgrade and mobilization of Hercules 266.

## 9. Benefit Plan

The Company currently has a 401(k) plan in which substantially all U.S. employees are eligible to participate. The Company match was eliminated effective August 1, 2009, but was reinstated effective May 1, 2011 to match participant contributions equal to 3% of a participant's eligible compensation. The Company incurred expense related to matching contributions of \$3.2 million and \$1.6 million for the years ended December 31, 2012 and 2011, respectively. The Company made no matching contributions in the year ended December 31, 2010.

## 10. Debt

Debt is comprised of the following:

	December 31, 2012	December 31, 2011
	(in thousands)	
Term Loan Facility, previously due July 2013	\$—	\$452,909
7.125% Senior Secured Notes, due April 2017	300,000	—
10.5% Senior Notes, due October 2017	294,503	293,676
10.25% Senior Notes, due April 2019	200,000	—
3.375% Convertible Senior Notes, due June 2038	67,054	90,180
7.375% Senior Notes, due April 2018	3,510	3,511
Total Debt	865,067	840,276
Less Short-term Debt and Current Portion of Long-term Debt	67,054	22,130
Total Long-term Debt, Net of Current Portion	\$798,013	\$818,146

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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following is a summary of scheduled long-term debt maturities by year (in thousands):

2013	\$67,054
2014	—
2015	—
2016	—
2017	594,503
Thereafter	203,510
	\$865,067

Liability Component	December 31, 2012			December 31, 2011		
	Notional Amount (in millions)	Unamortized Discount	Carrying Value	Notional Amount (in millions)	Unamortized Discount	Carrying Value
10.5% Senior Notes, due October 2017	\$300.0	\$(5.5)	) \$294.5	\$300.0	\$(6.3)	) \$293.7
3.375% Convertible Senior Notes, due June 2038*	68.3	(1.2)	) 67.1	95.9	(5.7)	) 90.2

\*The carrying amount of the equity component was \$30.1 million at both December 31, 2012 and 2011.

The unamortized discount of the 10.5% Senior Notes is being amortized to interest expense over the life of the debt instrument. The unamortized discount of the 3.375% Convertible Senior Notes is being amortized to interest expense over their expected life which ends June 1, 2013.

	Year Ended December 31, 2012				2011			
	Coupon Interest (in millions)	Discount Amortization	Total Interest	Effective Rate	Coupon Interest (in millions)	Discount Amortization	Total Interest	Effective Rate
10.5% Senior Notes, due October 2017	\$31.5	\$0.8	\$32.3	11.00 %	\$31.4	\$0.8	\$32.2	11.00 %
3.375% Convertible Senior Notes, due June 2038	2.7	3.2	5.9	7.93	3.2	3.7	6.9	7.93

	Year Ended December 31, 2010			
	Coupon Interest (in millions)	Discount Amortization	Total Interest	Effective Rate
10.5% Senior Notes, due October 2017	\$31.4	\$0.7	\$32.1	11.00 %
3.375% Convertible Senior Notes, due June 2038	3.3	3.4	6.7	7.93



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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Senior Secured Credit Agreement

At December 31, 2011, the Company previously had a \$592.9 million credit agreement, consisting of a \$452.9 million term loan facility and a \$140.0 million revolving credit facility. In addition to its scheduled payments, in January 2012, the Company used the net proceeds from asset sales to retire \$17.6 million of the outstanding balance of the Company's term loan facility as required under the prior credit agreement. In addition, on April 3, 2012, the Company repaid in full all outstanding indebtedness under the prior secured credit facilities, and the liens securing such obligations were terminated. There were no termination penalties incurred by the Company in connection with the termination of the prior secured credit facility.

On April 3, 2012, the Company entered into a new credit agreement (the "Credit Agreement"), which governs its new senior secured revolving credit facility (the "Credit Facility"), which provides for a \$75.0 million senior secured revolving credit facility, with a \$25.0 million sublimit for the issuance of letters of credit. As of December 31, 2012, no amounts were outstanding and \$1.0 million in letters of credit had been issued under the Credit Facility, therefore the remaining availability under this facility was \$74.0 million.

The Company may prepay borrowings under the Credit Facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements. The Credit Agreement requires mandatory prepayments of amounts outstanding thereunder with the net proceeds of certain asset sales, casualty events, preferred stock issuances and debt issuances, but these mandatory prepayments do not require any reduction of the lenders' commitments under the Credit Agreement. All borrowings under the Credit Facility mature on April 3, 2017.

Borrowings under the Credit Facility bear interest, at the Company's option, at either (i) the Alternate Base Rate ("ABR") (the highest of the administrative agent's corporate base rate of interest, the federal funds rate plus 0.5%, or the one-month Eurodollar rate (as defined in the Credit Agreement) plus 1%), plus an applicable margin that ranges between 3.0% and 4.5%, depending on the Company's leverage ratio, or (ii) the Eurodollar rate plus an applicable margin that ranges between 4.0% and 5.5%, depending on the Company's leverage ratio. The Company will pay a per annum fee on all letters of credit issued under the Credit Facility, which fee will equal the applicable margin for loans accruing interest based on the Eurodollar rate, and the Company will pay a commitment fee of 0.75% per annum on the unused availability under the Credit Facility.

In addition, during any period of time that outstanding letters of credit under the Credit Facility exceed \$10 million or there are any revolving borrowings outstanding under the Credit Facility, the Company will have to maintain compliance with a maximum secured leverage ratio (as defined in the Credit Agreement, being generally computed as the ratio of secured indebtedness to consolidated cash flow). The maximum secured leverage ratio is 3.50 to 1.00.

The Company's obligations under the Credit Agreement are guaranteed by substantially all of the Company's current domestic subsidiaries (collectively, the "Guarantors"), and the obligations of the Company and the Guarantors are secured by liens on substantially all of the vessels owned by the Company and the Guarantors, together with certain accounts receivable, equity of subsidiaries, equipment and other assets.

7.125% Senior Secured Notes due 2017

On April 3, 2012 the Company completed the issuance and sale of \$300.0 million aggregate principal amount of senior secured notes at a coupon rate of 7.125% ("7.125% Senior Secured Notes") with maturity in April 2017. These notes were sold at par and the Company received net proceeds from the offering of the notes of \$293.0 million after deducting the initial purchasers' discounts and offering expenses. Interest on the 7.125% Senior Secured Notes is payable in cash semi-annually in arrears on April 1 and October 1 of each year.

The 7.125% Senior Secured Notes are guaranteed by each of the Guarantors that guarantee the Company's obligations under its Credit Agreement. The notes are secured by liens on all collateral that secures the Company's obligations under its Credit Agreement, subject to limited exceptions. The liens securing the notes share on an equal and ratable first priority basis with liens securing the Company's Credit Agreement. Under the intercreditor agreement the collateral agent for the lenders under the Company's Credit Agreement is generally entitled to sole control of all decisions and actions.

10.25% Senior Notes due 2019

On April 3, 2012 the Company completed the issuance and sale of \$200.0 million aggregate principal amount of senior notes at a coupon rate of 10.25% ("10.25% Senior Notes") with maturity in April 2019. These notes were sold at par and the Company received net proceeds from the offering of the notes of \$195.4 million after deducting the initial purchasers' discounts and offering expenses. Interest on the 10.25% Senior Notes is payable in cash semi-annually in arrears on April 1 and October 1 of each year.

The 10.25% Senior Notes are guaranteed by each of the Guarantors that guarantee the Company's obligations under the Company's Credit Agreement.

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

10.5% Senior Notes due 2017 (Formerly Secured prior to April 3, 2012)

The interest on the 10.5% Senior Notes due 2017 ("10.5% Senior Notes") is payable in cash semi-annually in arrears on April 15 and October 15 of each year to holders of record at the close of business on April 1 or October 1.

The indenture governing the 10.5% Senior Notes provides that all the liens securing the notes may be released if the Company's total amount of secured indebtedness, other than the 10.5% Senior Notes, does not exceed the lesser of \$375.0 million and 15.0% of the Company's consolidated tangible assets. The Company refers to such a release as a "collateral suspension." When a collateral suspension is in effect, the 10.5% Senior Notes due 2017 become unsecured. Following the closing of the 2012 debt issuances and the use of proceeds thereof to repay in full the prior secured credit facility, the liens securing the 10.5% Senior Notes were released on April 3, 2012 and a collateral suspension is currently in effect. The indenture governing the 10.5% Senior Notes also provides that if, after any such collateral suspension, the aggregate principal amount of the Company's total secured indebtedness, other than the 10.5% Senior Notes due 2017, were to exceed the greater of \$375.0 million and 15.0% of the Company's consolidated tangible assets, as defined in such indenture, then the collateral obligations of the Company and guarantors thereunder will be reinstated and must be complied with within 30 days of such event.

The 10.5% Senior Notes are guaranteed by each of the Guarantors that guarantee the Company's obligations under its Credit Agreement.

3.375% Convertible Senior Notes due 2038

The interest on the 3.375% Convertible Senior Notes due 2038 ("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. The Company 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 the Company's 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 approximately \$50.08 per share. Upon conversion of a note, a holder will receive, at the Company's election, shares of Common Stock, cash or a combination of cash and shares of Common Stock. At December 31, 2012, the number of conversion shares potentially issuable in relation to the 3.375% Convertible Senior Notes was 1.4 million. The Company may redeem the notes at its option beginning June 6, 2013, and holders of the notes will have the right to require the Company to repurchase the notes on June 1, 2013 and certain dates thereafter or on the occurrence of a fundamental change.

