HELIX ENERGY SOLUTIONS GROUP INC
Form 10-K
February 22, 2013

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

Form 10-K

R	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
	For the fiscal year ended December 31, 2012
	OR
£	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
	For the transition period from to

Commission File Number 001-32936

HELIX ENERGY SOLUTIONS GROUP, INC.
(Exact name of registrant as specified in its charter)

Minnesota (State or other jurisdiction of incorporation or organization)	95-3409686 (I.R.S. Employer Identification No.)
400 North Sam Houston Parkway East Suite 400 Houston, Texas (Address of principal executive offices)	77060 (Zip Code)

(281) 618-0400
(Registrant’s telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock (no par value)	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.   R 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 R 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. R 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). R 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. (Check one):

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant based on the last reported sales price of the Registrant's Common Stock on June 30, 2012 was approximately $1.6 billion.

The number of shares of the registrant's Common Stock outstanding as of February 19, 2013 was 105,881,630.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement for the Annual Meeting of Shareholders to be held on May 7, 2013, are incorporated by reference into Part III hereof.

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Forward Looking Statements

This Annual Report on Form 10-K (“Annual Report”) contains various statements that contain forward-looking information regarding Helix Energy Solutions Group, Inc. and represent our expectations and beliefs concerning future events. This forward looking information is intended to be covered by the safe harbor for “forward-looking statements” provided by the Private Securities Litigation Reform Act of 1995 as set forth in Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements, included herein or incorporated herein by reference, that are predictive in nature, that depend upon or refer to future events or conditions, or that use terms and phrases such as “achieve,” “anticipate,” “believe,” “estimate,” “expect,” “forecast,” “plan,” “project,” “propose,” “strategy,” “predict,” “envision,” “hope,” “intend,” “will,” “cont “potential,” “should,” “could” and similar terms and phrases are forward-looking statements. Included in forward-looking statements are, among other things:

- statements regarding our business strategy or any other business plans, forecasts or objectives, any or all of which is subject to change;
- the timing of the closing of our pipelay vessel sales in 2013;
- statements relating to the construction or acquisition of vessels or equipment and any anticipated costs related thereto, including the construction of the Q5000 and the upgrades and modifications of the Helix 534 as discussed in Item 1. Business “— Contracting Services Operations”;
- statements regarding projections of revenues, gross margin, expenses, earnings or losses, working capital or other financial items;
- statements regarding any financing transactions or arrangements, or ability to enter into such transactions;
- statements regarding anticipated legislative, governmental, regulatory, administrative or other public body actions, requirements, permits or decisions;
- statements regarding the collectability of our trade receivables;
- statements regarding anticipated developments, industry trends, performance or industry ranking;
- statements regarding general economic or political conditions, whether international, national or in the regional and local market areas in which we do business;
- statements related to our ability to retain key members of our senior management and key employees;
- statements related to the underlying assumptions related to any projection or forward-looking statement; and
- any other statements that relate to non-historical or future information.

Although we believe that the expectations reflected in these forward-looking statements are reasonable and are based on reasonable assumptions, they do involve risks, uncertainties and other factors that could cause actual results to be materially different from those in the forward-looking statements. These factors include, among other things:

- impact of weak domestic and global economic conditions and the future impact of such conditions on the oil and gas industry and the demand for our services;
- unexpected delays in the delivery or chartering of our new vessels to our well intervention fleet, including the Helix 534 and Skandi Constructor in 2013 and the Q5000 in 2015;
- delays, costs and difficulties related to the pipelay vessel sales in 2013;
- unexpected future capital expenditures (including the amount and nature thereof);
-

the effects of indebtedness, which could adversely restrict our ability to operate, could make us vulnerable to general adverse economic and industry conditions, could place us at a competitive disadvantage compared to our competitors that have less debt and could have other adverse consequences to us;

- the results of our continuing efforts to control costs and improve performance;
- the success of our risk management activities;
- the effects of competition;
- the availability (or lack thereof) of capital (including any financing) to fund our business strategy and/or operations, and the terms of any such financing;
- the impact of current and future laws and governmental regulations, including tax and accounting developments;
- the effect of adverse weather conditions and/or other risks associated with marine operations;
- the effectiveness of our future hedging activities;

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- the potential impact of a loss of one or more key employees; and
- the impact of general, market, industry or business conditions.

Our actual results could differ materially from those anticipated in any forward-looking statements as a result of a variety of factors, including those discussed in “Risk Factors” beginning on page 16 of this Annual Report. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these risk factors. Forward-looking statements are only as of the date they are made, and other than as required under the securities laws, we assume no obligation to update or revise these forward-looking statements or provide reasons why actual results may differ.

PART I

Item 1. Business

OVERVIEW

Helix Energy Solutions Group, Inc. (together with its subsidiaries, unless context requires otherwise, “Helix”, the “Company”, “we,” “us” or “our”) is an international offshore energy company that provides specialty services to the offshore energy industry, with a focus on our growing well intervention and robotics operations. On February 6, 2013, we sold Energy Resource Technology GOM, Inc. (“ERT”), a former wholly-owned U.S. subsidiary that conducted our oil and gas operations in the Gulf of Mexico, for $620 million plus contingent consideration in the form of overriding royalty interests in the Wang well and certain other future exploration prospects. We used $318.4 million of the sales proceeds to reduce our indebtedness under our Credit Agreement (Note 7) and we will use the remainder to continue to support the expansion of our well intervention and robotics operations. For detailed information regarding our strategy and our business operations, see sections titled “Our Strategy,” “Contracting Services Operations” and “Oil and Gas Operations” included elsewhere within Item 1. Business of this Annual Report.

As of December 31, 2012, we had two continuing reporting business segments: Contracting Services and Production Facilities. Our Contracting Services seek to provide services and methodologies which we believe are critical to developing offshore reservoirs and maximizing production economics. Our “life of field” services are segregated into four disciplines: well intervention, robotics, subsea construction and production facilities. We aggregate the first three of these disciplines into our Contracting Services segment. Our Contracting Services segment conducts its operations primarily in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions. Our Production Facilities segment consists of our majority ownership of a dynamically positioned floating production vessel (the “Helix Producer I” or “HP I”), our equity investments in two production facilities in hub locations, and the Helix Fast Response System (“HFRS”). All of our production facilities activities are located in the Gulf of Mexico. Our former Oil and Gas segment was engaged in prospect generation, exploration, development and production activities all within the Gulf of Mexico.

Our principal executive offices are located at 400 North Sam Houston Parkway East, Suite 400, Houston, Texas 77060; phone number 281-618-0400. Our common stock trades on the New York Stock Exchange (“NYSE”) under the ticker symbol “HLX.” Our Chief Executive Officer submitted the annual CEO certification to the NYSE as required under its Listed Company Manual in May 2012. Our principal executive officer and our principal financial officer have made the certifications required under Section 302 of the Sarbanes-Oxley Act, which are included as exhibits to this Annual Report.

Please refer to the subsection “— Certain Definitions” on page 14 for definitions of additional terms commonly used in this Annual Report. Unless otherwise indicated any reference to Notes herein refers to our Notes to Consolidated Financial Statements in Item 8. Financial Statements and Supplementary Data located elsewhere in this Annual Report.

BACKGROUND

Helix was incorporated in the state of Minnesota in 1979. Until June 2009, Helix owned the majority of the common stock of a separate publicly-traded entity, Cal Dive International, Inc. (NYSE: DVR, and collectively with its subsidiaries referred to as “Cal Dive” or “CDI”), which performed shelf contracting services. Helix sold substantially all of its ownership interests in Cal Dive during 2009 and its remaining ownership interest in 2011 (Note 2). In October 2012, we announced transactions to sell our remaining pipelay vessels and related assets, the sales of which are expected to close during 2013. In February 2013, we sold ERT (see “Oil and Gas Operations” below).

OUR STRATEGY

Over the past few years, we have improved our balance sheet and increased our liquidity through dispositions of non-core business assets as well as reductions in capital spending and the amount of our debt outstanding. With this goal substantially accomplished with the sale of ERT and the expected sales of our remaining pipelay vessels and related equipment, we are now positioned to expand and grow our remaining operations.

Our current focus is to expand our Contracting Services capabilities by growing our well intervention and robotics operations. We believe that focusing on these services will deliver higher long-term financial returns to us than the businesses and assets that we have chosen to monetize. We are making strategic investments that expand our service capabilities or add capacity to existing services in our key operating regions. We are strengthening our well intervention fleet by constructing a newbuild semisubmersible vessel, the Q5000, acquiring the Discoverer 534 drillship (renamed the Helix 534) which is currently undergoing upgrades and modifications in Singapore to render it suitable for use as a well intervention vessel, and chartering the Skandi Constructor for use in our North Sea and Canadian well intervention operations. In addition, we are expanding our robotics operations by acquiring additional remotely operated vehicles (“ROVs”) and trenchers as well as taking delivery of a newbuild chartered ROV support vessel, the Grand Canyon. We also plan to charter two similar vessels, the Grand Canyon II and Grand Canyon III.

CONTRACTING SERVICES OPERATIONS

We seek to provide services and methodologies which we believe are critical to developing offshore reservoirs and maximizing production economics. Our “life of field” services are segregated into four disciplines: well intervention, robotics, subsea construction and production facilities. We have disaggregated our contracting service operations into two reportable segments: Contracting Services and Production Facilities. Our Contracting Services segment includes well intervention, robotics and subsea construction operations (read Subsea Construction below regarding the planned dispositions of our subsea construction vessels and related assets). Our Production Facilities segment includes our majority ownership of the HP I vessel, our equity investments in Deepwater Gateway, L.L.C. (“Deepwater Gateway”) and Independence Hub, LLC (“Independence Hub”), and the HFRS. We provide a full range of contracting services primarily in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions primarily in deepwater. Our current services include:

- Production. Inspection, repair and maintenance of production structures, trees, jumpers, risers, pipelines and subsea equipment; well intervention; life of field support; and intervention engineering.

- Reclamation. Reclamation and remediation services; plugging and abandonment services; pipeline abandonment services; and site inspections.

- Development. Installation of subsea pipelines, flowlines, control umbilicals, manifold assemblies and risers; pipelay and burial; installation and tie-in of riser and manifold assembly; commissioning, testing and inspection; and cable and umbilical lay and connection. We have experienced increased demand for our services from the alternative energy industry. Some of the services we provide to these alternative energy businesses include subsea power cable installation, trenching and burial, along with seabed coring and preparation for construction of wind turbine foundations.

- Production facilities. We are able to provide oil and natural gas processing services to oil and natural gas companies, primarily those operating in the deepwater of the Gulf of Mexico using our HP I vessel. Currently, the HP I is being utilized to process production from the Phoenix field (Note 3). In addition to the services provided by our HP I vessel, we maintain equity investments in two production hub facilities in the Gulf of Mexico. We also established the HFRS as a response resource that can be identified in permit applications to federal and state agencies.

As of December 31, 2012, backlog for our contracting services operations which is supported by written agreements or contracts totaled $829.6 million, of which $554.4 million is expected to be performed in 2013. At December 31, 2011, our backlog totaled $539.6 million. These backlog contracts are cancellable

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without penalty in many cases. Backlog is not a reliable indicator of total annual revenue for our contracting services operations as contracts may be added, cancelled and in many cases modified while in progress.

Demand for our contracting services operations is primarily influenced by the condition of the oil and gas industry, and in particular, the willingness of oil and gas companies to make capital expenditures for offshore exploration, drilling and production operations. Generally, spending for our contracting services fluctuates directly with the direction of oil and natural gas prices.

We believe that the long-term industry fundamentals are positive based on the following factors: (1) long-term increasing world demand for oil and natural gas emphasizing the need for continual replenishment of oil and gas production; (2) mature global production rates for offshore and subsea wells; (3) globalization of the natural gas market; (4) increasing number of mature and small reservoirs; (5) increasing offshore activity, particularly in deepwater; and (6) increasing number of subsea developments.

Well Intervention

We engineer, manage and conduct well construction, intervention and asset retirement operations in water depths ranging from 200 to 10,000 feet. The increased number of subsea wells installed and the periodic shortfall in both rig availability and equipment have resulted in an increased demand for well intervention services in the regions in which we operate.

As major and independent oil and gas companies expand operations in the deepwater basins of the world, development of these reserves will often require the installation of subsea trees. Historically, drilling rigs were typically necessary for subsea well intervention to troubleshoot or enhance production, shift sleeves, log wells or perform recompletions. Three of our vessels serve as work platforms for well intervention services at costs that are typically significantly less than offshore drilling rigs. In the Gulf of Mexico, our multi-service semi-submersible vessel, the Q4000, has set a series of well intervention “firsts” in increasingly deeper water without the use of a traditional drilling rig. In 2010, the Q4000 served as a key component in the Macondo well control and containment efforts. The Q4000 also serves an important role in the HFRS that was established in 2011. In the North Sea, the Seawell has provided well intervention and abandonment services for over 800 North Sea subsea wells since 1987. The Well Enhancer has performed well intervention, abandonment and coil tubing services since it joined our fleet in the North Sea region in 2009. Competitive advantages of our vessels are derived from their lower operating costs, together with an ability to mobilize quickly and to maximize production time by performing a broad range of tasks related to intervention, construction, inspection, repair and maintenance. These services provide a cost advantage in the development and management of subsea reservoirs. We expect long-term demand for these services to increase due to the growing number of subsea tree installations.

In March 2012, we executed a contract with a shipyard in Singapore for the construction of a newbuild semisubmersible well intervention vessel, the Q5000. This $386.5 million shipyard contract represents the majority of the expected costs associated with the construction of the Q5000. Under the terms of this contract, payments are made in a fixed percentage of the contract price, together with any variations, on contractually scheduled dates. At December 31, 2012, our total investment in the Q5000 was $139.6 million, including $115.9 million of scheduled payments made to the shipyard in 2012. We plan to spend approximately $140 million on the Q5000 in 2013, including scheduled shipyard payments of $115.9 million. The vessel is expected to be completed and placed in service in 2015.

In July 2012, we contracted to charter the Skandi Constructor for use in our North Sea and Canadian well intervention operations. The initial term of the charter will be three years once the vessel is delivered to us in the first half of 2013.

In August 2012, we acquired the Discoverer 534 drillship from a subsidiary of Transocean Ltd. for $85 million. The vessel, renamed the Helix 534, is currently undergoing upgrades and modifications in Singapore to render it suitable for use as a well intervention vessel. At December 31, 2012, our investment in the acquisition and subsequent upgrades and modifications of the Helix 534 totaled $113.5 million. We estimate that an additional $50 million will be invested before the vessel is ready to be placed in service. The vessel is expected to join our well intervention fleet in the Gulf of Mexico in the third quarter of 2013.

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The results of well intervention operations are reported within our Contracting Services segment (Note 14).

Robotics

We have been actively engaged in robotics for over 25 years. We operate ROVs, trenchers and ROVDrills designed for offshore construction and well intervention services. As global marine construction support moves to deeper waters, the use of ROV systems has increased and the scope of ROV services is becoming even more significant. Our chartered vessels add value by supporting deployment of our ROVs. We provide our customers with vessel availability and schedule flexibility to meet the technological challenges of their subsea activities worldwide. Our robotics assets include 49 ROVs, four trencher systems and two ROVDrills. We operate in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions. We currently charter four vessels to support our robotics operations and we have historically engaged additional vessels on short-term (spot) charters as needed.

In October 2012, we took possession of a newbuild ROV support vessel, the Grand Canyon, which was commissioned specifically for our use under the terms of a long-term charter agreement. The Grand Canyon will mobilize for many of its projects paired with our new T-1200 trenching and burial unit. We also plan to charter two similar vessels, the Grand Canyon II and Grand Canyon III, once they are constructed.

Over the past few years there has been a dramatic increase in offshore activity associated with the growing alternative (renewable) energy industry. Specifically there has been a large increase in the amount of services performed on behalf of the wind turbine industry. As the level of activity for offshore alternative energy projects has increased, so has the need for reliable services and related equipment. Historically, this work was performed with the use of barges and other similar vessels but these types of services are now contracted to vessels such as our Deep Cygnus and Grand Canyon chartered vessels that are more suitable for harsh weather conditions which can occur offshore, especially in northern Europe where wind farming is presently concentrated. In 2012, our robotics operations had 377 vessel utilization days and 16% of global revenues derived from alternative energy contracts. Looking ahead to 2013, our robotics operating unit is positioned to continue to increase the services it provides to a range of clients in the alternative energy business. This increase is expected to include the use of our chartered vessels, ROVs and trenchers (including the new T-1200 trencher system) to provide burial services relating to subsea power cables on key European wind farm developments.

The results of robotics operations are reported within our Contracting Services segment (Note 14).

Subsea Construction

Subsea construction services include the use of umbilical lay and pipelay vessels and ROVs to develop fields in the deepwater. As we focus on the expansion of our well intervention and robotics operations (see “Our Strategy” above), we sold or have announced the expected sales of our subsea construction vessels. In September 2012, we sold the Intrepid for $14.5 million in cash. In October 2012, we entered into an agreement to sell our two remaining pipelay vessels, the Express and the Caesar, and other related pipelay equipment for a total sales price of $238.3 million, of which we have received a $50 million deposit that is only refundable in very limited circumstances. The sales of these vessels are scheduled to close and fund in two stages in 2013 following the completion of each vessel’s existing backlog of work. Currently, we anticipate the Express sale will close in May 2013 and we expect the Caesar sale to close in July 2013. We currently retain our spoolbase facilities located in Ingleside, Texas.

The results of our subsea construction services are reported within our Contracting Services segment (Note 14).

Production Facilities

We own interests in two production facilities in hub locations where there is potential for subsea tieback activity. There are a significant number of small discoveries that cannot justify the economics of a dedicated host facility. These discoveries are typically developed as subsea tie backs to existing facilities when capacity through the facility is available. We have invested in two over-sized facilities that allow the operators of these fields to tie back without burdening the operator of the hub reservoir. Ownership of production facilities enables us to earn a transmission company type return through tariff charges while

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periodically providing construction work for our vessels. We own a 50% interest in Deepwater Gateway, which owns the Marco Polo TLP located in 4,300 feet of water in the Gulf of Mexico. We also own a 20% interest in Independence Hub which owns the Independence Hub platform, a 105-foot deep draft, semi-submersible platform located in a water depth of 8,000 feet that serves as a regional hub for up to one billion cubic feet ("Bcf") of natural gas production per day from multiple ultra-deepwater fields in the eastern Gulf of Mexico.

We also seek to employ oil and gas processing alternatives that permit the development of some fields that otherwise would be non-commercial to develop. For example, through an approximate 81% owned and consolidated entity, we completed the conversion of a vessel (the HP I) into a ship-shaped dynamically positioning floating production unit capable of processing up to 45,000 barrels of oil and 80 MMcf of natural gas per day. The HP I is currently being used to process production from the Phoenix field. Our existing contract for service to the Phoenix field will not expire until at least December 31, 2016. In 2013, we expect the HP I to be in regulatory dry dock which may take two months to complete.