The Company determined that upon maturity or redemption, it has the intent and ability to settle the principal amount of its 3.375% Convertible Senior Notes in cash, and any additional conversion consideration spread (the excess of conversion value over face value) in shares of the Company's Common Stock.

In May 2012, the Company repurchased a portion of the 3.375% Convertible Senior Notes and in accordance with ASC 470-20 Debt - Debt with Conversion and Other Options, 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.

Other Indenture Provisions

The Credit Agreement as well as the indentures governing the 7.125% Senior Secured Notes, 10.25% Senior Notes, 10.5% Senior Notes and 3.375% Convertible Senior Notes contain customary events of default. In addition, the Credit Agreement as well as the indentures governing the 7.125% Senior Secured Notes, 10.25% Senior Notes, 10.5% Senior Notes and 3.375% Convertible Senior Notes also contain a provision under which an event of default by the Company or by any restricted subsidiary on any other indebtedness exceeding \$25.0 million would be considered an event of

default under the Credit Agreement and indentures 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.

The Credit Agreement as well as the indentures governing the 7.125% Senior Secured Notes, 10.25% Senior Notes and 10.5% Senior Notes contain covenants that, among other things, limit the Company's ability and the ability of its restricted subsidiaries to:

- incur additional indebtedness or issue certain preferred stock;
- pay dividends or make other distributions;
- make other restricted payments or investments;

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

sell assets;  
create liens;  
enter into agreements that restrict dividends and other payments by restricted subsidiaries;  
engage in transactions with affiliates; and  
consolidate, merge or transfer all or substantially all of its assets.

Loss on Extinguishment of Debt

During the twelve months ended December 31, 2012, the Company incurred the following charges which are included in Loss on Extinguishment of Debt in the Consolidated Statements of Operations:

In April 2012 and in connection with the termination of the prior secured credit facility, the Company recognized a pretax charge of \$1.4 million, \$0.9 million, net of tax, for the write off of unamortized issuance costs related to the term loan;

In April 2012, the Company recognized a pretax charge of \$6.4 million, \$4.2 million net of tax, related to the Company's debt refinancing; and

In May 2012, the Company repurchased \$27.6 million aggregate principal amount of the 3.375% Convertible Senior Notes, resulting in a loss of \$1.3 million, or \$0.9 million, net of tax.

11. Derivative Instruments

Warrants

The Company was issued warrants to purchase up to 5.0 million additional shares of Discovery Offshore stock at a strike price of 11.50 Norwegian Kroner ("NOK") per share which is exercisable in the event that the Discovery Offshore stock price reaches an average equal to or higher than 23.00 NOK per share for 30 consecutive trading days. As of December 31, 2012, Discovery Offshore's stock price was 13.00 NOK per share. The warrants are being accounted for as a derivative instrument as the underlying security is readily convertible to cash. Subsequent changes in the fair value of the warrants are recognized to other income (expense). The fair value of the Discovery Offshore warrants was determined using a Monte Carlo simulation (See Note 12).

Interest Rate Contracts

The Company has historically used derivative instruments to manage its exposure to interest rate risk, including interest rate swap agreements to effectively fix the interest rate on variable rate debt and interest rate collars to limit the interest rate range on variable rate debt. These are recognized in the statement of financial position at fair value, with changes in fair value determined on whether they have been designated and qualify as part of a hedging relationship and further, on the type of hedging relationship. For those derivative instruments that are designated and qualify as hedging instruments, a company must designate the hedging instrument based upon the exposure being hedged as a fair value hedge, cash flow hedge or a hedge of a net investment in a foreign operation. These hedge transactions have historically been accounted for as cash flow hedges such that the effective portion of the gain or loss on the derivative instrument is reported as a component of other comprehensive income and reclassified into earnings in the same line item associated with the forecasted transaction and in the period or periods during which the hedged transaction affects earnings. The effective portion of the interest rate swaps and collar hedging the exposure to variability in expected future cash flows due to changes in interest rates is reclassified into interest expense. The remaining gain or loss on the derivative instrument in excess of the cumulative change in the present value of future cash flows of the hedged item, if any, or hedged components excluded from the assessment of effectiveness, is recognized in interest expense. Currently, the Company has no derivative instruments outstanding related to managing interest rate risk. However, in July 2007, the Company entered into a zero cost LIBOR collar on \$300.0 million of term loan principal, which was settled on October 1, 2010 per the agreement with a cash payment of \$3.4 million, with a ceiling of 5.75% and a floor of 4.99%. The counterparty was obligated to pay the Company in any quarter that actual LIBOR reset above 5.75% and the Company paid the counterparty in any quarter that actual LIBOR reset 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 2009 Credit Amendment.

As a result of the inclusion of a LIBOR floor in the previous credit agreement, the Company determined, as of July 27, 2009 and on an ongoing basis, that the interest rate collar (which was settled on October 1, 2010) would not 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, the Company discontinued cash flow hedge accounting for the interest rate collar as of July 27, 2009. Because cash flow hedge accounting was not applied to this instrument, changes in fair value related to the interest rate collar subsequent to July 27, 2009 were recorded in earnings.

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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table provides the fair values of the Company's derivatives:

Balance Sheet Classification	Fair Value	
	December 31, 2012	December 31, 2011
	(in thousands)	
Derivatives:		
Warrants	\$3,964	\$1,758
Other Assets, Net	\$3,964	\$1,758

The following table provides the effect of the Company's derivatives on the Consolidated Statements of Operations:

Derivatives	I.	Year Ended December 31,			III.	IV.	2011	2010
		2012	2011	2010				
		(in thousands)				(in thousands)		
Interest rate contracts(a)	Interest Expense	\$—	\$—	\$(8,881 )	Interest Expense	\$—	\$—	\$(264 )
Warrants	N/A	N/A	N/A	N/A	Other Income (Expense)	\$2,206	\$(3,288 )	\$—

(a) These interest rate contracts were designated as cash flow hedges through July 27, 2009.

- I. Classification of Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) into Income (Loss) (Effective Portion)
- II. Amount of Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) into Income (Loss) (Effective Portion)
- III. Classification of Gain (Loss) Recognized in Income (Loss) on Derivative
- IV. Amount of Gain (Loss) Recognized in Income (Loss) on Derivative

A summary of the changes in Accumulated Other Comprehensive Loss (in thousands):

Cumulative unrealized loss, net of tax of \$3,108, as of December 31, 2009	\$(5,773 )
Reclassification of losses into net income, net of tax of \$3,108	5,773
Cumulative unrealized loss, net of tax, as of December 31, 2010	\$—

## 12. Fair Value Measurements

Fair value measurements are generally based upon observable and unobservable inputs. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect the Company's view of market assumptions in the absence of observable market information. The Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The Company uses the fair value hierarchy included in Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 820-10, Fair Value Measurements and Disclosure ("ASC 820-10"), which is intended to increase consistency and comparability in fair value measurements and related disclosures. The fair value hierarchy consists of the following three levels:

Level 1 — Inputs are quoted prices in active markets for identical assets or liabilities.

Level 2 — Inputs are quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable and market-corroborated inputs which are derived principally from or corroborated by observable market data.

Level 3 — Inputs are derived from valuation techniques in which one or more significant inputs or value drivers are unobservable.

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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

As of December 31, 2012 the fair value of the warrants issued by Discovery Offshore was \$4.0 million. The fair value of the warrants was determined using a Monte Carlo simulation based on the following assumptions:

	December 31,			
	2012	2011		
Strike Price (NOK)	11.50	11.50		
Target Price (NOK)	23.00	23.00		
Stock Value (NOK)	13.00	8.50		
Expected Volatility (%)	50.0	% 50.0		%
Risk-Free Interest Rate (%)	1.44	% 0.60		%
Expected Life of Warrants (5.0 years at inception)	3.1	4.1		
Number of Warrants	5,000,000	5,000,000		

The Company used the historical volatility of companies similar to that of Discovery Offshore to estimate volatility. The risk-free interest rate assumption was based on observed interest rates consistent with the approximate life of the warrants. The stock price represents the closing stock price of Discovery Offshore stock at December 31, 2012 and 2011, respectively. The strike price, target price, expected life and number of warrants are all contractual based on the terms of the warrant agreement.

The following table represents the Company's derivative asset measured at fair value on a recurring basis as of December 31, 2012 and 2011, respectively:

	Total Fair Value Measurement	Quoted Prices in Active Markets for Identical Asset or Liability (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(in thousands)			
Warrants - as of December 31, 2012	\$3,964	\$—	\$3,964	\$—
Warrants - as of December 31, 2011	\$1,758	\$—	\$1,758	\$—

The following table represents the Company's assets measured at fair value on a non-recurring basis for which an impairment measurement was made as of December 31, 2012:

	Total Fair Value Measurement	Quoted Prices in Active Markets for Identical Asset or Liability (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Gain (Loss)
	(in thousands)				
Property and Equipment, Net (1)	\$1,500	\$—	\$—	\$1,500	\$(42,916)
Property and Equipment, Net (2)	\$9,340	\$—	\$7,840	\$1,500	\$(60,693)

(1) This represents a non-recurring fair value measurement made at June 30, 2012 for Hercules 185.

(2) This represents a non-recurring fair value measurement made at September 30, 2012 for Hercules 252 and Hercules 258.

In April 2012, during the return mobilization from the U.S. Gulf of Mexico to Angola, Hercules 185 experienced extensive damage to various portions of the rig's legs (See Note 17). The Company believed it was unfeasible to repair the damage and return the rig to service and recorded an impairment charge of \$42.9 million (\$27.9 million, net of tax) which is included in Asset Impairment on the Consolidated Statements of Operations for the year ended December 31, 2012 to write the rig down to salvage value.