We developed the HFRS as a culmination of our experience as a responder in the Macondo well control and containment efforts. The HFRS centers on two vessels, the HP I and the Q4000, both of which played a key role in the Macondo well control and containment efforts and are presently operating in the Gulf of Mexico. In 2011, we signed an agreement with Clean Gulf Associates ("CGA"), a non-profit industry group, allowing, in exchange for a retainer fee, the HFRS to be named as a response resource in permit applications to federal and state agencies and making the HFRS available to certain CGA participants who have executed utilization agreements with us. In addition to the agreement with CGA, we currently have signed separate utilization agreements with 24 CGA participant member companies specifying the day rates to be charged should the HFRS be deployed in connection with a well control incident. Recently, this group of operators formed HWCG LLC to perform the same functions as CGA with respect to the HFRS. The retainer fee for the HFRS became effective April 1, 2011. We anticipate that a new contract covering the HFRS will be signed in the first quarter of 2013 to provide for a four-year term commencing April 1, 2013.

The results of production facilities services are reported as our Production Facilities segment (Note 14).

OIL AND GAS OPERATIONS

In 1992, we formed our oil and gas business unit to achieve incremental returns, to expand off-season utilization of our contracting services assets, and to develop a more efficient solution to offshore abandonment for industry participants.

In February 2013, we sold ERT to Talos Production LLC ("Talos") for $620 million plus contingent consideration in the form of overriding royalty interests in the Wang well and certain other future exploration prospects. See Note 3 for additional information regarding the sale and operations of ERT.

See Item 2. Properties "— Summary of Oil and Natural Gas Reserve Data" for additional disclosures associated with ERT.

The results of ERT are reported as discontinued operations (Note 3).

GEOGRAPHIC AREAS

Revenue associated with our continuing operations by individually significant country is as follows (in thousands):

	Year Ended December 31,		
	2012	2011	2010

United States	$281,308	$316,869	$402,228
United Kingdom	345,074	275,499	198,011
Other	219,727	109,632	174,230
Total	$846,109	$702,000	$774,469

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We include the property and equipment, net of accumulated depreciation, in the geographic region in which it is legally owned. The following table provides our property and equipment, net of accumulated depreciation, associated with our continuing operations by individually significant country (in thousands):

	Year Ended December 31,		
	2012	2011	2010
United States	$1,180,586	$1,163,320	$1,162,217
United Kingdom	304,062	281,430	275,012
Other	1,227	14,919	15,613
Total	$1,485,875	$1,459,669	$1,452,842

CUSTOMERS

Our customers include major and independent oil and gas producers and suppliers, pipeline transmission companies, alternative (renewable) energy companies and offshore engineering and construction firms. The level of services required by any particular contracting customer depends, in part, on the size of that customer's capital expenditure budget in a particular year. Consequently, customers that account for a significant portion of contract revenues in one fiscal year may represent an immaterial portion of contract revenues in subsequent fiscal years. The percent of consolidated revenue from major customers, those whose total represented 10% or more of our consolidated revenues from continuing operations is as follows: 2012 — Shell (12%), 2011 — Shell (10%) and 2010 — BP plc (26%). The percent of revenue from major customers, those whose total represented 10% or more of our discontinued oil and gas revenues, is as follows: 2012 — Shell (64%) and JP Morgan Ventures (26%); 2011 — Shell (89%); and 2010 — Shell (67%) and Louis Dreyfus Energy Services (19%). We estimate that in 2012 we provided contracting services to over 70 customers.

Our contracting services projects were historically of short duration and generally were awarded shortly before mobilization. However, since 2007, we have entered into many longer term contracts for certain of our well intervention, subsea construction and production facilities vessels. As of December 31, 2012, backlog for our contracting services operations which is supported by written agreements or contracts totaled $829.6 million, of which $554.4 million is expected to be performed in 2013. These backlog contracts are cancellable without penalty in many cases. Backlog is not a reliable indicator of total annual revenue for our contracting services operations as contracts may be added, cancelled and in many cases modified while in progress.

COMPETITION

The contracting services industry is highly competitive. While price is a factor, the ability to acquire specialized vessels, attract and retain skilled personnel, and demonstrate a good safety record is also important. Our principal competitors include Oceaneering International, Inc., Saipem S.p.A., Fugro N.V., DOF ASA, Aker Solutions ASA, Subsea 7 S.A., Technip, McDermott International, Inc., Island Offshore and Edison Chouest Offshore Companies. Our competitors in the well intervention business also include the international drilling contractors. Many of our competitors may have significantly more financial, personnel, technological and other resources available to them.

ERT competed with large integrated oil and gas companies as well as independent exploration and production companies for offshore leases on properties.

TRAINING, SAFETY AND QUALITY ASSURANCE

We have established a corporate culture in which QHSE is of equal priority to our other business objectives. Our corporate goal, based on the belief that all accidents can be prevented, is to provide an incident-free workplace by focusing on risk management and safe behavior. Everyone at Helix has the authority and the duty to "STOP WORK" which they believe is unsafe. Our QHSE management systems and training programs were developed by management personnel based on common industry work practices and by employees with on-site experience who understand the risk and physical challenges of the ocean work site. As a result, management believes that our QHSE programs are among the best in the industry. We maintain a company-wide effort to reduce risks, manage change effectively, enhance and provide continuous

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improvements to the behavior of our people, as well as our training programs, that continue to focus on safety through open communication. The process includes the assessment of risk through the use of selected risk analysis tools, control of work through management system procedures, job risk assessment of all routine and non-routine tasks, documentation of all daily observations, collection of data and data treatment to provide the mechanism of understanding both safe and at-risk behaviors at the worksite. In addition, we schedule hazard hunts by project management on each vessel, and regularly audit QHSE management systems, both are completed with assigned responsibilities and action due dates. Contracting Services Business Units have been independently certified compliant in ISO 9001 (Quality Management Systems) and ISO 14001 (Environmental Management System).

GOVERNMENT REGULATION

Many aspects of the offshore marine construction industry are subject to extensive governmental regulations. We are subject to the jurisdiction of the U.S. Coast Guard ("Coast Guard"), the U.S. Environmental Protection Agency ("EPA"), three divisions of the U.S. Department of the Interior, the Bureau of Ocean Energy Management ("BOEM"), the Bureau of Safety and Environmental Enforcement ("BSEE") and the Office of Natural Resource Revenue ("ONRR") and the U.S. Customs Service, as well as private industry organizations such as the American Bureau of Shipping ("ABS"). In the North Sea, international regulations govern working hours and a specified working environment, as well as standards for diving procedures, equipment and diver health. These North Sea standards are some of the most stringent worldwide. In the absence of any specific regulation, our North Sea operations adhere to standards set by the International Marine Contractors Association and the International Maritime Organization. In addition, we operate in other foreign jurisdictions that have various types of governmental laws and regulations to which we are subject.

The Coast Guard sets safety standards and is authorized to investigate vessel and diving accidents and to recommend improved safety standards. The Coast Guard also is authorized to inspect vessels at will. We are required by various governmental and quasi-governmental agencies to obtain various permits, licenses and certificates with respect to our operations. We believe that we have obtained or can obtain all permits, licenses and certificates necessary for the conduct of our business.

In addition, we depend on the demand for our services from the oil and gas industry, and therefore, our business is affected by laws and regulations, as well as changing tax laws and policies, relating to the oil and gas industry generally. In particular, the development and operation of oil and gas properties located on the OCS of the United States is regulated primarily by the BOEM and BSEE.

The BOEM requires lessees of OCS properties to post bonds or provide other adequate financial assurance in connection with the plugging and abandonment of wells located offshore and the removal of all production facilities.

In April 2010, the Deepwater Horizon drilling rig experienced an explosion and fire, and later sank into the Gulf of Mexico. The complete destruction of the Deepwater Horizon rig also resulted in a significant release of crude oil into the Gulf. As a result of this explosion and oil spill, a moratorium was placed on offshore deepwater drilling in the United States, which was subsequently lifted in October 2010 and replaced with enhanced safety standards for offshore deepwater drilling. Under the enhanced safety standards, in order for an operator to resume deepwater drilling, it is required to comply with existing and newly developed regulations and standards, including Notice to Lessees (NTL), NTL 2010-N06 (Environmental NTL), NTL 2010-N10 (Compliance and Evaluation NTL), and the Final Drilling Safety Rule. Inspections will be conducted of each deepwater drilling operation for compliance with BOEM and BSEE regulations, including but not limited to the testing of blowout preventers, before drilling resumes. As companies resume operations, they will also need to comply with the Safety and Environmental Management System (SEMS) Rule within the deadlines specified by the regulation. Additionally, each operator must demonstrate that it has enforceable obligations that ensure that containment resources are available promptly in the event of a deepwater blowout, regardless of the company or operator involved. During 2011, the Department of the

Interior established a mechanism relating to the availability of blowout containment resources, including our HFRS system, and these resources are now being regulated by the BOEM and BSEE. It is also expected that the BOEM and BSEE will issue further regulations regarding deepwater offshore drilling.

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Additional proposals and proceedings before various federal and state regulatory agencies and the courts could affect the oil and gas industry. We cannot predict when or whether any such proposals may become effective.

ENVIRONMENTAL REGULATION

Our operations are subject to a variety of national (including federal, state and local) and international laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often complex and costly to comply with and that carry substantial administrative, civil and possibly criminal penalties for failure to comply. Under these laws and regulations, we may be liable for remediation or removal costs, damages and other costs associated with releases of hazardous materials (including oil) into the environment, and such liability may be imposed on us even if the acts that resulted in the releases were in compliance with all applicable laws at the time such acts were performed. Some of the environmental laws and regulations that are applicable to our business operations are discussed in the following paragraphs, but the discussion does not cover all environmental laws and regulations that govern our operations.

The Oil Pollution Act of 1990, as amended (“OPA”), imposes a variety of requirements on “Responsible Parties” related to the prevention of oil spills and liability for damages resulting from such spills in waters of the United States. A “Responsible Party” includes the owner or operator of an onshore facility, a vessel or a pipeline, and the lessee or permittee of the area in which an offshore facility is located. OPA imposes liability on each Responsible Party for oil spill removal costs and for other public and private damages from oil spills. Failure to comply with OPA may result in the assessment of civil and criminal penalties. OPA establishes liability limits of $854,400 or $1,000 per gross ton for vessels other than tank vessels. The liability limits are not applicable, however, if the spill is caused by gross negligence or willful misconduct; if the spill results from violation of a federal safety, construction, or operating regulation; or if a party fails to report a spill or fails to cooperate fully in the cleanup. Few defenses exist to the liability imposed under OPA. Management is currently unaware of any oil spills for which we have been designated as a Responsible Party under OPA that will have a material adverse impact on us or our operations.

In addition, OPA requires owners and operators of vessels over 300 gross tons to provide the Coast Guard with evidence of financial responsibility to cover the cost of cleaning up oil spills from such vessels. We currently own and operate seven vessels over 300 gross tons. We have provided satisfactory evidence of financial responsibility to the Coast Guard for all of our vessels.

The Clean Water Act imposes strict controls on the discharge of pollutants into the navigable waters of the United States and imposes potential liability for the costs of remediating releases of petroleum and other substances. The controls and restrictions imposed under the Clean Water Act have become more stringent over time, and it is possible that additional restrictions will be imposed in the future. Permits must be obtained to discharge pollutants into state and federal waters. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System Program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the exploration for, and production of, oil and gas into certain coastal and offshore waters. The Clean Water Act provides for civil, criminal and administrative penalties for any unauthorized discharge of oil and other hazardous substances and imposes liability on responsible parties for the costs of cleaning up any environmental contamination caused by the release of a hazardous substance and for natural resource damages resulting from the release. Many states have laws that are analogous to the Clean Water Act and also require remediation of releases of petroleum and other hazardous substances in state waters. Our vessels routinely transport diesel fuel to offshore rigs and platforms and also carry diesel fuel for their own use. Our vessels transport bulk chemical materials used in drilling activities and also transport liquid mud which contains oil and oil by-products. Offshore facilities and vessels operated by us have facility and vessel response plans to deal with potential spills. We believe that our operations comply in all material respects with the requirements of the Clean

Water Act and state statutes enacted to control water pollution.

OCSLA provides the federal government with broad discretion in regulating the production of offshore resources of oil and gas, including authority to impose safety and environmental protection requirements applicable to lessees and permittees operating in the OCS. Specific design and operational standards may apply to OCS vessels, rigs, platforms, vehicles and structures. Violations of lease conditions or regulations issued pursuant to OCSLA can result in substantial civil and criminal penalties, as well as

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potential court injunctions curtailing operations and cancellation of leases. Because our operations rely on offshore oil and gas exploration and production, if the government were to exercise its authority under OCSLA to restrict the availability of offshore oil and gas leases, such action could have a material adverse effect on our financial condition and results of operations. As of this date, we believe we are not the subject of any civil or criminal enforcement actions under OCSLA.

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") contains provisions requiring the remediation of releases of hazardous substances into the environment and imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons including owners and operators of contaminated sites where the release occurred and those companies who transport, dispose of, or arrange for disposal of hazardous substances released at the sites. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. Third parties may also file claims for personal injury and property damage allegedly caused by the release of hazardous substances. Although we handle hazardous substances in the ordinary course of business, we are not aware of any hazardous substance contamination for which we may be liable.

We operate in foreign jurisdictions that have various types of governmental laws and regulations relating to the discharge of oil or hazardous substances and the protection of the environment. Pursuant to these laws and regulations, we could be held liable for remediation of some types of pollution, including the release of oil, hazardous substances and debris from production, refining or industrial facilities, as well as other assets we own or operate or which are owned or operated by either our customers or our sub-contractors.

A variety of regulatory developments, proposals or requirements and legislative initiatives have been introduced in the domestic and international regions in which we operate that are focused on restricting the emissions of carbon dioxide, methane and other greenhouse gases. For example, the U.S. Congress has from time to time considered legislation to reduce greenhouse gas emissions, and almost one-half of the states already have taken legal measures to reduce greenhouse gas emissions, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs.

In 2007, the U.S. Supreme Court held in Massachusetts, et al. v. EPA that greenhouse gases are an "air pollutant" under the Federal Clean Air Act and thus subject to future regulation. In December 2009, the EPA issued an "endangerment and cause or contribute finding" for greenhouse gases under the Federal Clean Air Act, which allowed the EPA to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Since 2009, the EPA has issued regulations that, among other things, require a reduction in emissions of greenhouse gases from motor vehicles and that impose greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources.

Additionally, in October 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas sources in the United States on an annual basis, beginning in 2011 for emissions occurring in 2010. On November 9, 2010, the EPA expanded its greenhouse reporting rule to include onshore petroleum and natural gas production, offshore petroleum and natural gas production, onshore natural gas processing, natural gas transmission, underground natural gas storage, liquefied natural gas storage, liquefied natural gas import and export, and natural gas distribution facilities. Under these rules, reporting of greenhouse gas emissions from such facilities is required on an annual basis.

Management believes that we are in compliance in all material respects with the applicable environmental laws and regulations to which we are subject. We do not anticipate that compliance with existing environmental laws and regulations will have a material effect upon our capital expenditures, earnings or competitive position. However, changes in the environmental laws and regulations, or claims for damages to persons, property, natural resources or the environment, could result in substantial costs and liabilities, and thus there can be no assurance that we will not incur significant environmental compliance costs in the future.

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INSURANCE MATTERS

The well intervention, robotics and subsea construction operations constituting our contracting services business involve a high degree of operational risk. Hazards, such as vessels sinking, grounding, colliding and sustaining damage from severe weather conditions, are inherent in marine operations. These hazards can cause personal injury or loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and the suspension of operations. Damages arising from such occurrences may result in lawsuits asserting large claims. Insurance may not be sufficient or effective under all circumstances or against all hazards to which we may be subject. A successful claim for which we are not fully insured could have a material adverse effect on our financial condition, results of operations and cash flows.

As discussed above, we maintain insurance policies to cover some of our risk of loss associated with our operations. We maintain the amount of insurance we believe is prudent based on our estimated loss potential. However, not all of our business activities can be insured at the levels we desire because of either limited market availability or unfavorable economics (limited coverage for the underlying cost).

Our energy and marine insurance is renewed annually on July 1 and covers a twelve-month period from July 1 to June 30.

For our contracting services business we maintain Hull and Increased Value insurance, which provides coverage for physical damage up to an agreed amount for each vessel. The deductibles are $1.0 million on the Q4000, HP I and Well Enhancer, $500,000 on the Seawell, Express and Helix 534, and $750,000 on the Caesar. In addition to the primary deductibles, the vessels are subject to an annual aggregate deductible of $5 million. We also carry Protection and Indemnity (“P&I”) insurance which covers liabilities arising from the operation of the vessels and General Liability insurance which covers liabilities arising from construction operations. The deductible on both the P&I and General Liability is $100,000 per occurrence. Onshore employees are covered by Workers’ Compensation. Offshore employees and marine crews are covered by our Maritime Employers Liability insurance policy which covers Jones Act exposures and includes a deductible of $100,000 per occurrence plus a $1.0 million annual aggregate deductible. In addition to the liability policies described above, we currently carry various layers of Umbrella Liability for total limits of $500 million in excess of primary limits. Our self-insured retention on our medical and health benefits program for employees is $250,000 per participant.

We have also maintained Operator Extra Expense coverage that provides up to $150 million of coverage per each loss occurrence for a well control issue. Separately, we also maintain $500 million of liability insurance and $150 million of oil pollution insurance. For any given oil spill event we have up to $650 million of insurance coverage.

We customarily have reciprocal agreements with our customers and vendors in which each contracting party is responsible for its respective personnel. Under these agreements we are indemnified against third party claims related to the injury or death of our customers’ or vendors’ personnel. With respect to well work by our contracting services operations, the customer is generally contractually responsible for pollution emanating from the well. We separately maintain additional coverage for an amount up to $100 million that would cover us under certain circumstances against any such third party claims associated with well control events.

EMPLOYEES

As of December 31, 2012, we had 1,695 employees, approximately 795 of which were salaried personnel. As of December 31, 2012, we also contracted with third parties to utilize 70 non-U.S. citizens to crew our foreign flagged vessels. Our employees do not belong to a union nor are they employed pursuant to any collective bargaining agreement or any similar arrangement. We believe our relationship with our employees and foreign crew members is favorable.

WEBSITE AND OTHER AVAILABLE INFORMATION

We maintain a website on the Internet with the address of www.HelixESG.com. Copies of this Annual Report for the year ended December 31, 2012, and previous and subsequent copies of our Quarterly Reports on Form 10-Q and any Current Reports on Form 8-K, and any amendments thereto, are or will be

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available free of charge at such website as soon as reasonably practicable after they are filed with, or furnished to, the Securities and Exchange Commission ("SEC"). In addition, the Investor Relations portion of our website contains copies of our Code of Conduct and Business Ethics and our Code of Ethics for Chief Executive Officer and Senior Financial Officers. We make our website content available for informational purposes only. Information contained on our website is not part of this report and should not be relied upon for investment purposes. Please note that prior to March 6, 2006, the name of the Company was Cal Dive International, Inc.

The general public may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. We are an electronic filer, and the SEC maintains an Internet website that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC, including us. The Internet address of the SEC's website is www.sec.gov.

We intend to satisfy the requirement under Item 5.05 of Form 8-K to disclose any amendments to our Code of Conduct and Business Ethics and our Code of Ethics for Chief Executive Officer and Senior Financial Officers and any waiver from any provision of those codes by posting such information in the Investor Relations section of our website at www.HelixESG.com.