Long-lived assets held for sale at September 30, 2012 were written down to their fair value less estimated cost to sell, resulting in an impairment charge of approximately \$25.5 million (\$16.6 million, net of tax), which is included in Asset

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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Impairment on the Consolidated Statements of Operations for the year ended December 31, 2012, related to Hercules 252. The sale of Hercules 252 was completed in October 2012 (See Note 6).

During September 2012, the Company made the decision to cold stack Hercules 258 effective October 1, 2012 and removed it from its marketable assets into its non-marketable assets as the Company does not reasonably expect to market this rig in the foreseeable future. This decision resulted in an impairment charge of approximately \$35.2 million (\$35.2 million, net of tax), which is included in Asset Impairment on the Consolidated Statements of Operations for the year ended December 31, 2012, to write the rig down to salvage value based on a third party estimate. The financial information for Hercules 258 has been reported as part of the International Offshore segment. The following table represents the Company's assets measured at fair value on a non-recurring basis for which an impairment measurement was made as of December 31, 2010:

	Total Fair Value Measurement December 31, 2010 (in thousands)	Quoted Prices in Active Markets for Identical Asset or Liability (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Gain (Loss)
Property and Equipment, Net	\$27,848	\$ —	\$ —	\$27,848	\$(125,136 )

During the fourth quarter 2010, the Company considered the prolonged downturn in the drilling industry as an indicator of impairment and assessed its segments for impairment as of December 31, 2010. When analyzing its Domestic Offshore, International Offshore and Delta Towing segments for impairment, the Company determined five of its domestic jackup rigs, one of its international jackup rigs and several of its Delta Towing assets that had previously been considered marketable, would not be marketed in the foreseeable future and were included in the impairment analysis of non-marketable assets. This determination was based on the Company's estimate of reactivation costs associated with these assets which, based on current and forecasted near-term dayrates and utilization levels, were economically prohibitive, and the sustained lack of visibility in the issuance of offshore drilling permits in the U.S. Gulf of Mexico at that time. Based on an undiscounted cash flow analysis, it was determined that the non-marketable assets were impaired. The Company estimated the value of the discounted cash flows for each segment's non-marketable assets, which included management's estimate of sales proceeds less costs to sell, and recorded an impairment charge of \$125.1 million (\$81.3 million, net of tax) of which \$2.4 million (\$1.5 million, net of tax) related to the discontinued operations of its Delta Towing segment and is included in Loss from Discontinued Operations, Net of Taxes in the Consolidated Statement of Operations for the year ended December 31, 2010. The Company analyzed its other segments and its marketable assets for impairment as of December 31, 2010 and noted that each segment had adequate undiscounted cash flows to recover its property and equipment carrying values.

The carrying value and fair value of the Company's equity investment in Discovery Offshore was \$38.2 million and \$49.1 million at December 31, 2012, respectively, and \$34.7 million and \$26.1 million at December 31, 2011, respectively. The fair value at December 31, 2012 and 2011 was calculated using the closing price of Discovery Offshore shares at each date respectively (level one input), converted to U.S. dollars using the exchange rate at each respective date.

**Fair Value of Financial Instruments**

The carrying amounts of the Company's financial instruments, which include cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities, approximate fair values because of the short-term nature of the instruments.

The fair value of the Company's 3.375% Convertible Senior Notes, 10.25% Senior Notes, 10.5% Senior Notes, 7.125% Senior Secured Notes and former term loan facility is estimated based on quoted prices in active markets. The fair value of the Company's 7.375% Senior Notes is estimated based on discounted cash flows using inputs from quoted prices in active markets

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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

for similar debt instruments. The inputs used to determine fair value are considered level two inputs. The following table provides the carrying value and fair value of the Company's long-term debt instruments:

	December 31, 2012		December 31, 2011	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in millions)			
Term Loan Facility (terminated April 2012)	n/a	n/a	\$452.9	\$442.0
7.125% Senior Secured Notes, due April 2017	\$300.0	\$317.1	n/a	n/a
10.5% Senior Notes, due October 2017	294.5	326.6	293.7	291.2
10.25% Senior Notes, due April 2019	200.0	219.6	n/a	n/a
3.375% Convertible Senior Notes, due June 2038	67.1	68.5	90.2	84.7
7.375% Senior Notes, due April 2018	3.5	3.3	3.5	2.8

## 13. Supplemental Cash Flow Information

	Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
Cash paid, net during the period for:			
Interest, net of capitalized interest	\$64,332	\$68,672	\$76,993
Income taxes	10,220	7,152	22,092

During 2012, the Company capitalized interest of \$3.6 million. The Company did not capitalize interest in 2011 and 2010.

Non-Cash Investing activities in 2011 include the value of the Company's common stock issued in connection with the Seahawk Transaction of \$125.3 million (See Note 5).

## 14. Concentration of Credit Risk

The Company maintains its cash in bank deposit accounts at high credit quality financial institutions or in highly rated money market funds as permitted by its Credit Agreement. The balances, at many times, exceed federally insured limits.

The Company provides services to a diversified group of customers in the oil and natural gas exploration and production industry. Credit is extended based on an evaluation of each customer's financial condition. The Company maintains an allowance for doubtful accounts receivable based on expected collectability and establishes a reserve when payment is unlikely to occur.

## 15. Income Taxes

Income (loss) before income taxes consisted of the following:

	Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
United States	\$(130,292 )	\$(186,154 )	\$(314,293 )
Foreign	(19,717 )	84,293	94,260
Total	\$(150,009 )	\$(101,861 )	\$(220,033 )

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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The income tax (benefit) provision consisted of the following:

	Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
Current-United States	\$184	\$—	\$—
Current-foreign	14,861	16,153	8,752
Current-state	(4,814	) 314	76
Current income tax provision	10,231	16,467	8,828
Deferred-United States	(33,909	) (50,535	) (100,569
Deferred-foreign	(708	) 304	3,748
Deferred-state	1,381	(1,577	) 53
Deferred income tax benefit	(33,236	) (51,808	) (96,768
Total income tax benefit	\$ (23,005	) \$ (35,341	) \$ (87,940

The components of and changes in the net deferred taxes were as follows:

	December 31,	
	2012	2011
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforward (Federal, State & Foreign)	\$155,895	\$160,272
Credit carryforwards	14,895	14,711
Accrued expenses	19,853	15,767
Unearned income	2,433	5,135
Intangibles	6,167	7,199
Stock-Based Compensation	5,952	7,272
Deferred tax assets	205,195	210,356
Deferred tax liabilities:		
Fixed assets	(226,476	) (258,762
Convertible Notes	(6,496	) (8,199
Deferred expenses	(5,130	) (5,202
Other	(2,688	) (6,079
Deferred tax liabilities	(240,790	) (278,242
Net deferred tax liabilities	\$ (35,595	) \$ (67,886

A reconciliation of statutory and effective income tax rates is as shown below:

	Year Ended December 31,			
	2012	2011	2010	
Statutory rate	35.0	% 35.0	% 35.0	%
Effect of:				
State income taxes	1.2	1.4	—	
Taxes on foreign earnings at greater than the U.S. statutory rate	(18.3	) 0.4	7.8	
Uncertain Tax Positions	(0.1	) (0.6	) 2.2	
Deemed Repatriation of foreign earnings	—	—	(3.7	)
Other	(2.5	) (1.5	) (1.3	)
Effective rate	15.3	% 34.7	% 40.0	%



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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The amount of consolidated U.S. net operating losses (“NOLs”) available as of December 31, 2012 is approximately \$446.9 million. This differs from the NOL reported in the Company's financial statements by \$4.0 million which represents the unrealized tax benefits associated with equity compensation and uncertain tax position in accordance with FASB ASC 718, Stock Compensation and FASB ASC 740, Income Taxes. These NOLs will expire in the years 2024 through 2031. In addition, the Company has \$14.9 million of non-expiring alternative minimum tax credits. The Company has not recorded deferred income taxes on the remaining undistributed earnings of its foreign subsidiaries because of management’s intent to permanently reinvest such earnings. At December 31, 2012, the aggregate amount of undistributed earnings of the foreign subsidiaries was \$72.7 million. Upon distribution of these earnings in the form of dividends or otherwise, the Company may be subject to U.S. income taxes and foreign withholding taxes. It is not practical, however, to estimate the amount of taxes that may be payable on the remittance of these earnings.

In accordance with FASB ASC 740, the Company recognizes interest and penalties related to uncertain tax positions in income tax expense. The Company recorded interest and penalties of \$0.2 million, \$0.2 million and \$0.4 million through the Income Tax Benefit line of the Consolidated Statement of Operations for the years ended December 31, 2012, 2011 and 2010, respectively.

The Company, directly or through its subsidiaries, files income tax returns in the United States, and multiple state and foreign jurisdictions. The Company’s tax returns for 2006 through 2011 remain open for examination by the taxing authorities in the respective jurisdictions where those returns were filed. Although, the Company believes that its estimates are reasonable, the final outcome in the event that the Company is subjected to an audit could be different from that which is reflected in its historical income tax provision and accruals. Such differences could have a material effect on the Company’s income tax provision and net income in the period in which such determination is made. In addition, certain tax returns filed by TODCO and its subsidiaries are open for years prior to 2004, however, TODCO tax obligations from periods prior to its initial public offering in 2004 are indemnified by Transocean, the former owner of TODCO, under the tax sharing agreement, except for the Trinidad and Tobago jurisdiction. The Company’s Trinidadian and Tobago tax returns are open for examination for the years 2006 through 2011.