CERTAIN DEFINITIONS

Defined below are certain terms helpful to understanding our business that are located through this Annual Report:

Bcfe: One billion cubic feet equivalent, with one barrel of oil being equivalent to six thousand cubic feet of natural gas.

BOE: One barrel of oil equivalent, with each six thousand cubic feet of natural gas equivalent to one barrel of oil. Common references in this Annual Report include MBOE, which refers to a thousand barrels of oil equivalent and MMBOE, which refers to a million barrels of oil equivalent.

BOEM: The Bureau of Ocean Energy Management ("BOEM") is responsible for managing environmentally and economically responsible development of the U.S. offshore resources. Its functions include offshore leasing, resource evaluation, review and administration of oil and gas exploration and development plans, renewable energy development, National Environmental Policy Act analysis and environmental studies.

BSEE: The Bureau of Safety and Environmental Enforcement ("BSEE") is responsible for safety and environmental oversight of offshore oil and gas operations, including permitting and inspections, of offshore oil and gas operations. Its functions include the development and enforcement of safety and environmental regulations, permitting offshore exploration, development and production, inspections, offshore regulatory programs, oil spill response and newly formed training and environmental compliance programs.

Deepwater: Water depths exceeding 1,000 feet.

Dynamic Positioning (DP): Computer directed thruster systems that use satellite based positioning and other positioning technologies to ensure the proper counteraction to wind, current and wave forces enabling the vessel to maintain its position without the use of anchors.

DP-2: Two DP systems on a single vessel providing the redundancy which allows the vessel to maintain position even with the failure of one DP system, required for vessels which support both manned diving and robotics and for those working in close proximity to platforms. DP-2 is necessary to provide the redundancy required to support safe deployment of divers, while only a single DP system is necessary to support ROV operations.

IRM: Inspection, repair and maintenance.

Life of Field Services: Services performed on offshore facilities, trees and pipelines from the beginning to the end of the economic life of an oil field, including installation, inspection, maintenance, repair, well intervention and abandonment.

MBbl: When describing oil or other natural gas liquid, refers to 1,000 barrels with each barrel containing 42 gallons.

MMBbl: When describing oil or other natural gas liquid, refers to millions of barrels.

Mcf: When describing natural gas, refers to 1 thousand cubic feet.

MMcf: When describing natural gas, refers to 1 million cubic feet.

Outer Continental Shelf (OCS): For purposes of our industry, areas in the Gulf of Mexico from the shore to 1,000 feet of water depth.

Proved Developed Non-Producing (PDNP): Proved developed oil and gas reserves that are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, or (2) wells that require additional completion work or future recompletion prior to the start of production.

Proved Developed Shut-In (PDSI): Proved developed oil and gas reserves associated with wells that exhibited calendar year production, but were not online January 1, 2012.

Proved Developed Reserves (PDP): Reserves that geological and engineering data indicate with reasonable certainty to be recoverable today, or in the near future, with current technology and under current economic conditions.

Proved Undeveloped Reserves (PUD): Proved undeveloped oil and gas reserves that are expected to be recovered from a new well on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

QHSE: Quality, Health, Safety and Environmental programs to protect the environment, safeguard employee health and avoid injuries.

Remotely Operated Vehicle (ROV): Robotic vehicles used to complement, support and increase the efficiency of diving and subsea operations and for tasks beyond the capability of manned diving operations.

ROVDrill: ROV deployed coring system developed to take advantage of existing ROV technology. The coring package, deployed with the ROV system, is capable of taking cores from the seafloor in water depths up to 3,000 meters. Because the system operates from the seafloor there is no need for surface drilling strings and the larger support spreads required for conventional coring.

Saturation Diving: Saturation diving, required for work in water depths between 200 and 1,000 feet, involves divers working from special chambers for extended periods at a pressure equivalent to the pressure at the work site.

Spar: Floating production facility anchored to the sea bed with catenary mooring lines.

Spot Market: Prevalent market for subsea contracting in the Gulf of Mexico, characterized by projects that are generally short in duration and often on a turnkey basis. These projects often require constant rescheduling and the availability or interchangeability of multiple vessels.

Subsea Construction Vessels: Subsea services are typically performed with the use of specialized construction vessels which provide an above-water platform that functions as an operational base for divers and ROVs. Distinguishing characteristics of subsea construction vessels include DP systems, saturation diving capabilities, deck space, deck load, craneage and moonpool launching. Deck space, deck load and craneage are important features of a vessel's ability to transport and fabricate hardware, supplies and equipment necessary to complete subsea projects.

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Tension Leg Platform (TLP): A floating production facility anchored to the seabed with tendons.

Trencher or Trencher System: A subsea robotics system capable of providing post lay trenching, inspection and burial (PLIB) and maintenance of submarine cables and flowlines in water depths of 30 to 7,200 feet across a range of seabed and environmental conditions.

Well Intervention Services: Activities related to well maintenance and production management/enhancement services. Our well intervention operations include the utilization of slickline and electric line services, pumping services, specialized tooling and coiled tubing services.

Working Interest: The interest in an oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and to a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

Item 1A. Risk Factors

Shareholders should carefully consider the following risk factors in addition to the other information contained herein. You should be aware that the occurrence of the events described in these risk factors and elsewhere in this Annual Report could have a material adverse effect on our business, results of operations and financial position.

Business Risks

Our results of operations could be adversely affected if our business assumptions do not prove to be accurate or if adverse changes occur in our business environment, including the following areas:

- changes in laws or regulations, including laws relating to the environment or to the oil and gas industry in general, and other factors, many of which are beyond our control;
- general global economic and business conditions, which affect demand for oil and natural gas and, in turn, our business;
- our ability to manage risks related to our business and operations;
- our ability to manage shipyard construction and upgrades and modifications of our vessels;
- our ability to manage risks related to the planned dispositions of our remaining pipelay vessels and related equipment;
- our ability to compete against companies that provide more services and products than we do, including “integrated service companies”;
- our ability to attract and retain skilled, trained personnel to provide technical services and support for our business;
- our ability to procure sufficient supplies of materials essential to our business in periods of high demand, and to reduce our commitments for such materials in periods of low demand; and
- consolidation by our customers, which could result in loss of a customer.

Enhanced regulations for deepwater drilling offshore the United States may reduce the need for our services in the Gulf of Mexico.

Under enhanced safety standards, in order for an operator to conduct deepwater drilling, it is required to comply with existing and newly developed regulations and standards. The BSEE conducts many inspections of deepwater drilling operations for compliance with its regulations, including but not limited to the testing of blowout preventers, before drilling may commence. Companies also need to comply with the Safety and Environmental Management System (SEMS Rule) within the deadlines specified by the regulation, and are ensuring that their contractors have SEMS compliant safety and environmental policies. Additionally, each operator must demonstrate that it has enforceable obligations that ensure that containment resources are available promptly in the event of a deepwater blowout, regardless of the company or operator involved. It is expected that the BOEM and BSEE will continue to issue further regulations regarding deepwater offshore drilling. Our contracting services business, a significant portion of which is in the Gulf of Mexico, provides development services to newly drilled wells, and therefore relies heavily on the industry's drilling of new oil and gas wells. With respect to our services business, if the issuance of permits is significantly delayed, or if demand for our services is decreased or delayed because other oil and gas operations are delayed or reduced due to increased costs, demand for our services in the Gulf of Mexico may also decline. Moreover, if our vessels are not redeployed to other locations where we can provide our services at a profitable rate, our business, financial condition and results of operations would be materially affected.

The potential increased costs of complying with new regulations on offshore drilling in the U.S. Gulf of Mexico and potentially in other areas around the world, may impact the need for our services in those areas.

We cannot predict with any certainty the substance or effect of any new or additional regulations in the United States or in other areas around the world including the increase in costs or delays associated with such regulations. If the United States or other countries where we operate enact stricter restrictions on offshore drilling or further regulate offshore drilling and increase costs for our customers, our business, financial condition and results of operations could be materially affected.

Government Regulation, including recent legislative initiatives, may affect our business operations.

Numerous federal and state regulations affect our operations. Current regulations are constantly reviewed by the various agencies at the same time that new regulations are being considered and implemented, and could include regulations pertaining to contracting service operators such as ourselves. The regulatory burden upon the oil and gas industry increases the cost of doing business and consequently affects our profitability. Potential legislation and/or regulatory actions could increase our costs and reduce our liquidity, delay our operations or otherwise alter the way we conduct our business. Exploration and development activities and the production and sale of oil and gas are subject to extensive federal, state, local and international regulations.

Our operations are subject to a variety of national (including federal, state and local) and international laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous domestic and foreign governmental agencies issue rules and regulations to implement and enforce such laws that are often complex and costly to comply with and that carry substantial administrative, civil and possibly criminal penalties for failure to comply. Under these laws and regulations, we may be liable for remediation or removal costs, damages and other costs associated with releases of hazardous materials, including oil into the environment, and such liability may be imposed on us even if the acts that resulted in the releases were in compliance with all applicable laws at the time such acts were performed.

A variety of regulatory developments, proposals or requirements and legislative initiatives have been introduced in the domestic and international regions in which we operate that are focused on restricting the emission of carbon dioxide, methane and other greenhouse gases. For example, the U.S. Congress has from time to time considered legislation to reduce greenhouse gas emissions, and almost one-half of the states already have taken legal measures to reduce greenhouse gas emissions, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs.

In 2007, the U.S. Supreme Court held in Massachusetts, et al. v. EPA that greenhouse gases are an “air pollutant” under the federal Clean Air Act and thus subject to future regulation. In December 2009, the U.S. Environmental Protection Agency (the “EPA”) issued an “endangerment and cause or contribute finding” for greenhouse gases under the federal Clean Air Act, which allowed the EPA to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Since 2009, the EPA has issued regulations that, among other things, require a reduction of emissions of greenhouse gases from motor vehicles and that impose greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources.

Additionally, in October 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas sources in the United States on an annual basis, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA expanded its greenhouse reporting rule to include onshore petroleum natural gas production, offshore petroleum and natural gas production, onshore natural gas processing, natural gas transmission, underground natural gas storage,

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liquefied natural gas storage, liquefied natural gas import and export, and natural gas distribution facilities. Under these rules, reporting of greenhouse gas emissions from such facilities is required on an annual basis.

These regulatory developments and legislative initiatives may curtail production and demand for fossil fuels such as oil and gas in areas of the world where our customers operate and thus adversely affect future demand for our services, which may in turn adversely affect our future results of operations. In addition, changes in environmental laws and regulations, or claims for damages to persons, property, natural resources or the environment, could result in substantial costs and liabilities, and thus there can be no assurance that we will not incur significant environmental compliance costs in the future. Such environmental liability could substantially reduce our net income and could have a significant impact on our financial ability to carry out our operations.

The application of the Jones Act (which regulates the kind of vessels that can carry goods between ports of the US) to offshore oil and gas work in the US is interpreted in large part by letter rulings of the U.S. Customs and Border Protection Agency (“CBP”). The cumulative effect of these letter rulings has been to establish a framework for offshore operators to understand when an operation can be carried out by a foreign flag vessel and when it must be carried out by a coastwise qualified US flag vessel. In early 2010, CBP and its parent agency, Department of Homeland Security (“DHS”), initiated a proposed rulemaking that would have been subject to public comment following publication in the Federal Register. The proposed rulemaking would have largely reversed the holdings of years of letter rulings from the CBP regarding the application of the Jones Act to offshore oil and gas work. The agencies subsequently withdrew the proposed rulemaking before it was published in the Federal Register. If DHS or CBP re-proposes a change to the application of the Jones Act similar to that originally proposed by CBP, and such proposal is adopted, or if CBP issues one or more letter rulings that interprets the Jones Act as being more restrictive to the operation of foreign flag vessels, such a development could potentially lead to operational delays or increased operating costs in instances where we would be required to hire coastwise qualified vessels that we currently do not own, in order to transport certain merchandise to projects on the OCS. This could increase our costs of compliance and doing business and make it more difficult to perform our offshore services in the US.

Economic downturn and lower oil and natural gas prices could negatively impact our business.

Our operations are affected by local, national and worldwide economic conditions and the condition of the oil and gas industry. Certain economic data indicates the global economy faces an uncertain outlook. The consequences of a prolonged period of little or no economic growth will likely result in a lower level of activity and increased uncertainty regarding the direction of energy prices and the capital and commodity markets, which will likely contribute to decreased offshore exploration and drilling. A lower level of offshore exploration and drilling could have a material adverse effect on the demand for our services. In addition, a general decline in the level of economic activity might result in lower commodity prices, which may also adversely affect our revenues from our service business. The extent of the impact of these factors on our results of operations and cash flows depends on the length and severity of the decreased demand for our services and lower commodity prices.

Continued market deterioration could also jeopardize the performance of certain counterparty obligations, including those of our insurers, customers and financial institutions. Although we assess the creditworthiness of our counterparties, prolonged business decline or disruptions as a result of economic slow-down or lower commodity prices could lead to changes in a counterparty’s liquidity and increase our exposure to credit risk and bad debts. In the event any such party fails to perform, our financial results could be adversely affected and we could incur losses and our liquidity could be negatively impacted.

Our contracting services operations are adversely affected by low oil and gas prices and by the cyclicality of the oil and gas industry.

Conditions in the oil and natural gas industry are subject to factors beyond our control. Our contracting services operations are substantially dependent upon the condition of the oil and gas industry, and in particular, the willingness of oil and gas companies to make capital expenditures for offshore exploration, development, drilling and production operations. The level of capital expenditures generally depends on the prevailing view of future oil and gas prices, which are influenced by numerous factors affecting the supply and demand for oil and gas, including, but not limited to:

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- worldwide economic activity;
- demand for oil and natural gas, especially in the United States, Europe, China and India;
- economic and political conditions in the Middle East and other oil-producing regions;
- actions taken by the Organization of Petroleum Exporting Countries ("OPEC");
- the availability and discovery rate of new oil and natural gas reserves in offshore areas;
- the cost of offshore exploration for and production and transportation of oil and gas;
- the ability of oil and natural gas companies to generate funds or otherwise obtain external capital for exploration, development and production operations;
- the sale and expiration dates of offshore leases in the United States and overseas;
- technological advances affecting energy exploration, production, transportation and consumption;
- weather conditions;
- environmental and other governmental regulations; and
- tax laws, regulations and policies.

A sustained period of low drilling and production activity or lower commodity prices would likely have a material adverse effect on our financial position, cash flows and results of operations.

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

We are constructing a newbuild semisubmersible well intervention vessel, the Q5000. Further, the Helix 534 drillship is currently undergoing upgrades and modifications to convert it into a well intervention vessel. We are also constructing additional ROVs and trenchers. We may also commence the construction of additional vessels for our fleet from time to time without first obtaining service contracts covering any such vessel. Our failure to secure service contracts for vessels under construction prior to deployment could adversely affect our financial position, results of operations and cash flows.

Depending on available opportunities, we may construct additional vessels for our fleet in the future. In addition, we incur significant upgrade, refurbishment and repair expenditures on our fleet from time to time. Some of these expenditures are unplanned. These projects are subject to risks of delay or cost overruns inherent in any large construction project resulting from numerous factors, including the following:

- shortages of equipment, materials or skilled labor;
- unscheduled delays in the delivery of ordered materials and equipment;
- unanticipated increases in the cost of equipment, labor and raw materials, particularly steel;
- weather interferences;
- difficulties in obtaining necessary permits or in meeting permit conditions;
- design and engineering problems;
- political, social and economic instability, war and civil disturbances;
- delays in customs clearance of critical parts or equipment;
- financial or other difficulties or failures at shipyards and suppliers;
- disputes with shipyards and suppliers; and
- work stoppages and other labor disputes.

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

Time chartering of our subsea services and subsea trenching and protection vessels require us to make payments regardless of utilization and revenue generation which could adversely affect our operations.

Many of our ROV support vessels are under time charter contracts. Should we not have work for such vessels, we are still required to make time charter payments and making such payments absent

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revenue generation could have an adverse effect on our financial position, results of operations and cash flows.

Our contracting business typically declines in winter, and bad weather in the Gulf of Mexico or North Sea can adversely affect our operations.

Marine operations conducted in the Gulf of Mexico and North Sea are seasonal and depend, in part, on weather conditions. Historically, we have enjoyed our highest vessel utilization rates during the summer and fall when weather conditions are favorable for offshore exploration, development and construction activities. We typically have experienced our lowest utilization rates in the first quarter. As is common in the industry, we may bear the risk of delays caused by some adverse weather conditions. Accordingly, our results in any one quarter are not necessarily indicative of annual results or continuing trends.

Certain areas in and near the Gulf of Mexico and North Sea experience unfavorable weather conditions including hurricanes and other extreme weather conditions on a relatively frequent basis. Substantially all of our facilities and assets offshore and along the Gulf of Mexico and the North Sea are susceptible to damage and/or total loss by these storms. Damage caused by high winds and turbulent seas could potentially cause us to curtail service operations for significant periods of time until damage can be assessed and repaired. Moreover, even if we do not experience direct damage from any of these storms, we may experience disruptions in our operations because customers may curtail their development activities due to damage to their platforms, pipelines and other related facilities.

Our current backlog for our contracting services operations may not be ultimately realized.

As of December 31, 2012, backlog for our contracting services operations which is supported by written agreements or contracts totaled $829.6 million, of which $554.4 million is expected to be performed in 2013. We may not be able to perform under these contracts due to events beyond our control, and our customers may seek to cancel or renegotiate our contracts for various reasons, including those described above. In addition, some of our customers could experience liquidity issues or could otherwise be unable or unwilling to perform under the contract, which could ultimately lead a customer to go into bankruptcy or to otherwise encourage a customer to seek to repudiate, cancel or renegotiate a contract. Our inability or the inability of our customers to perform under our or their contractual obligations may have a material adverse effect on our financial position, results of operations and cash flows.

The operation of marine vessels is risky, and we do not have insurance coverage for all risks.

Marine construction involves a high degree of operational risk. Hazards, such as vessels sinking, grounding, colliding and sustaining damage from severe weather conditions, are inherent in marine operations. These hazards can cause personal injury or loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage, and suspension of operations. Damage arising from such occurrences may result in lawsuits asserting large claims. Insurance may not be sufficient or effective under all circumstances or against all hazards to which we may be subject. A successful claim for which we are not fully insured could have a material adverse effect on us. Moreover, we cannot assure you that we will be able to maintain adequate insurance in the future at rates that we consider reasonable. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased substantially and could escalate further. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. For example, insurance carriers are now requiring broad exclusions for losses due to war risk and terrorist acts and limitations for wind storm damages. As a result, our revenues and profits are increasingly dependent on our larger vessels. The current insurance on our vessels, in some cases, is in amounts approximating book value, which could be less than replacement value. In the event of property loss due to a catastrophic marine disaster, mechanical failure, collision or other event, insurance may not cover a substantial loss of revenues, increased costs and other liabilities, and therefore, the loss of any of our large vessels could have a material adverse effect on us.

Our customers may be unable or unwilling to indemnify us.

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

Concerns regarding the European debt crisis and market perceptions concerning the instability of the euro, the potential re-introduction of individual currencies within the Eurozone, or the potential dissolution of the euro entirely, could adversely affect our business, results of operations and financing.

As a result of the debt crisis with respect to countries in Europe, in particular most recently in Greece, Italy, Ireland, Portugal and Spain, the European Commission created the European Financial Stability Facility (the "EFSF") and the European Financial Stability Mechanism (the "EFSM") to provide funding to countries using the euro as their currency (the "Eurozone") that are in financial difficulty and seek such support. In March 2011, the European Council agreed on the need for Eurozone countries to establish a permanent financial stability mechanism, the European Stability Mechanism (the "ESM"), which will be activated by mutual agreement, to assume the role of the EFSF and the EFSM in providing external financial assistance to Eurozone countries after June 2013. Despite these measures, concerns persist regarding the debt burden of certain Eurozone countries and their ability to meet future financial obligations, the overall stability of the euro and the suitability of the euro as a single currency given the diverse economic and political circumstances in individual Eurozone countries. These concerns could lead to the re-introduction of individual currencies in one or more Eurozone countries, or, in more extreme circumstances, the possible dissolution of the euro currency entirely. Should the euro dissolve entirely, the legal and contractual consequences for holders of euro-denominated obligations would be determined by laws in effect at such time. These potential developments, or market perceptions concerning these and related issues, could adversely affect the value of the Company's euro-denominated assets and obligations. In addition, concerns over the effect of this financial crisis on financial institutions in Europe and globally could have an adverse impact on the capital markets generally, and more specifically on the ability of the Company and its customers, suppliers and lenders to finance their respective businesses, to access liquidity at acceptable financing costs, if at all, on the availability of supplies and materials and on the demand for the Company's services.

Failure to comply with the U.S. Foreign Corrupt Practices Act or foreign anti-bribery legislation could have an adverse impact on our business.

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

Lack of access to the credit market could negatively impact our ability to operate our business and to execute our business strategy.

Access to financing may be limited and uncertain, especially in times of economic weakness and the revolving situation in Europe, regarding the sovereign debt crisis of many participant countries in the European Union. If the capital and credit markets are limited, we may incur increased costs associated with any additional financing we may require for future operations. Additionally, if the capital and credit markets are limited, it could potentially result in our customers curtailing their capital and operating expenditure programs, which could result in a decrease in demand for our vessels and a reduction in fees and/or utilization. In addition, certain of our customers could experience an inability to pay suppliers, including us, in the event they are unable to access the capital markets as needed to fund their business operations. Likewise, our suppliers may be unable to sustain their current level of operations, fulfill their commitments and/or fund future operations and obligations, each of which could adversely affect our operations. Continued lower levels of economic activity and weakness in the credit markets could also adversely affect our ability to implement our strategic objectives and dispose of non-core business assets.

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Our forward-looking statements assume that our lenders, insurers and other financial institutions will be able to fulfill their obligations under our various credit agreements, insurance policies and contracts. If any of our significant financial institutions were unable to perform under such agreements, and if we were unable to find suitable replacements at a reasonable cost, our results of operations, liquidity and cash flows could be adversely impacted.

Our indebtedness and the terms of our indebtedness could impair our financial condition and our ability to fulfill our debt obligations.

As of December 31, 2012, we had approximately $1.0 billion of consolidated indebtedness outstanding. Our total indebtedness was $729.1 million as of February 19, 2013 after the partial repayment of our Term Loans and borrowings under the Revolving Credit Facility following the sale of ERT. The level of indebtedness may have an adverse effect on our future operations, including:

- limiting our ability to obtain additional financing on satisfactory terms to fund our working capital requirements, capital expenditures, acquisitions, investments, debt service requirements and other general corporate requirements;
- increasing our vulnerability to a continued general economic downturn, competition and industry conditions, which could place us at a disadvantage compared to our competitors that are less leveraged;
- increasing our exposure to potential rising interest rates because a portion of our current and potential future borrowings are at variable interest rates;
- reducing the availability of our cash flows to fund our working capital requirements, capital expenditures, acquisitions, investments and other general corporate requirements because we will be required to use a substantial portion of our cash flows to service debt obligations;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- limiting our ability to expand our business through capital expenditures or pursuit of acquisition opportunities due to negative covenants in senior secured credit facilities that place annual and aggregate limitations on the types and amounts of investments that we may make, and limiting our ability to use proceeds from asset sales for purposes other than debt repayment (except in certain circumstances where proceeds may be reinvested under criteria set forth in our credit agreements).

A prolonged period of weak economic activity may make it increasingly difficult to comply with our covenants and other restrictions in agreements governing our debt. Our ability to comply with these covenants and other restrictions may be affected by the economic conditions and other events beyond our control. If we fail to comply with these covenants and other restrictions, it could lead to an event of default, the possible acceleration of our repayment of outstanding debt and the exercise of certain remedies by the lenders, including foreclosure on our pledged collateral.

Our operations outside of the United States subject us to additional risks.

Our operations outside of the United States are subject to risks inherent in foreign operations, including, without limitation:

- the loss of revenue, property and equipment from expropriation, nationalization, war, insurrection, acts of terrorism and other political risks;
- increases in taxes and governmental royalties;
-

changes in laws and regulations affecting our operations, including changes in customs, assessments and procedures, and changes in similar laws and regulations that may affect our ability to move our assets in and out of foreign jurisdictions;
- renegotiation or abrogation of contracts with governmental entities;
- changes in laws and policies governing operations of foreign-based companies;
- currency restrictions and exchange rate fluctuations;
- world economic cycles;
- restrictions or quotas on production and commodity sales;
- limited market access; and
- other uncertainties arising out of foreign government sovereignty over our international operations.

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In addition, laws and policies of the United States affecting foreign trade and taxation may also adversely affect our international operations.

Our consolidated financial results are reported in U.S. dollars while certain assets and other reported items are denominated in the currencies of other countries, creating currency translation risk.

The reporting currency for our consolidated financial statements is the U.S. dollar. Certain of our assets, liabilities, revenues and expenses are denominated in other countries' currencies. Those assets, liabilities, revenues and expenses are translated into U.S. dollars at the applicable exchange rates to prepare our consolidated financial statements. Therefore, increases or decreases in exchange rates between the U.S. dollar and those other currencies affect the value of those items as reflected in our consolidated financial statements, even if their value remains unchanged in their original currency. Substantial fluctuations in the value of the U.S. dollar could have a significant impact on our results.

We may not be able to compete successfully against current and future competitors.

The contracting services business in which we operate are highly competitive. Several of our competitors are substantially larger and have greater financial and other resources than we have. If other companies relocate or acquire vessels for operations in the Gulf of Mexico, North Sea, Asia Pacific or West Africa regions, levels of competition may increase and our business could be adversely affected.

In addition, in a few countries, the national oil companies have formed subsidiaries to provide oilfield services for them, competing with services provided by us. To the extent this practice expands, our business could be adversely impacted.

The loss of the services of one or more of our key employees, or our failure to attract and retain other highly qualified personnel in the future, could disrupt our operations and adversely affect our financial results.

Our industry has lost a significant number of experienced professionals over the years due to its cyclical nature, which is attributable, among other reasons, to the volatility in commodity prices. Our continued success depends on the active participation of our key employees. The loss of our key people could adversely affect our operations.

In addition, the delivery of our services requires personnel with specialized skills and experience. As a result, our ability to remain productive and profitable will depend upon our ability to employ and retain skilled workers. Our ability to expand our operations depends in part on our ability to increase the size of our skilled labor force. The demand for skilled workers in our industry is high, and the supply is limited. In addition, although our employees are not covered by a collective bargaining agreement, the marine services industry has in the past been targeted by maritime labor unions in an effort to organize Gulf of Mexico employees. A significant increase in the wages paid by competing employers or the unionization of our Gulf of Mexico employees could result in a reduction of our 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.

If we fail to effectively manage our growth strategy, our results of operations could be harmed.

Our current strategy is to expand our growing well intervention and robotics operations. We must plan and manage our growth effectively to achieve increased revenue and maintain profitability in our evolving market. If we fail to effectively manage current and future growth, our results of operations could be adversely affected. In the past, our growth has placed significant demands on our personnel, management and other resources. We must continue to improve our operational, financial, management and legal compliance information systems to keep pace with the planned expansion of our services.

Certain provisions of our corporate documents and Minnesota law may discourage a third party from making a takeover proposal.

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Our Articles of Incorporation give our Board of Directors the authority, without any action by our shareholders, to fix the rights and preferences on up to 4,994,000 shares of undesignated preferred stock, including dividend, liquidation and voting rights. In addition, our by-laws divide the Board of Directors into three classes. We are also subject to certain anti-takeover provisions of the Minnesota Business Corporation Act. We also have employment arrangements with all of our executive officers that require cash payments in the event of a "change of control." Any or all of the provisions or factors described above may discourage a takeover proposal or tender offer not approved by management and the Board of Directors and could result in shareholders who may wish to participate in such a proposal or tender offer receiving less for their shares than otherwise might be available in the event of a takeover attempt.

Other Risks

Other risk factors could cause actual results to be different from the results we expect. The market price for our common stock, as well as other companies in the oil and natural gas industry, has been historically volatile, which could restrict our access to capital markets in the future. Other risks and uncertainties may be detailed from time to time in our filings with the SEC.

Many of these risks are beyond our control. In addition, future trends for pricing, margins, revenue and profitability remain difficult to predict in the industries we serve and under current market, economic and political conditions. Forward-looking statements speak only as of the date they are made and, except as required by applicable law, we do not assume any responsibility to update or revise any of our forward-looking statements.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

OUR VESSELS

We own a fleet of seven vessels and 48 ROVs, four trenchers, and two ROVDrills. We also lease four vessels and one ROV. Currently all of our vessels, both owned and chartered, have DP capabilities specifically designed to respond to the deepwater market requirements. Our Seawell and Well Enhancer vessels have built-in saturation diving systems.

Listing of Vessels, Barges and ROVs Related to Contracting Services Operations (1)

	Flag State	Placed in Service (2)	Length (Feet)	Berths	SAT Diving	DP	Crane Capacity (tons)
CONTRACTING SERVICES:							
Pipelay —							
Caesar (3)	Vanuatu	5/2010	482	220	—	DP	300 and 36
Express (3)	Vanuatu	8/2005	531	132	—	DP	396 and 150
Floating Production Unit —							
Helix Producer I (4)	Bahamas	4/2009	528	95	—	DP	26 and 26
Well Intervention —							

Q4000 (5)	U.S.	4/2002	312	135	—	DP	160 and 360; 600 Derrick
Seawell	U.K.	7/2002	368	129	Capable	DP	130 and 65 Derrick
Well Enhancer	U.K.	10/2009	432	120	Capable	DP	100 and 150 Derrick
Helix 534 (6)	Panama	Pending	534	156	—	DP	600 Derrick
Robotics —							
49 ROVs, 4 Trenchers and 2 ROVDrills (3), (7), (8)	—	Various	—	—	—	—	—
Olympic Canyon (8)	Norway	4/2006	304	87	—	DP	150
Olympic Triton (8)	Norway	11/2007	311	87	—	DP	150
Deep Cygnus (8)	Panama	4/2010	400	92	—	DP	150 and 25
Grand Canyon (8)	Panama	10/2012	419	104	—	DP	250

(1) Under government regulations and our insurance policies, we are required to maintain our vessels in accordance with standards of seaworthiness and safety set by government regulations and classification organizations. We maintain our fleet to the standards for seaworthiness, safety and health set by the ABS, Bureau Veritas ("BV"), Det Norske Veritas ("DNV"), Lloyds Register of Shipping ("Lloyds"), and the USCG. ABS, BV, DNV and Lloyds are classification societies used by ship owners to certify that their vessels meet certain structural, mechanical and safety equipment standards.

(2) Represents the date we placed the vessel in service and not the date of commissioning.

(3) Subject to vessel mortgages (US ROVs and trenchers only) securing our Credit Agreement described in Note 7. Vessels are subject to a definitive sales agreement and are expected to be sold in 2013.

(4) Following the initial conversion of this vessel from a former ferry vessel into a DP floating production unit, additional topside production equipment was added to the vessel and it was certified for oil and natural gas processing work in June 2010 (see "Production Facilities"). The topside production equipment is subject to mortgages securing our Credit Agreement (Note 7).

(5) Subject to vessel mortgage securing our MARAD debt described in Note 7.

(6) Currently undergoing improvements and modifications in Singapore and expected to be placed in service in the third quarter of 2013 (Note 13).

(7) Average age of our fleet of ROVs, trenchers and ROVDrills is approximately 5.9 years.

(8) Leased. One ROV is leased; we own the remaining 48 ROVs.

The following table details the average utilization rate for our vessels by category (calculated by dividing the total number of days the vessels in this category generated revenues by the total number of calendar days in the applicable period) for the years ended December 31, 2012, 2011 and 2010:

	Year Ended December 31,		
	2012	2011	2010
Contracting Services:			
Pipelay and robotics support	90%	76%	84%
Well intervention	82%	90%	83%
ROVs	67%	60%	62%

We incur routine dry dock, inspection, maintenance and repair costs pursuant to Coast Guard regulations in order to maintain our vessels in class under the rules of the applicable class society. The reduced well intervention utilization in 2012 reflects the significant downtime associated with the regulatory dry docks for our Q4000, Seawell and Well Enhancer vessels. In addition to complying with these requirements, we have our own vessel maintenance program that we believe permits us to continue to provide our customers with well maintained, reliable vessels. In the normal course of business, we charter other vessels on a short-term basis, such as tugboats, cargo barges, utility boats and additional robotics support vessels.

PRODUCTION FACILITIES

We own a 50% interest in Deepwater Gateway, a limited liability company in which Enterprise Products Partners L.P. is the other member. Deepwater Gateway was formed to construct, install and own the Marco Polo TLP in order to process production from Anadarko Petroleum Corporation's Marco Polo field discovery at Green Canyon Block 608, which is located in water depths of 4,300 feet. Anadarko required processing capacity of 50,000 barrels of oil per day and 150 million cubic feet (Mmcf) of natural gas per day for its Marco Polo field. The Marco Polo TLP was designed to process 120,000 barrels of oil per day and 300 Mmcf of natural gas per day and payload with space for up to six subsea tiebacks.

We also own a 20% interest in Independence Hub, an affiliate of Enterprise Products Partners L.P., that owns the Independence Hub platform, a 105-foot deep draft, semi-submersible platform located in Mississippi Canyon Block 920 in a water depth of 8,000 feet that serves as a regional hub for natural gas production from multiple ultra-Deepwater fields in the eastern Gulf of Mexico. The Independence Hub facility is capable of processing up to one Bcf per day of gas. The facility's first processing began in July 2007.

Further, we, along with Kommandor Rømø, a Danish corporation, formed Kommandor LLC and converted a ferry vessel into the HP I, a dynamically positioned floating production vessel. The initial conversion of the HP I was completed in April 2009, and we have chartered the vessel from Kommandor LLC. We own approximately 81% of Kommandor LLC.

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After the initial conversion and our subsequent charter of the HP I, we installed, at 100% our cost, processing facilities and a disconnectable fluid transfer system on the vessel. The HP I is capable of processing up to 45,000 barrels of oil and 80 MMcf of natural gas daily. We had planned for the vessel to be initially used at the Phoenix field; however, in June 2010 as we approached reestablishment of production from the Phoenix field, the vessel was contracted to assist in the Macondo well control and containment efforts (Note 1). Following this work, the HP I returned to the Phoenix field, where production commenced in October 2010. The HP I is contracted for work in the Phoenix field through at least December 31, 2016. The results of Kommandor LLC and the HP I are consolidated within our Production Facilities business segment (Note 14).

SUMMARY OF OIL AND NATURAL GAS RESERVE DATA

As previously disclosed, we sold ERT on February 6, 2013. The below referenced information relates to ERT and is provided pursuant to authoritative SEC and other accounting rules and regulations because we owned ERT as of December 31, 2012. Because we had entered into definitive plan to sell ERT prior to that date, its operations and related assets and liabilities have been presented as discontinued operations for all periods presented in this Annual Report. See Note 16 for additional information regarding our estimates of proved reserves and future cash flows and discounted cash flows from proved reserves at December 31, 2012, 2011 and 2010.

Internal Controls Over Reserve Estimation Process

The reserve information in this Annual Report for the year ended December 31, 2012 is based on the estimates prepared by ERT’s Vice President — Reservoir Engineering and Business Development and his petroleum engineering staff, and it is the responsibility of management. The preparation of our oil and gas reserves is completed in accordance with our prescribed internal control policy and procedures. For the years ended December 31, 2011 and 2010, we engaged an independent reservoir engineering firm to prepare their own estimates of our proved reserves.

Our policies and procedures regarding internal controls over the recording of reserve estimates require proved reserves to be in compliance with the SEC definitions and guidance and prepared in accordance with generally accepted petroleum engineering principles. Some of the procedures conducted in the estimation of our proved reserves include the verification of data into reserve economic evaluation software, multiple reviews of reserve data generated by such software and detailed review of results of the proved reserves with the appropriate members of both ERT and the Company’s management. Responsibility for compliance in reserves bookings is delegated to ERT’s Vice President — Reservoir Engineering and Business Development.

ERT’s Vice President — Reservoir Engineering and Business Development is the technical person primarily responsible for overseeing the preparation of our proved reserve estimates. His estimates covered all of our former oil and gas properties. He is a Registered Professional Engineer in Louisiana and Texas. He has a B.S. degree in Civil Engineering and has been a Registered Professional Engineer for over 31 years and a member of the Society of Petroleum Engineers for over 37 years. He has over 37 years of industry experience with positions of increasing responsibility in engineering and reservoir evaluations.

We also employed experienced reserve engineers and geologists who assisted ERT’s Vice President — Reservoir Engineering and Business Development in the responsibility for determining proved reserves in conformance with SEC guidelines. Engineering reserve estimates were prepared by us based upon our interpretation of production performance data and sub-surface information derived from the drilling of existing wells. Information used to conduct this evaluation includes but is not limited to seismic data, well logs, production tests, reservoir pressures and well performance and test data. Our internal reservoir engineers analyzed 100% of our oil and gas fields on an annual basis (40 fields as of December 31, 2012).

The table below sets forth the approximate estimate of our proved reserves as of December 31, 2012. Proved reserves cannot be measured exactly because the estimation of reserves involves numerous judgmental determinations based on various assumptions, including assumptions required by the SEC as to oil and gas prices, drilling and operating expenses, capital expenditures, asset retirement costs, taxes and availability of funds. The process of estimating oil and gas reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic

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data for each reservoir. Accordingly, reserve estimates must be continually revised as a result of new information obtained from drilling and production history, new geological and geophysical data and changes in economic conditions. Actual quantities of reserves recovered will most likely vary from the estimates set forth below.

	Proved Developed Reserves	Proved Undeveloped Reserves	Total Proved Reserves
Gas (MMcf)	43,475	29,812	73,287
Oil (MBbls)	12,431	7,539	19,970
Total (MBOE)	19,677	12,507	32,184

Proved Undeveloped Reserves ("PUDs")

At December 31, 2012, our PUDs totaled 29.8 Bcf of natural gas and 7.5 MMBbls of crude oil for a total of 12.5 MMBOE. Our PUDs represent approximately 39% of our total estimates of proved oil and natural gas reserves at December 31, 2012. At December 31, 2011 our estimated PUD reserves totaled 16.1 MMBOE. All estimates of oil and natural gas reserves are inherently imprecise and subject to change as new technical information about the properties is obtained. Estimates of proved reserves for wells with little or no production history are less reliable than those based on a long production history. Subsequent evaluation of the same reserves may result in variations which may be substantial. This is especially valid as it pertains to PUD reserves.