Effective April 27, 2011 the Company completed the Seahawk Transaction. The Company’s financial statements have been prepared assuming that this transaction should be characterized as a purchase of assets for income tax purposes. Seahawk is in a Chapter 11 proceeding in the U.S. Bankruptcy Court. Subsequent to December 31, 2012, at the direction of the Court, Seahawk made certain distributions to its equity holders. These distributions, taken together with other aspects of the acquisition, will change the tax treatment and will cause the Seahawk Transaction to be characterized as a reorganization pursuant to IRC §368(a)(1)(G). Therefore, for tax purposes the Company will record a carryover basis in the Seahawk assets and other tax attributes. Because of the ownership change certain of these carryovers may be subject to specific, and in some cases an annual, limitation on their utilization. In these instances, the Company will recognize valuation allowances as appropriate. These carryover attributes include net operating losses of \$187 million, tax credits of \$17 million, and tax basis in assets of \$70 million. Based on the Company's current tax position, these will produce additional deferred tax assets of approximately \$35 million (gross additional deferred tax assets of \$56 million offset by valuation allowances of \$21 million). These tax attributes will be recorded in the Company's financial statements in the first quarter of 2013 based on the effective date of the equity distribution. There can be no assurance that these deferred tax assets will be realized.

The following table presents the reconciliation of the total amounts of unrecognized tax benefits that, if recognized, would impact the effective income tax rate:

	Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
Balance, beginning of period	\$5,533	\$4,109	13,529
Gross increases — tax positions in prior periods	—	1,424	—

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Gross decreases — tax positions in prior periods	—	—	(1,499	)
Settlements	—	—	(7,921	)
Balance, end of period	\$5,533	\$5,533	\$4,109	

From time to time, the Company's tax returns are subject to review and examination by various tax authorities within the jurisdictions in which the Company operates or has operated. The Company is currently contesting tax assessments in Venezuela, and may contest future assessments where the Company believes the assessments are meritless.

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

In January 2008, SENIAT, the national Venezuelan tax authority, commenced an audit for the 2003 calendar year, which was completed in the fourth quarter of 2008. The Company has not yet received any proposed adjustments from SENIAT for that year.

In March 2007, a subsidiary of the Company received an assessment from the Mexican tax authorities related to its operations for the 2004 tax year. This assessment contested the Company's right to certain deductions and also claimed it did not remit withholding tax due on certain of these deductions. In 2008, the Mexican tax authorities commenced an audit for the 2005 tax year. During 2010, the Company effectively reached a compromise settlement of all issues for 2004 through 2007. The Company paid \$11.6 million and reversed (i) previously provided reserves and (ii) an associated tax benefit in the year ended December 31, 2010 which totaled \$5.8 million.

16. Segments

The Company reports its business activities in five business segments: (1) Domestic Offshore, (2) International Offshore, (3) Inland, (4) Domestic Liftboats and (5) International Liftboats. The financial information of the Company's discontinued operations is not included in the results of operations presented for the Company's reporting segments (See Note 6). The Company eliminates inter-segment revenue and expenses, if any.

In March 2012, the Company acquired an offshore jackup drilling rig, Hercules 266, for \$40.0 million. The Company has entered into a three-year drilling contract with Saudi Aramco for the use of this rig with Saudi Aramco having an option to extend the term for an additional one-year period. This rig is currently undergoing upgrades and other contract specific refurbishments and the Company expects the rig to commence work under the contract in the second quarter of 2013.

During April 2012, the Kingfish, a 230 class liftboat, began its mobilization from the U.S. Gulf of Mexico to the Middle East, where it underwent upgrades prior to becoming reactivated. The vessel commenced work in November 2012.

During November 2012, the decision was made to reactivate one of our previously cold stacked rigs, Hercules 209. Hercules 209 is currently in the shipyard undergoing repairs and upgrades for reactivation and is expected to be available for work in the second quarter of 2013.

The following describes the Company's reporting segments as of December 31, 2012:

Domestic Offshore — includes 29 jackup rigs in the U.S. Gulf of Mexico that can drill in maximum water depths ranging from 85 to 350 feet. Nineteen of the jackup rigs are either under contract or available for contracts and ten are cold stacked.

International Offshore — includes eight jackup rigs outside of the U.S. Gulf of Mexico. We have three jackup rigs contracted offshore in Saudi Arabia, one jackup rig contracted offshore in Myanmar and one jackup rig contracted offshore in Cameroon. In addition, we have one jackup rig warm stacked and one jackup rig cold stacked in Bahrain as well as one jackup rig cold stacked in Malaysia. In addition to owning and operating our own rigs, we have the Construction Management Agreement and the Services Agreement with Discovery Offshore with respect to each of its two rigs (See Note 2).

Inland — includes a fleet of four conventional and ten 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 under contract or available and eleven are cold stacked.

Domestic Liftboats — includes 39 liftboats in the U.S. Gulf of Mexico. Thirty-two are operating or available for contracts and seven are cold stacked.

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

The Company's jackup rigs and submersible rigs are used primarily for exploration and development drilling in shallow waters. The Company's 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.

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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Information regarding the Company's reportable segments is as follows:

	Year Ended December 31, 2012			Year Ended December 31, 2011		
	Revenue	Income (Loss) from Operations (in thousands)	Depreciation and Amortization	Revenue	Income (Loss) from Operations (in thousands)	Depreciation and Amortization
Domestic Offshore (a)	\$355,762	\$10,518	\$72,938	\$217,450	\$(46,103)	\$68,146
International Offshore (b)	135,047	(59,205)	45,577	237,047	57,842	52,278
Inland	28,015	(11,654)	12,842	28,180	(10,770)	14,589
Domestic Liftboats	63,832	5,578	15,524	56,575	(3,325)	15,329
International Liftboats	127,136	38,611	16,896	116,106	30,909	19,624
	\$709,792	\$(16,152)	\$163,777	\$655,358	\$28,553	\$169,966
Corporate	—	(47,425)	2,649	—	(47,302)	2,605
Total Company	\$709,792	\$(63,577)	\$166,426	\$655,358	\$(18,749)	\$172,571

(a) 2012 Income (Loss) from Operations for the Company's Domestic Offshore segment includes an asset impairment charge of \$25.5 million (See Note 12).

(b) 2012 Income (Loss) from Operations for the Company's International Offshore segment includes an asset impairment charge of \$82.7 million (See Note 12). In addition, Income (Loss) from Operations for the Company's International Offshore segment includes a gain on the sale of Platform Rig 3 of \$18.4 million and a gain on Hercules 185 insurance settlement of \$27.3 million (See Notes 6 and 17).

	Year Ended December 31, 2010		
	Revenue	Income (Loss) from Operations (in thousands)	Depreciation and Amortization
Domestic Offshore (a)	\$124,063	\$(182,394)	\$68,335
International Offshore (b)	291,516	56,878	58,275
Inland	21,922	(27,876)	23,516
Domestic Liftboats	70,710	12,089	14,698
International Liftboats	116,616	37,211	17,711
	\$624,827	\$(104,092)	\$182,535
Corporate	—	(39,335)	3,177
Total Company	\$624,827	\$(143,427)	\$185,712

(a) 2010 Income (Loss) from Operations includes an impairment of property and equipment charge of \$84.7 million.

(b) 2010 Income (Loss) from Operations includes an impairment of property and equipment charge of \$38.0 million.

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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Total Assets	
	December 31, 2012	December 31, 2011
	(in thousands)	
Domestic Offshore	\$980,973	\$890,339
International Offshore	649,565	705,831
Inland	107,349	119,356
Domestic Liftboats	74,824	82,234
International Liftboats	147,823	154,974
Corporate	56,096	53,970
Total Company	\$2,016,630	\$2,006,704

	Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
Capital Expenditures and Deferred Drydocking Expenditures:			
Domestic Offshore	\$42,016	\$27,088	\$11,133
International Offshore (a)	114,235	4,324	6,469
Inland	1,560	213	758
Domestic Liftboats	9,692	11,866	9,987
International Liftboats	8,489	11,217	7,470
Delta Towing	—	301	927
Corporate	2,613	213	314
Total Company	\$178,605	\$55,222	\$37,058

(a) 2012 Includes the purchase of Hercules 266 as well as related upgrades, contract specific refurbishments and mobilization costs.

A substantial portion of the Company's assets are mobile. Asset locations at the end of the period are not necessarily indicative of the geographic distribution of the revenue generated by such assets during the periods. The following tables present revenue and long-lived assets by country based on the location of the service provided:

	Year Ended December 31,		
	2012	2011	2010
	(in thousands)		
Operating Revenue:			
United States	\$447,609	\$302,206	\$216,695
Nigeria	105,176	98,256	97,163
Saudi Arabia	55,911	93,920	103,712
India	56	61,925	130,533
Other (a)	101,040	99,051	76,724
Total	\$709,792	\$655,358	\$624,827

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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	As of December 31,	
	2012	2011
	(in thousands)	
Long-Lived Assets:		
United States	\$883,308	\$1,034,511
Nigeria	83,979	99,812
Saudi Arabia	261,433	253,708
India	—	39,446
Other (a)	309,303	229,225
Total	\$1,538,023	\$1,656,702

(a) Other represents countries in which the Company operates that individually had operating revenue or long-lived assets representing less than 10% of total operating revenue or total long-lived assets.

Sales to Major Customers

The Company's customers primarily include major integrated energy companies, independent oil and natural gas operators and national oil companies. Sales to customers exceeding 10 percent or more of the Company's total revenue in any of the past three years are as follows:

	Year Ended December 31,			
	2012	2011	2010	
Chevron Corporation (a)	17	% 25	% 17	%
Saudi Aramco (b)	6	13	14	
Oil and Natural Gas Corporation Limited (b)	—	9	20	

(a) Revenue included in the Company's Domestic Offshore, International Offshore, Domestic Liftboats and International Liftboats segments.