We did not develop any PUD reserves in 2012. In 2011, we developed approximately 5.1 MMBOE of PUD reserves associated with four fields, including 0.9 MMBOE related to the Jake field that was sold in December 2011. In 2010, we developed approximate 0.7 MMBOE of PUD reserves at our Gunnison field.

Costs incurred to develop PUDs totaled $78.2 million in 2011 and $40.1 million in 2010. The estimated future development costs related to the development of PUDs were approximately $248.4 million at December 31, 2012.

For additional information regarding estimates of oil and gas reserves, including estimates of proved developed and proved undeveloped reserves, the standardized measure of discounted future net cash flows, and the changes in discounted future net cash flows, see Note 16.

United States Offshore

Deepwater

The proved reserves estimates associated with three fields in the Deepwater of the Gulf of Mexico totaled approximately 16.4 MMBOE or approximately 51% of our total estimated proved reserves at December 31, 2012. At that date, we operated both the Phoenix field and certain portions of the Bushwood field, representing approximately 89% of our Deepwater proved reserves. Gunnison, a non-operated field, has been producing since December 2003. In December 2011, we sold our ownership interest in the substantially developed Jake field at Green Canyon Block 490 for gross proceeds of approximately $31 million. Our net production from our Deepwater properties totaled approximately 4.5 MMBOE in 2012 as compared to 5.7 MMBOE in 2011.

Outer Continental Shelf

The estimated proved reserves for our 37 fields in the Gulf of Mexico on the OCS totaled approximately 15.8 MMBOE, or 49% of our total estimated proved reserves, as of December 31, 2012. Our net production from the

OCS properties totaled approximately 2.1 MMBOE in 2012 and 3.0 MMBOE in 2011. We were the operator of 91% of our OCS properties.

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United Kingdom Offshore

In December 2006, we acquired the Camelot field, located offshore in the North Sea, of which we subsequently sold a 50% interest in June 2007. In February 2010, we acquired our joint interest partner and as a result we own a 100% interest in the Camelot field (Note 3). The operating results of our U.K. Camelot field are reflected in continuing operations in the accompanying financial statements as the field did not meet the accounting requirements to be classified as an asset held for sale and thus qualify for discontinued operations treatment. However, during 2011, we commenced abandonment of the Camelot field in accordance with the then applicable U.K. regulations. We substantially completed these abandonment activities in 2012. In 2012, we recorded $15.5 million of expense charges to reflect an increase in our estimated costs to complete our abandonment activities at this non-producing field. In 2011, we recorded similar impairment charges totaling approximately $20.0 million to increase the field's then estimated asset retirement obligation following changes in certain U.K. regulations (Note 3). The estimated abandonment costs for the Camelot field totaled $42.8 million at December 31, 2012, of which we had incurred all but $2.9 million as of that date. Excluding these impairment charges, the results of our U.K. operations were immaterial for each of the three years ended December 31, 2012, 2011 and 2010, respectively.

Production, Price and Cost Data

Production, price and cost data for our former oil and gas operations in the United States are as follows:

	Year Ended December 31,		
	2012	2011	2010
Production:			
Gas (Bcf)	11	17	27
Oil (MMBbls)	5	6	3
Total (MBOE)	6,619	8,694	7,870
Average sales prices realized (including hedges):			
Gas (per Mcf) (1)	$ 5.22	$ 6.04	$ 6.01
Oil (per Bbl)	$ 104.26	$ 100.91	$ 75.27
Total (BOE)	$ 83.40	$ 79.26	$ 52.78
Average production cost per BOE	$ 24.89	$ 20.28	$ 16.66
Average depletion and amortization per BOE	$ 23.92	$ 25.29	$ 29.89

(1) Includes sales of natural gas liquids.

Productive Wells

The number of productive oil and gas wells in which we held interests as of December 31, 2012 is as follows:

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
United States — Offshore	211	166	178	90	389	256

Productive wells are producing wells and wells capable of production. The number of gross wells is the total number of wells in which we own a working interest. A net well is deemed to exist when the sum of fractional ownership working interests in gross wells equals one. The number of net wells is the sum of the fractional working interests owned in gross wells expressed as whole numbers and fractions thereof. One or more completions in the same borehole are counted as one well in this table.

The following table summarizes non-producing wells and wells with multiple completions as of December 31, 2012:

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	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Non-producing (shut-in)	97	72	137	70	234	142
Multiple completions	15	7	39	16	54	23

Developed and Undeveloped Acreage

The developed and undeveloped acreage (including both leases and concessions) that we held at December 31, 2012 is as follows:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
United States — Offshore	229,340	141,124	120,633	104,505

Developed acreage is acreage spaced or assignable to productive wells. A gross acre is an acre in which a working interest is owned. A net acre is deemed to exist when the sum of fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Undeveloped acreage is considered to be those leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves. Included within undeveloped acreage are those leased acres (held by production under the terms of a lease) that are not within the spacing unit containing, or acreage assigned to, the productive well holding such lease. The current terms of our leases on undeveloped acreage are scheduled to expire as shown in the table below (the terms of a lease may be extended by drilling and production operations):

	Offshore	
	Gross	Net
2013	36,520	30,760
2014	11,520	11,520
2015	5,760	5,760
2016	46,080	39,168
2017	9,233	9,233
2018 and beyond	11,520	8,064
Total	120,633	104,505

Drilling Activity

The following table shows the results of oil and gas wells drilled in the United States for each of the years ended December 31, 2012, 2011 and 2010:

	Net Exploratory Wells			Net Development Wells		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2012	1.2	—	1.2	—	—	—

Year ended December 31, 2011	—	—	—	—	—	—
Year ended December 31, 2010	—	—	—	1.0	—	1.0

No wells were drilled in the United Kingdom in 2012, 2011 or 2010. We did not have any wells in progress at December 31, 2012.

A productive well is an exploratory or development well that is not a dry hole. A dry hole is an exploratory or development well determined to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

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An exploratory well is a well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir. A development well, for purposes of the table above and as defined in the rules and regulations of the SEC, is a well drilled within the proved area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive. The number of wells drilled refers to the number of wells completed at any time during the respective year, regardless of when drilling was initiated. Completion refers to the installation of permanent equipment for the production of crude oil or natural gas, or in the case of a dry hole, to the reporting of abandonment to the appropriate agency. See Note 3, for additional information regarding our former oil and gas operations.

FACILITIES

Our corporate headquarters are currently located at 400 North Sam Houston Parkway East, Suite 400, Houston, Texas. In 2013, we plan to consolidate our corporate headquarters and U.S. based well intervention and robotics operating units into a new leased office building currently under construction. The address of this new corporate office will be 3505 West Sam Houston Parkway North, Houston, Texas 77043. We own the Aberdeen (Dyce), Scotland facility and our Spoolbase in Ingleside, Texas. All other facilities are leased. The list of our facilities as of December 31, 2012 is as follows:

Location	Function	Size
Houston, Texas	Helix Energy Solutions Group, Inc. Corporate Headquarters, Project Management, and Sales Office	92,274 square feet
	Helix Subsea Construction, Inc. Corporate Headquarters	
	Energy Resource Technology GOM, Inc. Corporate Headquarters	
	Helix Well Ops, Inc. Corporate Headquarters, Project Management, and Sales Office	
	Kommandor LLC Corporate Headquarters	
Houston, Texas	Canyon Offshore, Inc. Corporate, Management and Sales Office	1.0 acre (Building: 24,000 square feet)
Dallas, Texas	Energy Resource Technology GOM, Inc. Dallas Office	8,999 square feet
Ingleside, Texas	Helix Ingleside LLC Spoolbase	120 acres
Dulac, Louisiana	Energy Resource Technology GOM, Inc. Shore Base	20 acres 1,720 square feet
Aberdeen (Dyce), Scotland	Helix Well Ops (U.K.) Limited	3.9 acres

	Corporate Offices and Operations	(Building: 42,463 square feet)
	Canyon Offshore Limited Corporate Offices, Operations and Sales Office	
	Energy Resource Technology (U.K). Limited Corporate Offices	
Singapore	Canyon Offshore International Corp Corporate, Operations and Sales	22,486 square feet
	Helix Offshore Crewing Service Pte. Ltd. Corporate Headquarters	

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Item 3. Legal Proceedings

On July 8, 2011, a shareholder derivative lawsuit styled City of Sterling Heights Police & Fire Retirement System v. Owen Kratz, et al. was filed in the United States District Court for the Southern District of Texas, Houston Division. In the suit, the plaintiff makes claims against our Board of Directors, certain of our former directors, our top current and former executives and the independent compensation consultant to the Compensation Committee of our Board of Directors, for breaches of the fiduciary duty of loyalty, unjust enrichment and aiding and abetting the alleged breaches of fiduciary duty relating to the long-term equity awards granted in 2010 to certain of the Company's executive officers. The Company filed a motion to dismiss the claim asserting that the plaintiff has not (i) pled specific facts excusing its failure to make pre-suit demand on the Company's Board of Directors as required by Minnesota law; (ii) filed proper verification; or (iii) stated a claim. A ruling regarding the motion is pending.

On May 12, 2012, a shareholder derivative lawsuit styled Mark Lucas v. Owen Kratz, et al. was filed in the 270th Judicial District in the District Court of Harris County, Texas. In the suit, the plaintiff makes claims against our Board of Directors, certain of our former directors, certain of our current and former executive officers and the independent compensation consultant to the Compensation Committee of our Board of Directors, for breaches of the fiduciary duties of candor, good faith and loyalty, unjust enrichment and aiding and abetting the alleged breaches of fiduciary duty relating to the long-term equity awards granted in 2010 to certain of our executive officers. This case is essentially a "copycat" complaint asserting similar causes of action arising out of the same facts as set forth in the federal action described above. We have filed a motion to stay, motion to dismiss, special exceptions, plea to the jurisdiction and an original answer asserting that: (i) the suit should be stayed in favor of a first-filed federal derivative case; (ii) the plaintiff has not pled specific facts showing wrongful refusal of demand; (iii) the plaintiff has not demonstrated he continually owned shares during the complained of action; and (iv) the plaintiff has not stated a claim. The plaintiff is generally demanding disgorgement of the excessive compensation, restraint on the disposition/exercise of the alleged improperly awarded equity, implementation of additional internal controls, and attorney's fees and costs of litigation.

We have received value added tax (VAT) assessments from the State of Andhra Pradesh, India (the "State") in the amount of approximately $28 million for the tax years 2007, 2008, 2009, and 2010 related to an Indian subsea and diving contract that we entered into in December 2006. The State claims we owe unpaid taxes related to products consumed by us during the period of the contract. We are of the opinion that the State has arbitrarily assessed this VAT tax and has no foundation for the assessment and believe that we have complied with all rules and regulations as it relates to VAT in the State. We also believe that our position is supported by law and intend to vigorously defend our position. However, the ultimate outcome of this assessment and our potential liability from it, if any, cannot be determined at this time. If the current assessment is upheld, it may have a material negative effect on our consolidated results of operations while also impacting our financial position.

Item 4. Mine Safety Disclosures

Not applicable.

Executive Officers of the Company

The executive officers of Helix are as follows:

Name	Age	Position
Owen Kratz	58	President and Chief Executive Officer and Director
Anthony Tripodo	60	Executive Vice President and Chief Financial Officer
Clifford V. Chamblee	53	Executive Vice President and Chief Operating Officer

Alisa B. Johnson	55	Executive Vice President, General Counsel and Corporate Secretary
Lloyd A. Hajdik	47	Senior Vice President — Finance and Chief Accounting Officer

Owen Kratz is President and Chief Executive Officer of Helix. He was named Executive Chairman in October 2006 and served in that capacity until February 2008 when he resumed the position of President and Chief Executive Officer. He was appointed Chairman in May 1998 and served as the Company's Chief Executive Officer from April 1997 until October 2006. Mr. Kratz served as President from 1993 until February 1999, and has served as a Director since 1990. He served as Chief Operating Officer from 1990

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through 1997. Mr. Kratz joined Helix in 1984 and held various offshore positions, including saturation diving supervisor, and management responsibility for client relations, marketing and estimating. From 1982 to 1983, Mr. Kratz was the owner of an independent marine construction company operating in the Bay of Campeche. Prior to 1982, he was a superintendent for Santa Fe and various international diving companies, and a diver in the North Sea. Mr. Kratz has a Bachelor of Science degree from State University of New York (SUNY).

Anthony Tripodo was elected as Executive Vice President and Chief Financial Officer of Helix on June 25, 2008. Mr. Tripodo oversees the finance, treasury, accounting, tax, information technology and corporate planning functions. Mr. Tripodo was a director of Helix from February 2003 until June 2008. Prior to joining Helix, Mr. Tripodo was the Executive Vice President and Chief Financial Officer of Tesco Corporation. From 2003 through the end of 2006, he was a Managing Director of Arch Creek Advisors LLC, a Houston based investment banking firm. From 1997 to 2003, Mr. Tripodo was Executive Vice President of Veritas DGC, Inc., an international oilfield service company specializing in geophysical services, including serving as Executive Vice President, Chief Financial Officer and Treasurer of Veritas from 1997 to 2001. Previously, Mr. Tripodo served 16 years in various executive capacities with Baker Hughes, including serving as Chief Financial Officer of both the Baker Performance Chemicals and Baker Oil Tools divisions. Mr. Tripodo has served as a director of Geokinetics, Inc. since March 2010. He graduated Summa Cum Laude with a Bachelor of Arts degree from St. Thomas University (Miami).

Clifford V. Chamblee is Executive Vice President and Chief Operating Officer of Helix. He joined the Company in its robotics subsidiary, Canyon Offshore, Inc. (Canyon), in 1997. Mr. Chamblee served as President of Canyon from 2006 until 2011. Prior to becoming President of Canyon, Mr. Chamblee held several positions with increasing responsibilities at Canyon managing the operations of the company including as Senior Vice President and Vice President Operations from 1997 until 2006. Mr. Chamblee has been involved in the robotics industry for over 32 years. From 1988 to 1997, Mr. Chamblee held various positions with Sonsub International, Inc., including Vice President Remote Systems, Marketing Manager and Operations Manager. From 1986 until 1988, he was Operations Manager and Superintendent for Helix (then known as Cal Dive). From 1981 until 1986, Mr. Chamblee held various positions for Oceaneering International/Jered, including ROV Superintendent and ROV Supervisor. Prior to 1981, he was an ROV Technician for Martech International.

Alisa B. Johnson joined the Company as Senior Vice President, General Counsel and Secretary of Helix in September 2006, and in November 2008 became Executive Vice President, General Counsel and Secretary of the Company. Ms. Johnson oversees the legal, human resources and contracts and insurance functions. Ms. Johnson has been involved with the energy industry for over 22 years. Prior to joining Helix, Ms. Johnson worked for Dynegy Inc. for nine years, at which company she held various legal positions of increasing responsibility, including Senior Vice President and Group General Counsel — Generation. From 1990 to 1997, Ms. Johnson held various legal positions at Destec Entergy, Inc. Prior to that Ms. Johnson was in private law practice. Ms. Johnson received her Bachelor of Arts degree Cum Laude from Rice University and her law degree Cum Laude from the University of Houston.

Lloyd A. Hajdik joined the Company in December 2003 as Vice President — Corporate Controller. Mr. Hajdik became Chief Accounting Officer in February 2004 and in November 2008 he became Senior Vice President — Finance and Chief Accounting Officer. Prior to joining Helix, Mr. Hajdik served in a variety of accounting and finance-related roles of increasing responsibility with Houston-based companies, including NL Industries, Inc., Compaq Computer Corporation (now Hewlett Packard), Halliburton's Baroid Drilling Fluids and Zonal Isolation product service lines, Cliffs Drilling Company and Shell Oil Company. Mr. Hajdik was with Ernst & Young LLP in the audit practice from 1989 to 1995. Mr. Hajdik graduated Cum Laude from Texas State University receiving a Bachelor of Business Administration degree. Mr. Hajdik is a Certified Public Accountant and a member of the Texas Society of CPAs as well as the American Institute of Certified Public Accountants.

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PART II

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

Our common stock is traded on the New York Stock Exchange ("NYSE") under the symbol "HLX." The following table sets forth, for the periods indicated, the high and low sale prices per share of our common stock:

	Common Stock Prices	
	High	Low
2011		
First Quarter	$17.69	$10.92
Second Quarter	$19.20	$14.57
Third Quarter	$21.65	$12.65
Fourth Quarter	$19.42	$11.57
2012		
First Quarter	$19.98	$15.55
Second Quarter	$21.09	$14.90
Third Quarter	$20.81	$16.20
Fourth Quarter	$20.83	$15.54
2013		
First Quarter (1)	$25.49	$20.59

(1) Through February 19, 2013

On February 19, 2013, the closing sale price of our common stock on the NYSE was $24.67 per share. As of February 19, 2013, there were 341 registered shareholders and approximately 32,000 beneficial shareholders of our common stock.

We have never declared or paid cash dividends on our common stock and do not intend to pay cash dividends in the foreseeable future. We currently intend to retain earnings, if any, for the future operation and growth of our business. In addition, our financing arrangements prohibit the payment of cash dividends on our common stock. See Management's Discussion and Analysis of Financial Condition and Results of Operations "— Liquidity and Capital Resources."

Shareholder Return Performance Graph

The following graph compares the cumulative total shareholder return on our common stock for the period since December 31, 2007 to the cumulative total shareholder return for (i) the stocks of 500 large-cap corporations maintained by Standard & Poor's ("S&P 500"), assuming the reinvestment of dividends; (ii) the Philadelphia Oil Service Sector index ("OSX"), a price-weighted index of leading oil service companies, assuming the reinvestment of dividends; and (iii) a peer group selected by us (the "Peer Group") consisting of the following companies: Atwood Oceanics Inc., Dril-Quip, Inc., GulfMark Offshore, Inc., Hercules Offshore, Inc., Hornbeck Offshore Services, Inc., McDermott International, Inc., Oceaneering International, Inc., Oil States International, Inc., Rowan Companies, Inc., Superior Energy Services, Inc., TETRA Technologies, Inc., and Tidewater Inc. The returns of each member of the Peer Group have been weighted according to each individual company's equity market capitalization as of December 31, 2012 and have been adjusted for the reinvestment of any dividends. We believe that the members of the Peer Group provide services and products more comparable to us than those companies included in the OSX. The graph assumes $100 was invested on December 31, 2007 in our common stock at the closing price on that date price and on December 31, 2007 in the three indices presented. We paid no cash dividends during the period presented. The cumulative total percentage returns for the period presented are as follows: our stock — (50.3)%; the Peer Group — (31.6)%; the OSX — (27.0)%; and S&P 500 — 8.6%. These results are not necessarily indicative of future performance.

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Comparison of Five Year Cumulative Total Return among Helix, S&P 500, OSX and Peer Group

	As of December 31,					
	2007	2008	2009	2010	2011	2012
Helix	$ 100.0	$ 17.5	$ 28.3	$ 29.3	$ 38.1	$ 49.7
Peer Group Index	$ 100.0	$ 34.0	$ 60.7	$ 73.1	$ 68.7	$ 68.4
Oil Service Index	$ 100.0	$ 40.3	$ 64.6	$ 81.3	$ 71.7	$ 73.0
S&P 500	$ 100.0	$ 63.0	$ 79.7	$ 91.7	$ 93.6	$ 108.6

Source: Bloomberg

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased (1)	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced program (2)	(d) Maximum number of shares that may yet be purchased under the program (3)
October 1 to October 31, 2012	—	$ —	—	—
November 1 to November 30, 2012	—	—	—	—
December 1 to December 31, 2012	265	18.49	—	—
	265	$ 18.49	—	—

(1) Includes shares delivered to the Company by employees in satisfaction of minimum withholding taxes upon vesting of restricted shares.

(2) Shares repurchased under previously-announced stock buyback program (Note 11).

(3) Amount as of December 31, 2012. In January 2013, we issued approximately 0.1 million shares to certain of our employees. These grants will increase the number of shares available for repurchase by a corresponding amount (Note 9).

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Item 6. Selected Financial Data.

The financial data presented below for each of the five years ended December 31, 2012, should be read in conjunction with Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data included elsewhere in this Annual Report. In February 2013, we sold ERT. Accordingly, the results associated with our former Oil and Gas segment are presented as discontinued operations for all periods presented in this Annual Report.

	Year Ended December 31,				
	2012	2011	2010	2009 (1)	2008
Net revenues	$846,109	$702,000	$774,469	$1,077,312	$1,572,091
Gross profit	49,915	149,683	164,817	218,623	433,254
Operating income (loss) (2)	(68,483)	63,040	51,079	101,693	280,699
Equity in earnings of investments	8,434	22,215	19,469	32,329	31,854
Income (loss) from continuing operations	(66,803)	37,856	(17,496)	110,728	149,887
Income (loss) from discontinued operations, net of tax (3)	23,684	95,221	(106,657)	65,023	(739,944)
Net income (loss), including noncontrolling interests (4)	(43,119)	133,077	(124,153)	175,751	(590,057)
Net (income) loss applicable to noncontrolling interests	(3,178)	(3,098)	(2,835)	(19,697)	(45,873)
Net income (loss) applicable to Helix	(46,297)	129,979	(126,988)	156,054	(635,930)
Preferred stock dividends (5)	(37)	(40)	(114)	(54,187)	(3,192)
Net income (loss) applicable to Helix common shareholders	(46,334)	129,939	(127,102)	101,867	(639,122)
Adjusted EBITDA from continuing operations, less Cal Dive (6)	233,612	178,953	160,250	126,797	176,660
Adjusted EBITDAX (6)	$600,828	$668,662	$430,326	$490,092	$575,272
Basic earnings (loss) per share of common stock:					
Continuing operations	$(0.67)	$0.33	$(0.19)	$0.36	$1.11
Discontinued operations	0.23	0.90	(1.03)	0.65	(8.16)
Net income (loss) per common share	$(0.44)	$1.23	$(1.22)	$1.01	$(7.05)
Diluted earnings (loss) per share of common stock:					
Continuing operations	$(0.67)	$0.33	$(0.19)	$0.35	$1.11
Discontinued operations	0.23	0.90	(1.03)	0.62	(8.16)
Net income (loss) per common share	$(0.44)	$1.23	$(1.22)	$0.97	$(7.05)
Weighted average common shares outstanding:					
Basic	104,449	104,528	103,857	99,136	90,650
Diluted	104,449	104,953	103,857	105,720	90,650

(1)

Excludes the results of Cal Dive subsequent to June 10, 2009 following its deconsolidation from our consolidated financial statements (Notes 1 and 2).

(2) Amount in 2012 includes impairment charges of approximately $177.1 million, including $14.6 million for the Intrepid, $157.8 million for the Caesar and related mobile pipelay equipment, and $4.6 million for well intervention assets at our former operations in Australia (Note 2).

(3) Oil and gas property impairment charges and asset retirement obligation overruns totaled $144.3 million in 2012, including the $138.6 million charge to reduce the value of ERT's properties to their estimated fair value in connection with the announcement of the sale of ERT in December 2012, $112.6 million in 2011, $176.1 million in 2010, $120.6 million in 2009 and $920.0 million in 2008. Our oil and gas property impairment charges in the fourth quarter of 2008 totaled $896.9 million and included charges to reduce goodwill ($704.3 million) and certain oil and gas properties ($192.6 million) to their estimated fair value. Also includes exploration expenses

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totaling $3.3 million in 2012, $10.9 million in 2011, $8.3 million in 2010, $24.4 million in 2009 and $32.9 million in 2008.

(4) In 2009, we had $77.3 million of gains on the sale of Cal Dive common stock held by us.

(5) The amount in 2009 includes $53.4 million of beneficial conversion charges related to our convertible preferred stock.

(6) This is a non-GAAP financial measure. Amounts in 2009 and 2008 are less Cal Dive's results. See "Non-GAAP Financial Measures" below for an explanation of the definition and use of such measure as well as a reconciliation of these amounts to each year's respective reported income (loss) from continuing operations.

	December 31,				
	2012	2011	2010	2009 (1)	2008
Working capital	$351,061	$548,066	$373,057	$197,072	$287,225
Total assets (2)	3,386,580	3,582,347	3,592,020	3,779,533	5,067,066
Long-term debt (including current maturities)	1,019,228	1,155,321	1,357,932	1,360,739	2,027,226
Convertible preferred stock (3)	—	1,000	1,000	6,000	55,000
Total controlling interest shareholders' equity	1,393,385	1,421,403	1,260,604	1,405,257	1,191,149
Noncontrolling interests	26,029	28,138	25,040	22,205	322,627
Total equity	1,419,414	1,449,541	1,285,644	1,427,462	1,513,776

(1) Reflects deconsolidation of Cal Dive effective June 10, 2009 (Notes 1 and 2).

(2) Includes assets of discontinued oil and gas operations. Total assets at December 31, 2012 included $900.2 million from discontinued operations.

(3) In 2012, the holder of the convertible preferred stock redeemed the remaining $1 million of our convertible preferred stock into 0.4 million shares of our common stock. In 2010, the holder of the convertible preferred stock redeemed $5 million of our convertible preferred stock into 1.8 million shares of our common stock. In 2009, the holder of the convertible preferred stock redeemed $49 million of our convertible preferred stock into 12.8 million shares of our common stock (Note 2).

Non-GAAP Financial Measures

A non-GAAP financial measure is generally defined by the SEC as one that purports to measure historical or future performance, financial position, or cash flows, but excludes amounts that would not be so adjusted in the most comparable measures under generally accepted accounting principles ("GAAP"). We measure our operating performance based on EBITDA, a non-GAAP financial measure that is commonly used but is not a recognized accounting term under GAAP. We use EBITDA to monitor and facilitate the internal evaluation of the performance of our business operations, to facilitate external comparison of our business results to those of others in our industry, to analyze and evaluate financial and strategic planning decisions regarding future investments and acquisitions, to plan and evaluate operating budgets, and in certain cases, to report our results to the holders of our debt as required under our debt covenants. We believe our measure of EBITDA provides useful information to the public regarding our ability to service debt and fund capital expenditures and may help our investors understand our operating performance and compare our results to other companies that have different financing, capital and tax structures.

We define EBITDA as income (loss) from continuing operations plus income taxes, net interest expense and other and depreciation and amortization expense. We separately disclose our non-cash asset impairment charges, which, if not material, would be reflected as a component of our depreciation and amortization expense. Because such impairment charges are material for most of the periods presented, we have reported them as a separate line item in the accompanying consolidated statements of operations. Non-cash impairment charges related to goodwill are also added back if applicable. Loss on early extinguishment of long-term debt is considered equivalent to additional interest expense.

In our reconciliation of income (loss), including noncontrolling interests, we provide amounts as reflected in our accompanying consolidated financial statements unless otherwise footnoted. This means that such amounts are recorded at 100% even if we do not own 100% of all of our subsidiaries. Accordingly, to arrive at our measure of Adjusted EBITDA from continuing operations, when applicable, we deduct the noncontrolling interests related to the adjustment components of EBITDA and the gain or loss on the sale of assets.

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We also provide a further reconciliation to arrive at Adjusted EBITDA from continuing operations, less Cal Dive which represents our results from continuing operations without inclusion of our share of Cal Dive's operating results. We sold substantially all of our interest in Cal Dive in 2009. Lastly we provide a measure of Adjusted EBITDAX which combines our measure of Adjusted EBITDA from continuing operations, less Cal Dive and the measure of Adjusted EBIDAX from discontinued operations. Our discontinued operations primarily represent ERT which was sold in February 2013. We define Adjusted EBITDAX from discontinued operations as income (loss) from discontinued operations, net of tax (Note 3) plus income taxes, net interest expense and other, depreciation, depletion, amortization and accretion expense and exploration expenses.

Other companies may calculate their measures of EBITDA, Adjusted EBITDA and Adjusted EBITDAX differently than we do, which may limit their usefulness as comparative measures. Because EBITDA is not a financial measure calculated in accordance with GAAP, it should not be considered in isolation or as a substitute for net income (loss) attributable to common shareholders or cash flows from operations, but used as a supplement to these GAAP financial measures. The reconciliation of our net income (loss) from continuing operations to EBITDA from continuing operations, Adjusted EBITDA from continuing operations, Adjusted EBITDA from continuing operations, less Cal Dive and Adjusted EBITDAX is as follows:

	Year Ended December 31,				
	2012	2011	2010	2009	2008
Net income (loss) from continuing operations	$(66,803)	$37,856	$(17,496)	$110,728	$149,887
Adjustments:					
Income tax provision (benefit)	(59,158)	(36,806)	19,166	68,867	97,793
Net interest expense and other	48,785	71,288	66,638	31,770	64,873
Loss on extinguishment of long-term debt	17,127	2,354	—	—	—
Depreciation and amortization	97,201	91,188	81,878	95,960	110,180
Asset impairment charges (1)	177,135	17,127	23,060	1,305	—
EBITDA from continuing operations	214,287	183,007	173,246	308,630	422,733
Adjustments:					
Noncontrolling interest Cal Dive	—	—	—	(44,785)	(105,280)
Noncontrolling interest Kommandor LLC	(4,128)	(4,060)	(3,878)	(3,344)	102
Unrealized loss on commodity derivative contracts	9,977	—	—	—	—
(Gain) loss on sale of assets	13,476	6	(9,118)	(77,413)	(335)
ADJUSTED EBITDA from continuing operations	$233,612	$178,953	$160,250	$183,088	$317,220
ADJUSTED EBITDA from continuing operations	$233,612	$178,953	$160,250	$183,088	$317,220
Less Cal Dive, net of noncontrolling interests	—	—	—	(56,291)	(140,560)
ADJUSTED EBITDA from continuing operations, less Cal Dive	$233,612	$178,953	$160,250	$126,797	$176,660
ADJUSTED EBITDA from continuing operations, less Cal Dive	$233,612	$178,953	$160,250	$126,797	$176,660
ADJUSTED EBITDAX from discontinued operations (2)	367,216	489,709	270,076	363,295	398,612
ADJUSTED EBITDAX	$600,828	$668,662	$430,326	$490,092	$575,272

(1) Amount in 2012 includes impairment charges of $14.6 million for the Intrepid, $157.8 million for the Caesar and related mobile pipelay equipment, and $4.6 million for well intervention assets at our former operations in Australia (Note 2). Amount in 2011 includes a $6.6 million impairment charge related to our well intervention equipment in Australia and a $10.6 million other than temporary impairment loss on our equity investment in our Australian joint venture (Note 5). Amount in 2010 includes $16.7 million related to goodwill impairment of our Australian well intervention subsidiary ("WOSEA") and a $2.2 million other than temporary impairment associated with Cal Dive (Note 2).

(2) Amounts relate to ERT which was sold in February 2013 (Notes 1 and 3), and Helix RDS Limited, our former reservoir technology consulting company that we sold in April 2009.

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

The following management's discussion and analysis should be read in conjunction with our historical consolidated financial statements located in Item 8. "Financial Statements and Supplementary Data" of this Annual Report. Any reference to Notes in the following management's discussion and analysis refers to the Notes to Consolidated Financial Statements located in Item 8. "Financial Statements and Supplementary Data" of this Annual Report. The results of operations reported and summarized below are not necessarily indicative of future operating results. This discussion also contains forward-looking statements that reflect our current views with respect to future events and financial performance. Our actual results may differ materially from those anticipated in these forward-looking statements as a result of certain factors, such as those set forth under Item 1A. "Risk Factors" and located earlier in this Annual Report.

Executive Summary

Our Business

We are an international offshore energy company that provides specialty services to the offshore energy industry, with a focus on our growing well intervention and robotics operations. In February 2013, we completed the sale of ERT, our former wholly-owned subsidiary that conducted our oil and gas operations in the U.S., for $620 million plus contingent consideration in the form of overriding royalty interests in the Wang well and certain other future exploration prospects. We used $318.4 million of the sales proceeds to reduce our indebtedness under our Credit Agreement (Note 7) and we will use the remainder to continue to support the expansion of our well intervention and robotics operations.

Our Strategy

Over the past few years, we have improved our balance sheet and increased our liquidity through dispositions of non-core business assets as well as reductions in capital spending and the amount of our debt outstanding. With this goal substantially accomplished with the sale of ERT and the expected sales of our remaining pipelay vessels and related equipment, we are now positioned to expand and grow our core operations.

Our current focus is to expand our Contracting Services capabilities by growing our well intervention and robotics operations. We believe that focusing on these services will deliver higher long-term financial returns to us than the businesses and assets that we have chosen to monetize. We are making strategic investments that expand our service capabilities or add capacity to existing services in our key operating regions. We are strengthening our well intervention fleet by constructing a newbuild semisubmersible vessel, the Q5000, acquiring the Discoverer 534 drillship (renamed the Helix 534) which is currently undergoing upgrades and modifications in Singapore to render it suitable for use as a well intervention vessel, and chartering the Skandi Constructor for use in our North Sea and Canadian well intervention operations. In addition, we are expanding our robotics operations by acquiring additional remotely operated vehicles ("ROVs") and trenchers as well as taking delivery of a newbuild chartered ROV support vessel, the Grand Canyon. We also plan to charter two similar vessels, the Grand Canyon II and Grand Canyon III.

Economic Outlook and Industry Influences

Demand for our contracting services operations is primarily influenced by the condition of the oil and gas industry, and in particular, the willingness of oil and gas companies to make capital expenditures for offshore exploration, drilling and production operations. Generally, spending for our contracting services fluctuates directly with the direction of oil and natural gas prices. The performance of our operations is also largely dependent on the prevailing market prices for oil and natural gas, which are impacted by global economic conditions, hydrocarbon production and capacity, geopolitical issues, weather, and several other factors, including but not limited to:

- worldwide economic activity, including available access to global capital and capital markets;
- demand for oil and natural gas, especially in the United States, Europe, China and India;
- economic and political conditions in the Middle East and other oil-producing regions;
- the effect of regulations on offshore Gulf of Mexico oil and gas operations;
- actions taken by OPEC;
- the availability and discovery rate of new oil and natural gas reserves in offshore areas;

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- the cost of offshore exploration for and production and transportation of oil and gas;
- the ability of oil and natural gas companies to generate funds or otherwise obtain external capital for exploration, development and production operations;
- the sale and expiration dates of offshore leases in the United States and overseas;
- technological advances affecting energy exploration production transportation and consumption;
- weather conditions;
- environmental and other governmental regulations; and
- tax policies.

We believe that the long-term industry fundamentals are positive based on the following factors: (1) long-term increasing world demand for oil and natural gas emphasizing the need for continual replenishment of oil and gas production; (2) mature global production rates for offshore and subsea wells; (3) globalization of the natural gas market; (4) increasing number of mature and small reservoirs; (5) increasing offshore activity, particularly in deepwater; and (6) increasing number of subsea developments.

At December 31, 2012, we had cash on hand of $437.1 million and $487.6 million available for borrowing under our Revolving Credit Facility. Our capital expenditures for 2013 are expected to total approximately $350 million. If we successfully implement our business plan, we believe we have sufficient liquidity without incurring additional indebtedness beyond the existing capacity under the Revolving Credit Facility.

Business Activity Summary

Throughout the three year timespan of 2009 through 2011, we enhanced our financial position via the generation of approximately $600 million in pre-tax proceeds from dispositions of non-core business assets in order to strategically grow our core businesses. These dispositions included approximately $55 million from the sale of individual oil and gas properties, over $500 million from the sale of our stockholdings in Cal Dive and $25 million from the sale of our former reservoir consulting business.

In September 2012, we received $14.5 million from the sale of the Intrepid, one of our three subsea construction pipelay vessels. In October 2012, we entered into an agreement to sell our two remaining pipelay vessels, the Express and the Caesar, and other related pipelay equipment for $238.3 million, of which we have received a $50 million deposit that is only refundable in very limited circumstances. The final sale of these vessels will close and fund in two stages in 2013 following the completion of each vessel's existing backlog. Currently, we anticipate the Express sale will close in May 2013 and we expect the Caesar sale will close in July 2013. In February 2013, we sold ERT for $620 million plus contingent consideration in the form of overriding royalty interests in the Wang well and certain other future exploration prospects.

As we have shifted our focus towards growing our well intervention and robotics operations, we conducted the following activities in 2012 to expand our Contracting Services capabilities:

- we executed a contract with a shipyard in Singapore for the construction of a newbuild semisubmersible well intervention vessel, the Q5000, which is expected to be completed and placed in service in 2015;
- we contracted to charter the Skandi Constructor, which is expected to be utilized in our North Sea and Canadian well intervention operations starting in the first half of 2013;
- we acquired the Discoverer 534 drillship (renamed the Helix 534) which is currently undergoing upgrades and modifications in Singapore to render it suitable for use as a well intervention vessel and is expected to join our well intervention fleet in the Gulf of

Mexico in the third quarter of 2013;

- we took possession of a newbuild ROV support vessel, the Grand Canyon, which was commissioned specifically for our use under the terms of a long-term charter agreement; and
- we plan to charter two similar vessels, the Grand Canyon II and Grand Canyon III.

RESULTS OF OPERATIONS

We have disaggregated our contracting services operations into two reportable segments: Contracting Services and Production Facilities. Previously, we had a third business segment, Oil and Gas. In December 2012, we announced a definitive agreement for the sale of ERT. In February 2013, the sale of ERT closed. Accordingly, the results of ERT are presented as discontinued operations for all periods presented in this Annual Report.

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All material intercompany transactions between the segments have been eliminated in our consolidated financial statements, including our consolidated results of operations.

Contracting Services Operations

We seek to provide services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. The Contracting Services segment includes well intervention, robotics and subsea construction operations (see "Business Activities" above regarding the planned dispositions of our subsea construction vessels). Our Contracting Services business operates primarily in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions, with services that cover the lifecycle of an offshore oil or gas field. In addition, our robotics operations are often contracted for the development of renewable energy projects (wind farms). As of December 31, 2012, our Contracting Services segment had backlog of approximately $810.1 million, including $534.9 million expected to be performed in 2013. Our Production Facilities segment reflects the results associated with the operations of the HP I as well as our equity investments in two Gulf of Mexico production facilities (Note 5). Backlog for the HP I totaled approximately $19.5 million at December 31, 2012. However, in connection with the sale of ERT, a new fee arrangement for usage of the HP I at the Phoenix field was agreed upon with the new owner of ERT. Under the terms of this arrangement, ERT will pay us a lower fixed annual demand fee; however, ERT will also pay us a variable throughput fee. We currently anticipate that the total combined fees will approximate the previous fixed annual demand fee. The revised terms now also provide that the HP I will continue to provide service to ERT's Phoenix field through at least December 31, 2016. At December 31, 2011, our combined backlog for both Contracting Services and the HP I totaled $539.7 million. Backlog contracts are cancelable without penalty in many cases. Backlog is not necessarily a reliable indicator of total annual revenue for our contracting services operations as contracts may be added, cancelled and in many cases modified while in progress.