(b) Revenue included in the Company's International Offshore segment.

17. Commitments and ContingenciesOperating Leases

The Company has non-cancellable operating lease commitments that expire at various dates through 2017. As of December 31, 2012, future minimum lease payments related to non-cancellable operating leases were as follows (in thousands):

Years Ended December 31,	
2013	\$3,945
2014	3,278
2015	2,525
2016	2,126
2017	2,162
Thereafter	—
Total	\$14,036

Rental expense for all operating leases was \$13.8 million, \$12.9 million and \$13.2 million for the years ended December 31, 2012, 2011 and 2010, respectively.

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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Legal Proceedings

The Company is involved in various claims and lawsuits in the normal course of business. As of December 31, 2012, management did not believe any accruals were necessary in accordance with FASB ASC 450-20, Contingencies — Loss Contingencies.

Termination of Foreign Corrupt Practices Act Investigations

On April 4, 2011, the Company received a subpoena issued by the Securities and Exchange Commission (“SEC”) requesting the delivery of certain documents to the SEC in connection with its investigation into possible violations of the securities laws, including possible violations of the Foreign Corrupt Practices Act (“FCPA”) in certain international jurisdictions where the Company conducts operations. The Company was also notified by the Department of Justice (“DOJ”) on April 5, 2011, that certain of the Company’s activities were under review by the DOJ.

On April 24, 2012, the Company received a letter from the DOJ notifying the Company that the DOJ had closed its inquiry into the Company regarding possible violations of the FCPA and did not intend to pursue enforcement action against the Company or impose any fines or penalties against the Company. Additionally, on August 7, 2012, the Company received a letter from the SEC notifying the Company that the SEC staff had completed its investigation into the Company regarding possible violations of the FCPA and did not intend to pursue enforcement action against the Company or impose any fines or penalties against the Company. As a result of these terminations by the SEC and the DOJ, there are no open FCPA investigations against the Company.

Shareholder Derivative Suits

Say-on-Pay Litigation

In June 2011, two separate shareholder derivative actions were filed purportedly on the Company’s behalf in response to its failure to receive a majority advisory “say-on-pay” vote in favor of the Company’s 2010 executive compensation. On June 8, 2011, the first action was filed in the District Court of Harris County, Texas, and on June 23, 2011, the second action was filed in the United States Court for the District of Delaware. Subsequently, on July 21, 2011, the plaintiff in the Harris County action filed a concurrent action in the United States District Court for the Southern District of Texas. Each action named the Company as a nominal defendant and certain of its officers and directors, as well as the Company’s Compensation Committee’s consultant, as defendants. Plaintiffs allege that the Company’s directors breached their fiduciary duty by approving excessive executive compensation for 2010, that the Compensation Committee consultant aided and abetted that breach of fiduciary duty, that the officer defendants were unjustly enriched by receiving the allegedly excessive compensation, and that the directors violated the federal securities laws by disseminating a materially false and misleading proxy. The plaintiffs seek damages in an unspecified amount on the Company’s behalf from the officer and director defendants, certain corporate governance actions, and an award of their costs and attorney’s fees. The Company and the other defendants have filed motions to dismiss these cases for failure to make demand upon the Company’s board and for failing to state a claim. Those motions are pending. On June 11, 2012, the plaintiff in the Harris County action voluntarily dismissed his action.

The Company does not expect the ultimate outcome of any of these shareholder derivative lawsuits to have a material adverse effect on its consolidated results of operations, financial position or cash flows.

The Company and its subsidiaries are involved in a number of other lawsuits, all of which have arisen in the ordinary course of business. The Company does not believe that ultimate liability, if any, resulting from any such other pending litigation will have a material adverse effect on its business or consolidated financial statements.

The Company cannot predict with certainty the outcome or effect of any of the litigation matters specifically described above or of any other pending litigation. There can be no assurance that the Company’s 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.

Insurance and Indemnity

The Company is self-insured for the deductible portion of its insurance coverage. Management believes adequate accruals have been made on known and estimated exposures up to the deductible portion of the Company’s insurance

coverage. Management believes that claims and liabilities in excess of the amounts accrued are adequately insured. However, the Company's insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect the Company against liability from all potential consequences. In addition, there is no assurance of renewal or the ability to obtain coverage acceptable to the Company.

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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The Company maintains insurance coverage that includes coverage for physical damage, third party liability, workers' compensation and employer's liability, general liability, vessel pollution and other coverages.

In April 2012, the Company completed the annual renewal of all of its key insurance policies. The Company's primary marine package provides for hull and machinery coverage for substantially all of the Company's rigs and liftboats up to a scheduled value of each asset. The total maximum amount of coverage for these assets is \$1.6 billion. The marine package includes protection and indemnity and maritime employer's liability coverage for marine crew personal injury and death and certain operational liabilities, with primary coverage (or self-insured retention for maritime employer's liability coverage) of \$5.0 million per occurrence with excess liability coverage up to \$200.0 million. The marine package policy also includes coverage for personal injury and death of third parties with primary and excess coverage of \$25.0 million per occurrence with additional excess liability coverage up to \$200.0 million, subject to a \$250,000 per-occurrence deductible. The marine package also provides coverage for cargo and charterer's legal liability. The marine package includes limitations for coverage for losses caused in U.S. Gulf of Mexico named windstorms, including an annual aggregate limit of liability of \$75.0 million for property damage and removal of wreck liability coverage. The Company also procured an additional \$75.0 million excess policy for removal of wreck and certain third-party liabilities incurred in U.S. Gulf of Mexico named windstorms. Deductibles for events that are not caused by a U.S. Gulf of Mexico named windstorm are 12.5% of the insured drilling rig values per occurrence, subject to a minimum of \$1.0 million, and \$1.0 million per occurrence for liftboats. The deductible for drilling rigs and liftboats in a U.S. Gulf of Mexico named windstorm event is \$25.0 million. Vessel pollution is covered under a Water Quality Insurance Syndicate policy ("WQIS Policy") providing limits as required by applicable law, including the Oil Pollution Act of 1990. The WQIS Policy covers pollution emanating from the Company's vessels and drilling rigs, with primary limits of \$5.0 million (inclusive of a \$3.0 million per-occurrence deductible) and excess liability coverage up to \$200.0 million.

Control-of-well events generally include an unintended flow from the well that cannot be contained by equipment on site (e.g., a blow-out preventer), by increasing the weight of the drilling fluid, or that does not naturally close itself off through what is typically described as "bridging over". The Company carries a contractor's extra expense policy with \$25.0 million primary liability coverage for well control costs, expenses incurred to redrill wild or lost wells and pollution, with excess liability coverage up to \$200.0 million for pollution liability that is covered in the primary policy. The policies are subject to exclusions, limitations, deductibles, self-insured retention and other conditions. In addition to the marine package, the Company has separate policies providing coverage for onshore foreign and domestic general liability, employer's liability, auto liability and non-owned aircraft liability, with customary deductibles and coverage.

The Company's drilling contracts provide for varying levels of indemnification from its customers and in most cases, may require the Company to indemnify its customers for certain liabilities. Under the Company's drilling contracts, liability with respect to personnel and property is customarily assigned on a "knock-for-knock" basis, which means that the Company and its customers assume liability for their respective personnel and property, regardless of how the loss or damage to the personnel and property may be caused. The Company's customers typically assume responsibility for and agree to indemnify the Company from any loss or liability resulting from pollution or contamination, including clean-up and removal and third-party damages arising from operations under the contract and originating below the surface of the water, including as a result of blow-outs or cratering of the well ("Blowout Liability"). The customer's assumption for Blowout Liability may, in certain circumstances, be limited or could be determined to be unenforceable in the event of the Company's gross negligence, willful misconduct or other egregious conduct. In addition, the Company may not be indemnified for statutory penalties and punitive damages relating to such pollution or contamination events. The Company generally indemnifies the customer for the consequences of spills of industrial waste or other liquids originating solely above the surface of the water and emanating from its rigs or vessels.

In 2012, in connection with the renewal of certain of its insurance policies, the Company entered into an agreement to finance a portion of its annual insurance premiums. Approximately \$30.1 million was financed through this

arrangement with an interest rate of 3.54% and a maturity date of March 2013, of which \$9.1 million was outstanding at December 31, 2012. There was \$5.2 million outstanding in insurance notes payable at December 31, 2011 which was fully paid during 2012. The amount financed, related interest rate and maturity date in connection with the prior year renewal was \$25.8 million at 3.59% which matured in March 2012.

#### Insurance Claims Settlement

In September 2011, the Company was conducting a required annual spud can inspection on Hercules 185 in protected waters offshore Angola. While conducting the inspection, it was determined that the spud can on the starboard leg had detached from the leg. Subsequently, additional leg damage was identified. The rig underwent repairs related to this damage and was mobilized back to Angola. During the return mobilization from the U.S. Gulf of Mexico to Angola, Hercules 185 experienced additional damage to its legs. The Company conducted a survey of the rig's legs above and below the water line and discovered extensive damage to various portions of the rig's legs. In June 2012, the Company determined that it was unfeasible to repair

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## HERCULES OFFSHORE, INC. AND SUBSIDIARIES

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

the damage and return the rig to service and recorded an impairment charge to write the rig down to salvage value (See Note 12). The Company and its insurance underwriters reached a global settlement in September 2012, agreeing that Hercules 185 should be considered a constructive total loss. From this settlement, the Company received total insurance proceeds of \$41.0 million for the rig, including \$7.5 million received in June 2012 for its earlier claim relating to previous leg damage to the rig. These proceeds generated a gain on insurance settlement of \$27.3 million which is included in Operating Expenses on the Consolidated Statements of Operations for the year ended December 31, 2012. As part of the settlement, the Company agreed to transport and attempt to sell the rig, with the Company being entitled to the first \$1.5 million in proceeds from such sale and any sale proceeds in excess of \$1.5 million being split seventy-five percent to the underwriters and twenty-five percent to the Company.