Discontinued Operations

In February 2013, we sold ERT for $620 million plus contingent consideration in the form of overriding royalty interests in the Wang well and certain other future exploration prospects. As a result, we have presented the assets and liabilities included in the sale of ERT and the historical operating results of our former Oil and Gas segment as discontinued operations in the accompanying consolidated financial statements (Notes 1 and 3). For additional information regarding the operating results of our former Oil and Gas segment, see section titled "Discontinued Operations — Oil and Gas" elsewhere in Item 7.

Comparison of Years Ended December 31, 2012 and 2011

The following table details various financial and operational highlights for the periods presented:

	Year Ended December 31, 2012	2011	Increase/ (Decrease)
Revenues (in thousands) —			
Contracting Services	$899,793	$738,235	$161,558
Production Facilities	80,091	75,460	4,631
Intercompany elimination	(133,775)	(111,695)	(22,080)
	$846,109	$702,000	$144,109
Gross profit (in thousands) —			
Contracting Services	$36,522	$137,444	$(100,922)
Production Facilities	40,645	39,170	1,475
Corporate and other	(19,374)	(27,024)	7,650

Intercompany elimination	(7,878)	93	(7,971)
	$49,915	$149,683	$(99,768)
Gross Margin —			
Contracting Services	4%	19%	
Production Facilities	51%	52%	
Total company	6%	21%	

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	Year Ended December 31, 2012	2011
Number of vessels (1) / Utilization (2)		
Contracting Services:		
Construction vessels	6/90 %	8/76 %
Well intervention	3/82 %	3/90 %
ROVs	55/67 %	46/60 %

(1) Represents number of vessels as of the end of the period excluding acquired vessels prior to their in-service dates, vessels taken out of service prior to their disposition and vessels jointly owned with a third party.

(2) Average vessel utilization rate is calculated by dividing the total number of days the vessels in this category generated revenues by the total number of calendar days in the applicable period. Utilization statistics for construction vessels excluded the Intrepid in the second half of 2012 as this asset had been in cold-stack mode during the third quarter and was sold in September 2012.

Intercompany segment revenues during the years ended December 31, 2012 and 2011 are as follows (in thousands):

	Year Ended December 31, 2012	2011	Increase/ (Decrease)
Contracting Services	$87,718	$65,638	$22,080
Production Facilities	46,057	46,057	—
	$133,775	$111,695	$22,080

Intercompany segment profit during the years ended December 31, 2012 and 2011 is as follows (in thousands):

	Year Ended December 31, 2012	2011	Increase/ (Decrease)
Contracting Services	$8,053	$104	$7,949
Production Facilities	(175)	(197)	22
	$7,878	$(93)	$7,971

In the following disclosures regarding our results of operations, please refer to the tables above and Note 14 for supplemental information regarding our business segment results. Our disclosures specifically refer to our Contracting Services and Production Facilities segments. Disclosures regarding our former Oil and Gas segment are presented under "Discontinued Operations — Oil and Gas" below and in Note 3.

Revenues. Our Contracting Services revenues increased by 22% in 2012 as compared to 2011 reflecting significantly higher utilization for our subsea construction vessels, which benefited from an increase in activity in the Gulf of Mexico in the first quarter of 2012, the continued deployment of the Caesar on an accommodation project in Mexico, and the Express working offshore Israel and in the North Sea for most of the second and third quarters of 2012. The variance also includes an increase in our robotics revenues reflecting the high utilization of our chartered vessels and owned ROVs, the utilization of a number of additional spot market vessels for much of 2012, and the performance of a number of North Sea trenching projects in early 2012 (which activities are not normally conducted during the first quarter in large part because of seasonal weather patterns). We achieved a slight increase in our well intervention activities despite the Q4000 (70 days), Seawell (52 days) and Well Enhancer (52 days) all being in regulatory dry dock in 2012. The lost days associated with the regulatory dry docks were more than offset by increasing rates reflecting the high demand for our well intervention services and vessels.

Our Production Facilities revenues increased by 6% in 2012 as compared to 2011, which primarily reflects the inclusion of the quarterly HFRS retainer fee, which commenced on April 1, 2011.

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Gross Profit. Our Contracting Services gross profit decreased by 73% in 2012 as compared to 2011. This decrease was primarily attributed to asset impairment charges of $157.8 million for the Caesar and related mobile pipelay equipment, $14.6 million for the Intrepid, and $4.6 million for well intervention assets associated with our former operations in Australia (Note 2). Gross profit was also negatively impacted in 2012 because of the lost utilization of our Q4000, Seawell and Well Enhancer well intervention vessels as a result of the extended regulatory dry docks. The decrease in gross profit was offset in part by the high margins achieved on many of our subsea construction projects in 2012.

Loss on Sale of Assets, Net. The $13.5 million loss on the disposition of assets in 2012 reflects the sale of the Intrepid in September 2012 (Note 2).

Non-hedge Loss on Commodity Derivative Contracts. The $10.5 million loss on commodity derivative contracts primarily reflects the amount of mark-to-market loss of unsettled oil and gas commodity derivative contracts associated with de-designation of these contracts as hedging instruments following the announcement in December 2012 of the sale of ERT (Note 3).

Selling, General and Administrative Expenses. Our selling, general and administrative expenses increased by $7.8 million in 2012 as compared to 2011. The increase is associated with higher long-term incentive compensation, which primarily reflects the fact that amortization of awards granted in 2012 vest over a period of three years (as compared to a five-year vesting period for all long-term incentive awards granted prior to 2012) (Note 9). Additionally, the 2012 amount includes approximately $3.5 million of severance and other closure costs associated with our decision to sell our remaining pipelay assets, to cease our Australian well intervention operations and to terminate the remaining lease term and other related closure costs associated with our previous office in Rotterdam, the Netherlands. Lastly, our 2012 amount also includes $2.6 million drawn against a letter of credit related to an international well abandonment project which was completed in 2011. We are seeking return of this amount but collection is not reasonably assured. Our selling, general and administrative expenses in 2011 included $1.6 million of severance costs related to the resignation of our former Executive Vice President and Chief Operating Officer.

As a percentage to revenues, our selling, general and administrative expenses were higher than our previously-reported amounts due to previously-allocated corporate shared services costs related to ERT being included in the results of our continuing operations. Under the applicable accounting guidance, such allocations are not permitted to be excluded from our selling, general and administrative expenses when a former business is presented as discontinued operations. The amount of corporate shared services that were previously allocated to ERT totaled $14.9 million in 2012, $18.5 million in 2011 and $10.7 million in 2010.

Equity in Earnings of Investments. Equity in earnings of investments decreased by $13.8 million in 2012 as compared to 2011. The decrease was primarily due to Independence Hub receiving lower fees from major customers of the facility following expiration of a five-year supplemental monthly demand fee in March 2012 and lower throughput at both the Deepwater Gateway and Independence Hub facilities, reflecting both storm-related disruptions and normal production declines of the fields using the facilities.

Net Interest Expense. Our net interest expense totaled $48.2 million in 2012 as compared to $70.2 million in 2011. The decrease in interest expense primarily reflects a $275 million reduction of our Senior Unsecured Notes indebtedness, including the early extinguishment of $75 million in the third quarter of 2011 and $200 million in the first quarter of 2012. The Senior Unsecured Notes bear a 9.5% interest rate which is greater than the 5.4% weighted average interest rate of our total indebtedness as of December 31, 2012. Capitalized interest totaled $4.9 million in 2012 as compared to $1.3 million in 2011. Generally, our capitalized interest will be increasing as we progress the construction of the Q5000 and the upgrades and modifications of the Helix 534. Interest income totaled $0.5 million in 2012 as compared with $1.4 million in 2011.

Loss on Early Extinguishment of Long-term Debt. The charges of $17.1 million in 2012 were associated with the early extinguishment of portions of our debt in the first quarter of 2012, including $11.5 million related to our repurchase of $200 million of our Senior Unsecured Notes and $5.6 million related to our repurchase of $142.2 million of our 2025 Notes (Note 7). The $2.4 million of charges in 2011 were related to premiums we paid to repurchase approximately $75 million of our Senior Unsecured Notes during the third quarter of 2011.

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Other Expense, Net. We reported net other expenses of $0.6 million in 2012 as compared to $1.1 million in 2011. These amounts primarily reflect foreign exchange fluctuations in our non U.S. dollar functional currencies. We recorded foreign exchange losses of approximately $0.1 million in 2012 as compared to $1.9 million in 2011. The foreign exchange losses were attributed to the strengthening of the U.S. dollar against other global currencies. Included in these foreign exchange gains or losses were $0.4 million and $0.2 million of gains related to our foreign exchange forward contracts in 2012 and 2011, respectively (Note 17). In 2012, we recorded a $0.6 million loss associated with the de-designation of our interest rate swaps. In 2011, we also sold our remaining 0.5 million shares of Cal Dive common stock for net proceeds of approximately $3.6 million. Our gain on the sale of these remaining Cal Dive common shares was approximately $0.8 million.

Income Tax Benefit. Income taxes reflected a benefit of $59.2 million in 2012 as compared to $36.8 million in 2011. The variance primarily reflects decreased profitability in the current year period. A 47.0% tax benefit was recorded for 2012, which was less favorable than the tax benefit that was recorded for 2011. The favorable effective tax rate for 2011 reflects the $31.3 million net tax benefit derived from the reorganization of our Australian well intervention operations.

Comparison of Years Ended December 31, 2011 and 2010

The following table details various financial and operational highlights for the periods presented:

	Year Ended December 31, 2011	2010	Increase/ (Decrease)
Revenues (in thousands) —			
Contracting Services	$738,235	$780,339	$(42,104)
Production Facilities	75,460	117,300	(41,840)
Intercompany elimination	(111,695)	(123,170)	11,475
	$702,000	$774,469	$(72,469)
Gross profit (in thousands) —			
Contracting Services	$137,444	$132,723	$4,721
Production Facilities	39,170	64,203	(25,033)
Corporate and other	(27,024)	(12,997)	(14,027)
Intercompany elimination	93	(19,112)	19,205
	$149,683	$164,817	$(15,134)
Gross Margin —			
Contracting Services	19%	17%	
Production Facilities	52%	55%	
Total company	21%	21%	
Number of vessels (1) / Utilization (2)			
Contracting Services:			
Construction vessels	8/76%	7/74%	
Well intervention	3/90%	4/83%	
ROVs	46/60%	46/62%	

(1) Represents number of vessels as of the end of the period excluding acquired vessels prior to their in-service dates, vessels taken out of service prior to their disposition and vessels jointly owned with a third party. At December

31, 2010, our well intervention vessels count included one vessel chartered by us from our Australian joint venture company (Note 5).

(2) Average vessel utilization rate is calculated by dividing the total number of days the vessels in this category generated revenues by the total number of calendar days in the applicable period.

Intercompany segment revenues during the years ended December 31, 2011 and 2010 are as follows (in thousands):

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	Year Ended December 31, 2011	2010	Increase/ (Decrease)
Contracting Services	$65,638	$109,012	$(43,374)
Production Facilities	46,057	14,158	31,899
	$111,695	$123,170	$(11,475)

Intercompany segment profit during the years ended December 31, 2011 and 2010 are as follows (in thousands):

	Year Ended December 31, 2011	2010	Increase/ (Decrease)
Contracting Services	$104	$15,655	$(15,551)
Production Facilities	(197)	3,457	(3,654)
	$(93)	$19,112	$(19,205)

Revenues. Our Contracting Services revenues decreased 5% in 2011 as compared to 2010 reflecting the decreased subsea construction activity in the Gulf of Mexico, primarily attributable to delays in permitting of projects since the Macondo well control incident in April 2010 as well as the decreased amount of internal vessel utilization in 2011 to develop our own oil and gas properties. The decrease in the utilization rates for our pipelay and robotics support vessels primarily reflects a lower number of projects with approved permits in the Gulf of Mexico region. Demand for our well intervention vessels remained strong in both the Gulf of Mexico and North Sea regions. Our Q4000, Express and HP I vessels were extensively involved in the Macondo well control and containment efforts in the second and third quarters of 2010.

Our Production Facilities revenues decreased 36% in 2011, reflecting a full year's utilization of the HP I at the Phoenix field (owned at the time 70% by us) as compared to utilization by a third party in the Macondo well control and containment efforts from June 2010 to October 2010 and subsequently at the Phoenix field for the remainder of 2010. Our revenues also include the quarterly retainer fees related to the HFRS, which commenced April 1, 2011.

Gross Profit. For 2011, our Contracting Services gross profit increased by 4% over the amounts earned in 2010 primarily reflecting strong demand and utilization for our well intervention services. These increases were partially offset by the weak subsea construction industry conditions in the Gulf of Mexico, which contributed to our lower pipelay and robotics support vessel and ROV utilization rates. Our contracting services rates in 2010 benefited from our increased scope of internal work related to ERT as well as the Express and Q4000 both being contracted to participate in the Macondo well control and containment efforts.

The decrease in our Production Facilities gross profit in 2011, as compared to 2010, reflects full utilization of the HP I in 2011 at the Phoenix field as opposed to approximately five months of third party utilization in 2010 during the Macondo well control and containment efforts.

Gain on Sale of Assets, Net. The $9.1 million gain in 2010 was attributed to $3.1 million from the sale of unused equipment relating to our Contracting Services and $6.0 million associated with the acquisition of the 50% working interest held by our former co-owner in the Camelot field in the United Kingdom (Note 3).

Selling, General and Administrative Expenses. Selling, general and administrative expenses totaled $86.6 million in 2011, which was $19.5 million lower than expenses incurred in 2010. The decrease primarily reflects a $17.5 million charge in 2010 related to settlement of litigation in Australia involving the termination of an international construction contract within our Contracting Services segment. In 2010, we also recorded a $4.1 million bad debt expense charge within our Contracting Services segment, including one $4.0 million allowance for a doubtful account reserve related to a separate international construction contract.

Equity in Earnings of Investments. Equity in earnings of investments increased by $2.7 million in 2011 as compared to 2010. This increase was mostly due to our Australian joint venture having equity

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earnings of $2.1 million in 2011 associated with project work in China while in the 2010 period the joint venture incurred $3.6 million of losses related primarily to its start-up costs (Note 5). Our equity in earnings also reflects lower throughput at Deepwater Gateway and Independence Hub reflecting lower production from the fields that are serviced by the respective facilities, including the storm-related disruptions in early September 2011.

Other Than Temporary Impairment Loss. In December 2011, the co-owner of the Australian joint venture sold its ownership interest in the joint venture to a third party. In light of uncertainties regarding the future commitment and term of the joint venture, we conducted an impairment assessment of our investment in the Australian joint venture. We concluded that the investment was fully impaired and we recorded a $10.6 million other than temporary impairment charge (Note 5). The $2.2 million other than temporary impairment charge in 2010 was associated with our remaining investment in Cal Dive (Note 2).

Net Interest Expense. We reported net interest expense of $70.2 million in 2011 as compared to $65.6 million in 2010. Capitalized interest decreased to $1.3 million in 2011 as compared to $12.5 million in 2010 reflecting the completion of major capital projects, including the conversions of the Caesar and HP I, which were placed in service in the second quarter of 2010, and the development of the Phoenix field, which commenced production in October 2010. The decrease in capitalized interest was offset by lower interest rates and lower levels of debt since year end 2010. Interest income increased to $1.4 million in 2011 from $0.5 million in 2010, reflecting our substantially higher cash balances.

Loss on Early Extinguishment of Long-term Debt. The $2.4 million of charges in 2011 were related to premiums we paid to repurchase approximately $75 million of our Senior Unsecured Notes during the third quarter of 2011.

Other Expense, Net. Net other expenses totaled $1.1 million in 2011 as compared to $1.0 million for 2010. The decrease in other expense primarily reflects a gain of $0.8 million on the sale of our remaining Cal Dive common stock in 2011. Also included in other income (expense) are foreign exchange fluctuations in our non U.S. dollar functional currencies and foreign exchange currency contracts. The strengthening of the U.S. dollar against other global currencies resulted in our recording foreign exchange losses totaling $1.9 million in 2011 as compared to $1.0 million in 2010.

Income Tax Provision (Benefit). An income tax benefit of $36.8 million was recorded in 2011 compared to an income tax provision of $19.2 million in 2010. The variance primarily reflects decreased profitability in 2011. The favorable effective tax rate for 2011 reflects the increased benefit derived from the effect of lower tax rates in certain foreign jurisdictions and the $31.3 million net tax benefit derived from the reorganization of our Australian well intervention operations. The unfavorable effective tax rate for 2010 reflects the non-deductible goodwill impairment, decreased benefit derived from the effect of lower tax rates in certain foreign jurisdictions and an increase in valuation allowance on certain non-U.S. deferred tax assets.

Discontinued Operations — Oil and Gas

Comparison of Years Ended December 31, 2012 and 2011

The following table details various financial and operational highlights related to our former Oil and Gas segment for the periods presented:

	Year Ended December 31, 2012	2011	Increase/ (Decrease)
Oil and Gas information —			
Oil production volume (MBbls)	4,725	5,785	(1,060)

Oil sales revenue (in thousands)	$492,678	$583,725	$(91,047)
Average oil sales price per Bbl (excluding hedges)	$106.11	$106.42	$(0.31)
Average realized oil price per Bbl (including hedges)	$104.26	$100.91	$3.35
Increase (decrease) in oil sales revenue due to:			
Change in prices (in thousands)	$19,418		
Change in production volume (in thousands)	(110,465)		
Total decrease in oil sales revenue (in thousands)	$(91,047)		

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	Year Ended December 31, 2012	2011	Increase/ (Decrease)
Gas production volume (MMcf)	11,361	17,458	(6,097)
Gas sales revenue (in thousands)	$59,341	$105,404	$(46,063)
Average gas sales price per mcf (excluding hedges)	$4.17	$5.45	$(1.28)
Average realized gas price per mcf (including hedges)	$5.22	$6.04	$(0.82)
Decrease in gas sales revenue due to:			
Change in prices (in thousands)	$(14,216)		
Change in production volume (in thousands)	(31,847)		
Total decrease in gas sales revenue (in thousands)	$(46,063)		
Total production (MBOE)	6,619	8,694	(2,075)
Price per BOE	$83.40	$79.26	$4.14
Oil and Gas revenue information (in thousands) —			
Oil and gas sales revenue	$552,019	$689,129	$(137,110)
Other revenues (1)	5,212	7,478	(2,266)
	$557,231	$696,607	$(139,376)

(1) Other revenues included fees earned under our process handling agreements.