## Sales and Use Tax Audits

Certain of the Company's legal entities are under audit by various taxing authorities for several prior-year periods. These audits are ongoing and the Company is working to resolve all relevant issues. The Company has an accrual of \$12.0 million and \$6.5 million related to these sales and use tax matters, which is included in Accrued Liabilities on the Consolidated Balance Sheets as of December 31, 2012 and 2011, respectively.

## 18. Unaudited Interim Financial Data

Unaudited interim financial information for the years ended December 31, 2012 and 2011 is as follows:

	Quarter Ended			
	March 31	June 30 (a)	September 30 (b)	December 31
	(in thousands, except per share amounts)			
2012				
Revenue	\$ 143,319	\$ 178,951	\$ 184,888	\$ 202,634
Operating Income (Loss)	(28,570)	) (38,569)	) (17,956)	) 21,518
Net Income (Loss)	\$ (38,342)	) \$ (55,071)	) \$ (37,858)	) \$ 4,267
Net Income (Loss) Per Share:				
Basic	\$ (0.28)	) \$ (0.35)	) \$ (0.24)	) \$ 0.03
Diluted	(0.28)	) (0.35)	) (0.24)	) 0.03
	Quarter Ended			
	March 31	June 30	September 30	December 31
	(in thousands, except per share amounts)			
2011				
Revenue	\$ 159,378	\$ 170,201	\$ 162,991	\$ 162,788
Operating Loss	(1,622)	) (3,958)	) (3,033)	) (10,136)
Loss from Continuing Operations	(13,643)	) (14,303)	) (17,044)	) (21,530)
Income (Loss) from Discontinued Operations, Net of Taxes	(576)	) (9,127)	) 52	) 43
Net Loss	\$ (14,219)	) \$ (23,430)	) \$ (16,992)	) \$ (21,487)
Basic and Diluted Loss Per Share:				
Loss from Continuing Operations	\$ (0.12)	) \$ (0.11)	) \$ (0.12)	) \$ (0.16)
Income (Loss) from Discontinued Operations	—	) (0.07)	) —	) —
Net Loss	\$ (0.12)	) \$ (0.18)	) \$ (0.12)	) \$ (0.16)

(a) Includes \$47.5 million in asset impairment charges (See Notes 12 and 17).

(b) Includes \$60.7 million in asset impairment charges, an \$18.4 million gain on the sale of Platform Rig 3 and a \$27.3 million gain on the Hercules 185 insurance settlement (See Notes 6, 12 and 17).



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HERCULES OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

19. Related Parties

The Company engages in transactions in the ordinary course of business with entities with whom certain of our directors or members of management have a relationship. The Company has determined that these transactions were carried out on an arm's-length basis and are not material individually or in the aggregate. All of these transactions were approved in accordance with the Company's Policy on Covered Transactions with Related Persons. The following provides a brief description of these relationships.

The Company's Chairman of the Board of Directors was a Senior Advisor to Lime Rock Partners in 2012, which holds an investment interest in Global Energy Services, which includes the Southwest Oilfield Products division, an oilfield equipment manufacturing company, and which holds an investment interest in Tesco Corporation, an oilfield equipment and services company. The Company's Chairman of the Board of Directors is also a member of the Board of Directors of Independence Contract Drilling, which purchased Louisiana Electric Rig Services, an equipment manufacturing and service company, from Global Energy Services in 2012.

A member of the Company's Board of Directors is a member of the Board of Directors of HCC Insurance Holdings, a specialty insurance group.

A member of the Company's Board of Directors is a member of the Board of Directors of Bristow Group, Inc.

The Company holds a three percent investment in each of Hall-Houston Exploration II, L.P., Hall-Houston Exploration III, L.P. and Hall-Houston Exploration IV, L.P., exploration and production funds.

The Company has an investment in approximately 32% of the total outstanding equity of Discovery Offshore. Two of the Company's officers are on the Board of Directors of Discovery Offshore (See Note 2).

20. Subsequent Events

In February 2013, at the direction of the Court, Seahawk made certain distributions to its equity holders. These distributions, taken together with other aspects of the acquisition, will change the Company's tax treatment and will cause the Seahawk Transaction to be characterized as a reorganization pursuant to IRC §368(a)(1)(G) (See Note 15).

In February 2013, the Company entered into a definitive agreement to acquire the offshore drilling rig Ben Avon from a subsidiary of KCA Deutag. The purchase price was \$55.0 million in cash and the Company expects the acquisition to close in late March 2013. In addition, the Company signed a three-year rig commitment with Cabinda Gulf Oil Company Limited for use of the Ben Avon. The Company expects the rig to commence work in the second quarter of 2013.

In February 2013, the Company entered into a definitive agreement to acquire the liftboat Titan 2, a 280 class vessel, from a subsidiary of KS Energy Ltd. The purchase price was \$42.0 million in cash and the Company expects the acquisition to close in early March 2013. The liftboat is currently located in Limbe, Cameroon. In addition, the Company signed a Letter of Intent for a short term commitment to use the Titan 2 and expects the vessel to commence work shortly after the acquisition closes.

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Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure  
None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our chief executive officer and our chief financial officer, evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Our chief executive officer and chief financial officer evaluated whether our disclosure controls and procedures as of the end of the period covered by this report were designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is (1) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and (2) accumulated and communicated to our management, including our chief executive officer and our chief financial officer, as appropriate to allow timely decisions regarding required disclosure. Based on their evaluation, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures were effective to achieve the foregoing objectives as of the end of the period covered by this report.

There were no changes in our internal control over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) under the U.S. Securities Exchange Act of 1934. Our 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. 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.

Our management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2012. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control — Integrated Framework. Based on our assessment, we have concluded that, as of December 31, 2012, our internal control over financial reporting is effective based on those criteria.

Our independent registered public accounting firm has audited our internal control over financial reporting as of December 31, 2012, as stated in their report entitled "Report of Independent Registered Public Accounting Firm" which appears in Item 8 of this annual report.

Item 9B. Other Information

None.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated by reference to our definitive proxy statement, which is to be filed with the SEC pursuant to the Securities Exchange Act of 1934 within 120 days after the end of our fiscal year on December 31, 2012.

Code of Business Conduct and Ethical Practices

We have adopted a Code of Business Conduct and Ethics, which applies to, among others, our principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions. We have posted a copy of the code in the “Corporate Governance” section of our internet website at [www.herculesoffshore.com](http://www.herculesoffshore.com). Copies of the code may be obtained free of charge on our website or by requesting a copy in writing from our Corporate Secretary at 9 Greenway Plaza, Suite 2200, Houston, Texas 77046. Any waivers of the code must be approved by our board of directors or a designated board committee. Any amendments to, or waivers from, the code that apply to our executive officers and directors will be posted in the “Corporate Governance” section of our internet website at [www.herculesoffshore.com](http://www.herculesoffshore.com).

Item 11. Executive Compensation

The information required by this item is incorporated by reference to our definitive proxy statement, which is to be filed with the SEC pursuant to the Exchange Act within 120 days after the end of our fiscal year on December 31, 2012.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this item is incorporated by reference to our definitive proxy statement, which is to be filed with the SEC pursuant to the Exchange Act within 120 days after the end of our fiscal year on December 31, 2012.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this item is incorporated by reference to our definitive proxy statement, which is to be filed with the SEC pursuant to the Exchange Act within 120 days after the end of our fiscal year on December 31, 2012.

Item 14. Principal Accountant Fees and Services

The information required by this item is incorporated by reference to our definitive proxy statement, which is to be filed with the SEC pursuant to the Exchange Act within 120 days after the end of our fiscal year on December 31, 2012.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following documents are included as part of this report:

- (1) Financial Statements
- (2) Consolidated Financial Statement Schedule on page 101 of this Report.
- (3) The Exhibits of the Company listed below in Item 15(b)

(b) Exhibits

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Exhibit Number	Description
1.1	— Underwriting Agreement, dated September 24, 2009, by and between Hercules Offshore, Inc. and Morgan Stanley & Co. Incorporated and UBS Securities LLC, as representatives of the underwriters named in Schedule A thereto (incorporated by reference to Exhibit 1.1 to Hercules' Current Report on Form 8-K dated September 30, 2009).
1.2	— Underwriting Agreement, dated March 22, 2012, by and between Hercules Offshore, Inc. and Credit Suisse Securities (USA) LLC, Goldman Sachs & Co. and Deutsche Bank Securities Inc., as representatives of the underwriters named in Schedule A thereto (incorporated by reference to Exhibit 1.1 to Hercules' Current Report on Form 8-K dated March 28, 2012).
2.1	— Asset Purchase Agreement, dated February 11, 2011, by and between Hercules Offshore, Inc., SD Drilling LLC and Seahawk Drilling, Inc., Seahawk Global Holdings LLC, Seahawk Mexico Holdings LLC, Seahawk Drilling Management LLC, Seahawk Drilling LLC, Seahawk Offshore Management LLC, Energy Supply International LLC and Seahawk Drilling USA, LLC (incorporated by reference to Exhibit 2.1 to Hercules' Current Report on Form 8-K/A dated February 15, 2011 (File No. 0-51582)).
2.2	— Plan of Conversion (incorporated by reference to Exhibit 2.1 to Hercules' Registration Statement on Form S-1 (Registration No. 333-126457), as amended (the "S-1 Registration Statement"), originally filed on July 8, 2005).
2.3	— Amended and Restated Agreement and Plan of Merger, dated effective as of March 18, 2007, by and among Hercules, THE Hercules Offshore Drilling Company LLC and TODCO (incorporated by reference to Annex A to the Joint Proxy/Statement Prospectus included in Part I of Hercules' Registration Statement on Form S-4 (Registration No. 333-142314), as amended (the "S-4 Registration Statement"), originally filed April 24, 2007).
3.1	— Amended and Restated Certificate of Incorporation of Hercules Offshore, Inc. filed on May 15, 2012 (incorporated by reference to Exhibit 3.1 to Hercules' Current Report on Form 8-K dated May 18, 2012.)
3.2	— Amended and Restated Bylaws (effective December 31, 2009) (incorporated by reference to Exhibit 3.1 to Hercules' Current Report on Form 8-K dated December 8, 2009).
4.1	— Form of specimen common stock certificate (incorporated by reference to Exhibit 4.1 to the S-1 Registration Statement), as amended and filed on October 12, 2005.
4.2	— Rights Agreement, dated as of October 31, 2005, between Hercules and American Stock Transfer & Trust Company, as rights agent (incorporated by reference to Exhibit 4.1 to the 2005 Form 8-K).
4.3	— Amendment No. 1 to Rights Agreement, dated as of February 1, 2008, between Hercules and American Stock Transfer & Trust Company, as rights agent.
4.4	— Second Amendment to Rights Agreement, dated as of February 13, 2012, between Hercules and American Stock Transfer & Trust Company, as rights agent (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K dated February 13, 2012 (the "February 2012 8-K")).
4.5	— Certificate of Designations of Series A Junior Participating Preferred Stock (incorporated by reference to Exhibit 4.2 to the 2005 Form 8-K).
4.6	— Credit Agreement dated as of July 11, 2007 among Hercules, as borrower, its subsidiaries party thereto, as guarantors, UBS AG, Stamford Branch, as issuing bank, administrative agent and collateral agent, Amegy Bank National Association and Comerica Bank, as co-syndication agents, Deutsche Bank AG Cayman Islands Branch and Jefferies Finance LLC, as co-documentation agents, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K dated July 11, 2007 (File No. 0-51582)).

Hercules and its subsidiaries are parties to several debt instruments that have not been filed with the SEC under which the total amount of securities authorized does not exceed 10% of the total assets of Hercules and its subsidiaries on a consolidated basis. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, Hercules agrees to furnish a copy of such instruments to the SEC upon request.

- 4.7 — Indenture, dated as of June 3, 2008, by and between the Company and The Bank of New York Trust Company, National Association as Trustee (incorporated by reference to Exhibit 4.1 to Hercules' Current Report on Form 8-K dated June 3, 2008 (File No. 0-51582)).
- 4.8 — Amendment No. 2 dated as of July 23, 2009, to the Credit Agreement dated July 11, 2007, among Hercules Offshore, Inc., as borrower, its subsidiaries party thereto, as guarantors, and UBS AG, Stamford Branch, as issuing bank, administrative agent and collateral agent, and the lenders party thereto (incorporated by reference to Exhibit 4.1 to Hercules Quarterly Report on Form 10-Q dated July 29, 2009).

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Exhibit Number	Description
4.9	— Indenture dated as of October 20, 2009, by and among Hercules Offshore, Inc., the Guarantors named therein and U.S. Bank National Association as Trustee and Collateral Agent (incorporated by reference to Exhibit 4.1 to Hercules' Current Report on Form 8-K dated October 26, 2009), (the "October 2009 8-K").
4.10	— Form of 10.50% Senior Secured Note due 2017 (included in Exhibit 4.10).
4.11	— Security Agreement dated as of October 20, 2009, by and among Hercules Offshore, Inc. and the Guarantors party thereto and U.S. Bank National Association as Collateral Agent (incorporated by reference to Exhibit 4.3 to the October 2009 8-K).
4.12	— Registration Rights Agreement dated as of October 20, 2009, by and among Hercules Offshore, Inc., the Guarantors named therein and the Initial Purchasers party thereto (incorporated by reference to Exhibit 4.4 to the October 2009 8-K).
4.13	— Form of Indenture between Hercules and the trustee thereunder (the "Senior Trustee") in respect of senior debt securities (incorporated by reference to Exhibit 4.7 to Hercules' Registration Statement on Form S-3 filed December 3, 2010), (the "2010 S-3 Registration Statement").
4.14	— Form of Indenture between Hercules and the trustee thereunder (the "Subordinated Trustee") in respect of subordinated debt securities (incorporated by reference to Exhibit 4.8 to the 2010 S-3 Registration Statement).
4.15	— Amendment No. 3 to Credit Agreement, date as of March 3, 2011, by and among the Company, as borrower, its subsidiaries party thereto, as guarantors, the Issuing Banks (as defined in the Credit Agreement) party thereto, and UBS AG, Stamford Branch, as administrative agent for the Lenders and as collateral agent and instructing beneficiary under the Mortgage Trust Agreement (as defined in the Credit Agreement) for the Secured Parties (as defined in the Credit Agreement) (incorporated by reference to Exhibit 10.1 to Hercules' Current Report on Form 8-K dated March 8, 2011) (File No. 0-51582).
4.16	— Indenture dated as of April 3, 2012, by and among Hercules Offshore, Inc., the Guarantors named therein and U.S. Bank National Association as Trustee and Collateral Agent (incorporated by reference to Exhibit 4.1 to Hercules' Current Report on Form 8-K dated April 6, 2012 (the "April 2012 8-K")).
4.17	— Form of 7.125% Senior Secured Note due 2017 (included in Exhibit 4.18).
4.18	— Indenture dated as of April 3, 2012, by and among Hercules Offshore, Inc., the Guarantors named therein and U.S. Bank National Association as Trustee (incorporated by reference to Exhibit 4.3 to the April 2012 8-K).
4.19	— Form of 10.25% Senior Note due 2019 (included in Exhibit 4.20).
4.20	— Credit Agreement dated as of April 3, 2012, among Hercules Offshore, Inc., the Guarantors named therein, the lenders party thereto, Deutsche Bank Trust Company Americas, as administrative agent, collateral agent and issuing bank, and the other agents party thereto (incorporated by reference to Exhibit 4.5 to the April 2012 8-K).
†10.1	— Amended and Restated Executive Employment Agreement, dated February 28, 2012, between the Company and John T. Rynd (incorporated by reference to Exhibit 10.5 to Hercules' Current Report on Form 8-K dated March 2, 2012 (the "March 2012 8-K")).
†10.2	— Amended and Restated Executive Employment Agreement, dated February 28, 2012, between the Company and James W. Noe (incorporated by reference to Exhibit 10.6 to the March 2012 8-K).
†10.3	— Amended and Restated Executive Employment Agreement, dated February 28, 2012, between the Company and Stephen M. Butz (incorporated by reference to Exhibit 10.7 to the March 2012 8-K).
†10.4	—

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Amended and Restated Executive Employment Agreement, dated February 28, 2012, between the Company and Terrell L. Carr (incorporated by reference to Exhibit 10.8 to the March 2012 8-K).

†10.5 — Amended and Restated Executive Employment Agreement, dated February 28, 2012, between the Company and Troy L. Carson (incorporated by reference to Exhibit 10.6 to the March 2012 8-K).

†10.6 — Form of Indemnification Agreement (incorporated by reference to Exhibit 10.1 to Hercules' Current Report on Form 8-K dated April 7, 2006 (File No. 0-51582)).

†10.7 — Hercules Offshore, Inc. Amended and Restated Deferred Compensation Plan (incorporated by reference to Exhibit 10.18 to Hercules' Annual Report on Form 10-K for the year ended December 31, 2008 (File No. 0-51582)).

†10.8 — Hercules Offshore, Inc. HERO Annual Performance Bonus Plan (incorporated by reference to Exhibit 10.1 to Hercules' Current Report on Form 8-K dated December 21, 2011).

†10.9 — Hercules Offshore Amended and Restated 2004 Long-Term Incentive Plan (incorporated by reference to Appendix A to Hercules' Proxy Statement on Schedule 14A filed March 25, 2011 (File No. 0-51582)).

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Exhibit Number	Description
†10.10	— Second Amendment to Hercules Offshore, Inc. Amended and Restated 2004 Long-Term Incentive Plan dated February 13, 2012 (incorporated by reference to Exhibit 10.1 to Hercules' Current Report on Form 8-K dated February 16, 2012).
†10.11	— Form of Phantom Stock Agreement for Chief Executive Officer (incorporated by reference to Exhibit 10.3 to Hercules Quarterly Report on Form 10-K filed July 27, 2012 (the "July 2012 10-Q")).
†10.12	— Form of Phantom Stock Agreement for employees (incorporated by reference to Exhibit 10.4 to the July 2012 10-Q).
†10.13	— Form of Stock Option Award Agreement (incorporated by reference to Exhibit 10.1 to Hercules' Current Report on Form 8-K dated March 3, 2009).
†10.14	— Form of Restricted Stock Agreement for Employees and Consultants (incorporated by reference to Exhibit 10.16 to Hercules' Annual Report on Form 10-K for the year ended December 31, 2008 (File No. 0-51582)).
†10.15	— Form of Restricted Stock Agreement for Directors (incorporated by reference to Exhibit 10.14 to Hercules' Annual Report on Form 10-K for the year ended December 31, 2006 (File No. 0-51582)).
†10.16	— Form of Restricted Stock Agreement (Performance Grant) (incorporated by reference to Exhibit 10.1 to Hercules' Quarterly Report on Form 10-Q for the quarter ended March 31, 2011).
†10.17	— Performance Award Agreement, dated January 1, 2011, between Hercules and John T. Rynd (incorporated by reference to Exhibit 10.27 to Hercules' Annual Report on Form 10-K for the year ended December 31, 2010 (File No. 0-51582)) (the "2010 Form 10-K").
†10.18	— Performance Award Agreement, dated January 1, 2011, between Hercules and John T. Rynd (incorporated by reference to Exhibit 10.28 to the 2010 Form 10-K).
†10.19	— Special Retention Award Agreement, dated January 1, 2011, between Hercules and John T. Rynd (incorporated by reference to Exhibit 10.29 to the 2010 Form 10-K).
10.20	— Registration Rights Agreement, dated as of July 8, 2005, between Hercules and the holders listed on the signature page thereto (incorporated by reference to Exhibit 10.9 to Hercules' Annual Report on Form 10-K for the year ended December 31, 2005 (File No. 0-51582)).
10.21	— Increase Joinder, dated as of April 28, 2008, among Hercules, as borrower, its subsidiaries party thereto, the incremental lenders and other lenders party thereto, and UBS AG Stamford Branch, as administrative agent for the lenders party thereto (incorporated by reference to Exhibit 10.1 to Hercules' Current Report on Form 8-K dated April 30, 2008 (File No. 0-51582)).
10.22	— Purchase Agreement, dated May 28, 2008, by and between the Company and Goldman, Sachs & Co., Banc of America Securities LLC and UBS Securities LLC, as representatives of the Initial Purchasers (incorporated by reference to Exhibit 10.1 to Hercules' Current Report on Form 8-K dated June 3, 2008 (File No. 0-51582)).
10.23	— Asset Purchase Agreement, dated April 3, 2006, by and between Hercules Liftboat Company, LLC and Laborde Marine Lifts, Inc. (incorporated by reference to Exhibit 10.1 to Hercules' Current Report on Form 8-K dated April 3, 2006 (File No. 0-51582)).
10.24	— Asset Purchase Agreement, dated as of August 23, 2006, by and among Hercules International Holdings, Ltd., Halliburton West Africa Ltd. and Halliburton Energy Services Nigeria Limited (incorporated by reference to Exhibit 10.1 to Hercules' Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 0-51582)).
10.25	— First Amendment to Asset Purchase Agreement, dated as of November 1, 2006, by and among Hercules International Holdings, Ltd., Hercules Oilfield Services Ltd., Halliburton West Africa

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Ltd. and Halliburton Energy Services Nigeria Limited (incorporated by reference to Exhibit 10.2 to Hercules' Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 0-51582)).

10.26

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Earnout Agreement, dated November 7, 2006, by and among Hercules Oilfield Services, Ltd., Halliburton West Africa Ltd. and Halliburton Energy Services Nigeria Limited (incorporated by reference to Exhibit 10.3 to Hercules' Current Report on Form 8-K dated November 7, 2006 (File No. 0-51582)).

10.27

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Basic Form of Exchange Agreement between the Company and certain holders of our 3.375% Convertible Senior Notes due 2038 (incorporated by reference to Exhibit 10.1 to Hercules' Current Report on Form 8-K dated June 18, 2009).

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Exhibit Number	Description
10.28	— Purchase Agreement, dated October 8, 2009, by and among Hercules Offshore, Inc., the guarantors party thereto, UBS Securities LLC, Banc of America Securities LLC, Deutsche Bank Securities Inc. and Morgan Stanley & Co. Incorporated, as representatives of the initial purchasers named in Schedule I thereto (incorporated by reference to Exhibit 10.1 to Hercules' Current Report on Form 8-K dated October 14, 2009).
10.29	— Intercreditor Agreement dated as of October 20, 2009, among Hercules Offshore, Inc., the subsidiaries party thereto as guarantors, UBS AG, Stamford Branch, as Bank Collateral Agent and U.S. Bank National Association, as Notes Collateral Agent (incorporated by reference to Exhibit 10.1 to Hercules' Current Report on Form 8-K dated October 26, 2009).
†10.30	— Form of Restricted Stock Agreement for Executive Officers (incorporated by reference to Exhibit 10.1 to Hercules' Current Report on Form 8-K dated March 2, 2012 (the "March 2012 8-K")).
†10.31	— Form of Stock Option Award Agreement for Executive Officers (incorporated by reference to Exhibit 10.2 to the March 2012 8-K).
†10.32	— Form of Restricted Stock Agreement for Non-Executive Employees and Consultants (incorporated by reference to Exhibit 10.3 to the March 2012 8-K).
†10.33	— Form of Stock Option Award Agreement for Non-Executive Employees and Consultants (incorporated by reference to Exhibit 10.4 to the March 2012 8-K).
10.34	— Purchase Agreement, dated March 27, 2012, by and among Hercules Offshore, Inc., the guarantors party thereto, Deutsche Bank Securities Inc., Credit Suisse Securities (USA) LLC, Goldman, Sachs & Co. and UBS Securities LLC, as representatives of the initial purchasers named in Schedule I thereto (incorporated by reference to Exhibit 10.1 to Hercules' Current Report on Form 8-K dated March 30, 2012).
10.35	— Representative Supplement No. 1 dated as of April 3, 2012, among Hercules Offshore, Inc., the subsidiaries party thereto as guarantors, Deutsche Bank Trust Company Americas, as Controlling Agent for the Senior Secured Parties and Authorized Representatives for the Senior Loan Secured Parties and U.S. Bank National Association, as New Representative (incorporated by reference to Exhibit 10.1 to Hercules' Current Report on Form 8-K dated April 6, 2012).
10.36	— Joinder, Resignation and Acknowledgment dated as of April 3, 2012, among Hercules Offshore, Inc., the subsidiaries party thereto, UBS AG, Stamford Branch, as resigning Bank Collateral Agent and as resigning Controlling Agent, and Deutsche Bank Trust Company Americas, as Authorized Representative for new Senior Loan Secured Parties, as new Bank Collateral Agent, and as new Controlling Agent (incorporated by reference to Exhibit 10.2 to Hercules' Current Report on Form 8-K dated April 6, 2012).
*21.1	— Subsidiaries of Hercules.
*23.1	— Consent of Ernst & Young LLP.
*31.1	— Certification of Chief Executive Officer of Hercules pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	— Certification of Chief Financial Officer of Hercules pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	— Certification of the Chief Executive Officer and the Chief Financial Officer of Hercules pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101.INS	XBRL Instance Document
*101.SCH	XBRL Schema Document
*101.CAL	XBRL Calculation Linkbase Document
*101.DEF	XBRL Definition Linkbase Document

\*101.LAB XBRL Label Linkbase Document  
\*101.PRE XBRL Presentation Linkbase Document

Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). Users of this data are advised pursuant to Rule 406T of Regulations S-T that the interactive data filed is deemed not filed or part of a registration statement or prospectus for purposes of Section 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of Section 18 of the Securities Exchange Act 1934, and otherwise not subject to liability under these sections. The financial information contained in the XBRL-related documents is “unaudited” or “unreviewed.”

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- \* Filed herewith.  
† Compensatory plan, contract or arrangement.  
(c) Financial Statement Schedules  
(1) Valuation and Qualifying Accounts and Allowances

## SCHEDULE II

HERCULES OFFSHORE, INC. AND SUBSIDIARIES  
VALUATION AND QUALIFYING ACCOUNTS AND ALLOWANCES  
FOR THE THREE YEARS ENDED DECEMBER 31, 2012

Description	Balance at Beginning of Period (in thousands)	Additions Charged to Expense, Net	Adjustments	Deductions	Balance at End of Period
Year Ended December 31, 2012: Allowance for doubtful accounts receivable	\$ 11,460	\$ (8,847 )	\$ —	\$ (1,825 )	\$ 788
Year Ended December 31, 2011: Allowance for doubtful accounts receivable	\$ 29,798	\$ (13,623 )	\$ —	\$ (4,715 )	\$ 11,460
Year Ended December 31, 2010: Allowance for doubtful accounts receivable	\$ 38,522	\$ 182	\$ —	\$ (8,906 )	\$ 29,798

All other financial statement schedules have been omitted because they are not applicable or not required, or the information required thereby is included in the consolidated financial statements or the notes thereto included in this annual report.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, State of Texas, on February 28, 2013.

HERCULES OFFSHORE, INC.

By: /S/ JOHN T. RYND  
John T. Rynd  
Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on February 28, 2013.

Signatures	Title
/S/ JOHN T. RYND John T. Rynd	Chief Executive Officer and President (Principal Executive Officer)
/S/ STEPHEN M. BUTZ Stephen M. Butz	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/S/ TROY L. CARSON Troy L. Carson	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)
/S/ THOMAS R. BATES, JR. Thomas R. Bates, Jr.	Chairman of the Board
/S/ THOMAS N. AMONETT Thomas N. Amonett	Director
/S/ SUZANNE V. BAER Suzanne V. Baer	Director
/S/ THOMAS M HAMILTON Thomas M Hamilton	Director
/S/ THOMAS J. MADONNA Thomas J. Madonna	Director
/S/ F. GARDNER PARKER F. Gardner Parker	Director
/S/ THIERRY PILENKO Thierry Pilenko	Director
/S/ STEVEN A. WEBSTER Steven A. Webster	Director