The following table highlights certain relevant expense items in total (in thousands) and on a cost per barrel of production basis (natural gas converted to barrel of oil equivalent at a ratio of six Mcf of natural gas to each barrel of oil):

	Year Ended December 31, 2012 Total	2012 Per barrel	2011 Total	2011 Per barrel
Oil and Gas operating expenses (1):				
Direct operating expenses (2)	$117,451	$17.75	$128,037	$14.73
Workover	20,950	3.17	16,534	1.90
Transportation	6,737	1.02	8,589	0.99
Repairs and maintenance	8,553	1.29	11,842	1.36
Overhead and company labor	10,972	1.66	11,267	1.30
	$164,663	$24.89	$176,269	$20.28
Depletion expense	$145,734	$22.02	$205,035	$23.58
Abandonment	12,417	1.88	22,516	2.59
Accretion expense	12,550	1.90	14,880	1.71
Net hurricane (reimbursements) costs	662	0.10	(4,838)	(0.55)
Impairment	138,628	20.94	90,923	10.45
	309,991	46.84	328,516	37.78
Total	$474,654	$71.73	$504,785	$58.06

(1) Excludes exploration expenses of $3.3 million and $10.9 million for the years ended December 31, 2012 and 2011, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

All of our oil and gas operations were located in the U.S. Gulf of Mexico as of December 31, 2012. Previously, we had one property located offshore of the United Kingdom ("U.K."). In 2012, we substantially completed the abandonment of this oil and gas property in accordance with the applicable U.K. regulations (Note 3). We had no revenue associated with our U.K. oil and gas property during the three-year period ended December 31, 2012. The total operating costs associated with our U.K. oil and gas property totaled \$0.7 million, \$4.0 million and \$3.7 million in 2012, 2011 and 2010, respectively. The results of our U.K. property are reflected as continuing operations in the accompanying consolidated financial statements.

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Revenues. Oil and Gas revenues decreased 20% in 2012 as compared to 2011, reflecting lower production volumes offset in part by higher oil prices (inclusive of hedges). Our production decreased by 24% in 2012 as compared to 2011, primarily reflecting much lower natural gas production, normal oil production declines, and the weather-related downtime affecting (i) all of our fields in August 2012 associated with Hurricane Isaac and (ii) certain of our fields in June 2012. The decrease in the production of natural gas primarily reflects the disposition of certain oil and gas properties during 2012, most notably the sale of eight natural gas producing fields in the Main Pass area in January 2012.

Operating Expenses. Oil and Gas operating expenses decreased by 6% in 2012 as compared to 2011, primarily reflecting lower direct production costs and depletion expense as a result of lower production volumes as discussed in "Revenues" above. In addition, we recorded an impairment charge of $138.6 million associated with the announcement of the sale of ERT in 2012 as compared to a total of $90.9 million of producing property impairments in 2011. Oil and Gas operating expenses were also affected by $12.4 million of abandonment expense charges associated with non-producing fields in 2012 as compared to $22.5 million in 2011 (Note 3).

(Gain) Loss on Sale of Oil and Gas Properties. The $1.7 million loss in 2012 primarily related to the disposition of eight of our former non-operated oil and gas properties located in the Main Pass area of the Gulf of Mexico in January 2012. The $4.5 million gain in 2011 was associated with the sale of our interest in the Jake field at Green Canyon Block 490 for approximately $31 million in pre-tax gross proceeds in December 2011.

Non-hedge Gain on Commodity Derivative Contracts. The $5.6 million gain on commodity derivative contracts in 2012 primarily reflects gains from settled natural gas commodity derivative contracts that were previously de-designated as hedging instruments prior to the announcement of the sale of ERT.

Comparison of Years Ended December 31, 2011 and 2010

The following table details various financial and operational highlights related to our former Oil and Gas segment for the periods presented:

	Year Ended December 31,		Increase/
	2011	2010	(Decrease)
Oil and Gas information —			
Oil production volume (MBbls)	5,785	3,354	2,431
Oil sales revenue (in thousands)	$583,725	$252,445	$331,280
Average oil sales price per Bbl (excluding hedges)	$106.42	$78.46	$27.96
Average realized oil price per Bbl (including hedges)	$100.91	$75.27	$25.64
Increase in oil sales revenue due to:			
Change in prices (in thousands)	$85,998		
Change in production volume (in thousands)	245,282		
Total increase in oil sales revenue (in thousands)	$331,280		
Gas production volume (MMcf)	17,458	27,097	(9,639)
Gas sales revenue (in thousands)	$105,404	$162,919	$(57,515)
Average gas sales price per mcf (excluding hedges)	$5.45	$4.67	$0.78
Average realized gas price per mcf (including hedges)	$6.04	$6.01	$0.03
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$687		
Change in production volume (in thousands)	(58,202)		
Total decrease in gas sales revenue (in thousands)	$(57,515)		

Total production (MBOE)	8,694	7,870	824
Price per BOE	$79.26	$52.78	$26.48
Oil and Gas revenue information (in thousands) —			
Oil and gas sales revenue	$689,129	$415,364	$273,765
Other revenues (1)	7,478	10,005	(2,527)
	$696,607	$425,369	$271,238

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(1) Other revenues included fees earned under our process handling agreements.

The following table highlights certain relevant expense items in total (in thousands) and on a cost per barrel of production basis (natural gas converted to barrel of oil equivalent at a ratio of six Mcf of natural gas to each barrel of oil):

	Year Ended December 31,			
	2011		2010	
	Total	Per barrel	Total	Per barrel
Oil and Gas operating expenses (1):				
Direct operating expenses (2)	$128,037	$14.73	$84,178	$10.70
Workover (3)	16,534	1.90	23,156	2.94
Transportation	8,589	0.99	6,924	0.88
Repairs and maintenance	11,842	1.36	7,751	0.98
Overhead and company labor	11,267	1.30	9,147	1.16
	$176,269	$20.28	$131,156	$16.66
Depletion expense	$205,035	$23.58	$219,726	$27.92
Abandonment	22,516	2.59	4,542	0.58
Accretion expense	14,880	1.71	15,517	1.97
Net hurricane (reimbursements) costs	(4,838)	(0.55)	4,699	0.60
Impairment	90,923	10.45	172,596	21.93
	328,516	37.78	417,080	53.00
Total	$504,785	$58.06	$548,236	$69.66

(1) Excludes exploration expenses of $10.9 million and $8.3 million for the years ended December 31, 2011 and 2010, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

(3) Excludes all hurricane-related costs and changes resulting from Hurricane Ike in September 2008. Amounts in 2010 primarily reflect efforts to resolve production issues at both the Bushwood and East Cameron Block 346 fields.

Revenues. Oil and Gas revenues increased 64% in 2011, as compared to 2010, reflecting increased oil production and higher oil prices (inclusive of hedges). Our production increased by 824 MBOE, as compared to 2010. Our production for 2011 benefited from a full year of oil production from the Phoenix field that commenced production in October 2010. This increased oil production was partially offset by an approximate 36% decrease in our natural gas production, which primarily reflects decreased production from the Bushwood field located at Garden Banks Blocks 462, 463, 506 and 507.

Operating Expenses. Oil and Gas operating expenses decreased by 8% in 2011 as compared to 2010, primarily reflecting impairment charges totaling $90.9 million in 2011 as compared to $172.6 million in 2010 (Note 3) and lower depletion expense as a result of lower overall depletion rate. The decrease was partially offset by higher direct production costs associated with increased oil production as well as $22.5 million of abandonment expense charges associated with non-producing fields in 2011 as compared to $4.5 million in 2010.

Gain on Sale of Oil and Gas Properties. The $4.5 million gain in 2011 was associated with the sale of our interest in the Jake field at Green Canyon Block 490 for approximately $31 million in pre-tax gross proceeds in December 2011.

Non-hedge Gain on Commodity Derivative Contracts. The $1.1 million gain on commodity derivative contracts in 2010 primarily reflects the amount of mark-to-market gain associated with de-designation of our natural gas commodity derivative contracts as hedging instruments.

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LIQUIDITY AND CAPITAL RESOURCES

Overview

The following table presents certain information useful in the analysis of our financial condition and liquidity as of December 31, 2012 and 2011 (in thousands):

	2012	2011
Net working capital	$351,061	$548,066
Long-term debt (1)	$1,002,621	$1,147,444
Liquidity (2)	$924,688	$1,105,063

(1) Long-term debt does not include the current maturities portion of the long-term debt as such amount is included in net working capital. It is also net of unamortized debt discount on our 2025 Notes at December 31, 2011 and 2032 Notes at December 31, 2012. We repaid $318.4 million of our outstanding indebtedness in February 2013 following the sale of ERT (see table below). See Note 7 for disclosures related to our existing debt.

(2) Liquidity, as defined by us, is equal to cash and cash equivalents plus available capacity under our Revolving Credit Facility, which capacity is reduced by current letters of credit drawn against the facility. The reduction in our liquidity reflects capital expenditures to expand our well intervention fleet as well as payments to reduce our existing debt and to fund other capital expenditures (see "Outlook" below). As of December 31, 2012, our liquidity included cash and cash equivalents of $437.1 million and $487.6 million of available borrowing capacity under our Revolving Credit Facility (Note 7). As of December 31, 2011, our liquidity included cash and cash equivalents of $546.5 million and $558.6 million of available borrowing capacity under our Revolving Credit Facility.

The carrying amount of our debt, including current maturities, as of December 31, 2012 and 2011 is as follows (in thousands):

	Pro Forma (1)	2012	2011
Term Loans (mature July 2015) (2)	$ —	$367,181	$279,750
Revolving Credit Facility (matures July 2015) (2)	—	100,000	—
2025 Notes (mature December 2025) (3)	—	3,487	290,445
2032 Notes (mature March 2032) (4)	168,312	168,312	—
Senior Unsecured Notes (mature January 2016)	274,960	274,960	474,960
MARAD Debt (matures February 2027)	105,288	105,288	110,166
Total debt	$548,560	$1,019,228	$1,155,321

(1) This pro forma information illustrates the effect that certain unscheduled repayments of debt would have had on our debt outstanding at December 31, 2012 assuming they were physically made prior to December 31, 2012. Following the sale of ERT, in February 2013, we repaid $293.9 million of our Term Loans and $24.5 million under our Revolving Credit Facility with the after-tax proceeds from the sale. We will also make unscheduled payments to further reduce our existing debt with the after-tax proceeds from the sales of our remaining pipelay vessels and related equipment in 2013 and cash flow generated from operations.

(2) Represents earliest date debt would mature; see Note 7 for conditions that could extend the maturity date.

(3) The 2011 amount is net of the unamortized debt discount of $9.6 million. Substantially all the Notes were redeemed by the holders on December 15, 2012 (Note 7). We repurchased the remainder of the Notes in February 2013 (see (1) above).

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(4) This amount is net of the unamortized debt discount of $31.7 million. The notes will increase to the $200 million face amount through accretion of non-cash interest charges through March 2018, which is the period in which the holders of the notes may first require us to redeem the notes.

The following table provides summary data from our consolidated statements of cash flows (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Cash provided by (used in):			
Operating activities	$176,068	$182,658	$71,372
Investing activities	$(295,712)	$(95,300)	$(106,870)
Financing activities	$(145,232)	$(229,895)	$(29,279)
Discontinued operations (1)	$156,373	$297,481	$185,396

(1) Represents total cash flows associated with the operations of ERT. ERT was sold in February 2013. Other cash flows in the table above reflect our continuing operations.

Our current requirements for cash primarily reflect the need to fund capital expenditures to allow the growth of our current lines of business and to service our existing debt. We will further reduce our existing debt following the closing of the sales of our remaining pipelay vessels and related equipment in 2013. We may also repay debt with any additional free cash flow from operations. Historically, we have funded our capital program, including acquisitions, with cash flows from operations, borrowings under credit facilities and use of project financing along with other debt and equity alternatives.

We remain focused on maintaining a strong balance sheet and adequate liquidity. We have a reasonable basis for estimating our future cash flows supported by our existing and expanding backlog. We believe that internally generated cash flows and available borrowing capacity under our Revolving Credit Facility will be sufficient to fund our operations over at least the next twelve months.

In accordance with our Credit Agreement, Senior Unsecured Notes, 2025 Notes, 2032 Notes and MARAD debt, we are required to comply with certain covenants and restrictions, including certain financial ratios such as collateral coverage, interest coverage and consolidated indebtedness leverage, as well as the maintenance of minimum net worth, working capital and debt-to-equity requirements. Our Credit Agreement and Senior Unsecured Notes also contain provisions that limit our ability to incur certain types of additional indebtedness. These provisions effectively prohibit us from incurring any additional secured indebtedness or indebtedness guaranteed by the Company. The Credit Agreement does permit us to incur certain unsecured indebtedness, and also provides for our subsidiaries to incur project financing indebtedness (such as our MARAD loan) secured by the underlying asset, provided that such indebtedness is not guaranteed by us. Upon the occurrence of certain dispositions or the issuance or incurrence of certain types of indebtedness, we may be required to prepay a portion of the Term Loan debt and borrowings under the Revolving Credit Facility equal to the amount of proceeds received from such occurrences (in the event of a disposition of assets comprising collateral, 60% of the after-tax proceeds). Such prepayments will be applied first to the Term Loan B, and any excess will then be applied to the Term Loan A (see below) and the Revolving Credit Facility on a pro rata basis. As of December 31, 2012 and 2011, we were in compliance with all of our debt covenants and restrictions. In February 2013, we repaid $293.9 million of our Term Loans, including all of Term Loan B and $23.0 million of Term Loan A, and $24.5 million under our Revolving Credit Facility with the after-tax proceeds from the sale of ERT.

A prolonged period of weak economic activity may make it difficult to comply with our covenants and other restrictions in agreements governing our debt. Our ability to comply with these covenants and other restrictions is affected by economic conditions and other events beyond our control. If we fail to comply with these covenants and other restrictions, such failure could lead to an event of default, the possible acceleration of our repayment of outstanding debt and the exercise of certain remedies by the lenders, including foreclosure on our pledged collateral.

Our 2032 Notes can be converted prior to their stated maturity under certain triggering events specified in the respective indentures governing each series of such notes. Beginning in March 2018, the holders of the 2032 Notes may require us to repurchase these notes or we may at our own option elect to

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repurchase notes. To the extent we do not have cash on hand or long-term financing secured to cover the conversion, the 2032 Notes would be classified as current liabilities in our consolidated balance sheet. No conversion triggers were met during the years ended December 31, 2012. As of the date of this filing, there are no outstanding 2025 Notes. The repayment of this debt occurred when holders of $154.3 million of the 2025 Notes exercised their option on December 15, 2012 to require us to repurchase their 2025 Notes and we repurchased the remaining 2025 Notes in February 2013.

In June 2011, we amended our Credit Agreement to, among other things, extend its maturity to at least July 1, 2015 and increase the availability under our Revolving Credit Facility to $600 million. In February 2012, we entered into another amendment to our Credit Agreement. Under terms of this amendment, the lenders provided us with $100 million in additional proceeds under a term loan (Term Loan A). The terms of the Term Loan A are the same as those governing the Revolving Credit Facility, with the Term Loan A requiring a $5 million annual payment of the principal balance. The Term Loan A funded in late March 2012 and we used these proceeds and $100 million of borrowings under our Revolving Credit Facility to redeem $200 million of our Senior Unsecured Notes outstanding. In September 2012, we amended our Credit Agreement to (i) permit investments in certain non-guarantor, non-pledged subsidiaries and joint ventures, (ii) increase the debt basket for certain foreign subsidiaries from $200 million to $400 million, and (iii) remove EBITDA, interest charges and indebtedness related to certain secured assets from the calculation of financial covenants. See Note 7 for additional information related to our long-term debt, including more information regarding the recent amendments to our Credit Agreement and our requirements and obligations under the debt agreements including our covenants and collateral security.

Working Capital

Total cash flows from operating activities decreased by $114.7 million in 2012 as compared to 2011 primarily reflecting decreased oil and natural gas production, a substantial increase in costs incurred in performing oil and gas asset retirement projects and the effect of some of our vessels being in extended regulatory dry dock in 2012. These decreases were partially offset by an increased level of contracting services activity and the higher oil prices realized during 2012.

Total cash flows from operating activities increased by $235.7 million in 2011 as compared to 2010 primarily reflecting the effect of increased oil production as well as the substantially higher oil prices in 2011 as compared to 2010.

Investing Activities

Capital expenditures have consisted principally of the purchase or construction of dynamically positioned vessels, improvements and modifications to existing vessels, acquisition, exploration and development of oil and gas properties and investments in our production facilities. Significant sources (uses) of cash associated with investing activities for the years ended December 31, 2012 and 2011 are as follows (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Capital expenditures:			
Contracting Services	$(322,216)	$(69,259)	$(65,949)
Production Facilities	(823)	(30,896)	(56,269)
Distributions from equity investments, net (1)	7,797	1,266	2,286
Proceeds from sale of assets (2)	19,530	—	6,042
Proceeds from insurance reimbursement	—	—	7,020
Proceeds from sale of Cal Dive common stock	—	3,588	—

Net cash used in investing activities - continuing operations	(295,712)	(95,301)	(106,870)
Oil and Gas capital expenditures	(125,423)	(119,614)	(84,554)
Proceeds from sale of assets	—	31,000	852
Proceeds from insurance reimbursement	—	—	9,086
Other	5,366	1,598	(70)
Net cash used in investing activities - discontinued operations	(120,057)	(87,016)	(74,686)
Net cash used in investing activities	$(415,769)	$(182,317)	$(181,556)

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(1) Distributions from equity investments are net of undistributed equity earnings from our equity investments. Gross distributions from our equity investments are detailed in "Equity Investments" below.

(2) Proceeds from sale of assets reflect cash received from the sale of the Intrepid in September 2012 and the sale of certain equipment associated with our former Australian well intervention operations.

Capital expenditures associated with our contracting services business primarily include our Q5000 payments (see below), the payments in connection with the acquisition and subsequent upgrades and modifications of the Helix 534 (see below), and the costs incurred in the construction of additional ROVs and trenchers related to our robotics operations.

In March 2012, we executed a contract with a shipyard in Singapore for the construction of a newbuild semisubmersible well intervention vessel, the Q5000. This $386.5 million shipyard contract represents the majority of the expected costs associated with the construction of the Q5000. Under the terms of this contract, payments are made in a fixed percentage of the contract price, together with any variations, on contractually scheduled dates. At December 31, 2012, our total investment in the Q5000 was $139.6 million, including $115.9 million of scheduled payments made to the shipyard in 2012. We plan to spend approximately $140 million on the Q5000 in 2013, including scheduled shipyard payments of $115.9 million. The vessel is expected to be completed and placed in service in 2015.

In August 2012, we acquired the Discoverer 534 drillship from a subsidiary of Transocean Ltd. for $85 million. The vessel, renamed the Helix 534, is currently undergoing upgrades and modifications in Singapore to render it suitable for use as a well intervention vessel. At December 31, 2012, our investment in the acquisition and subsequent upgrades and modifications of the Helix 534 totaled $113.5 million. We estimate that an additional $50 million will be invested before the vessel is ready to be placed in service. The vessel is expected to join our well intervention fleet in the Gulf of Mexico in the third quarter of 2013.

Net cash used in discontinued operations relates to capital expenditures associated with ERT. These capital expenditures included costs associated with the exploration and development activities at the Danny II prospect within the Bushwood field at Garden Banks Block 506. Oil and Gas capital expenditures also included costs associated with ongoing exploration and subsequent development activities related to the Wang well that commenced drilling in the fourth quarter of 2012 and the T-6 well that, prior to the sale of ERT, we expected to drill in 2013. Both of these wells are located within the Phoenix field at Green Canyon Block 237.

Restricted Cash

As of December 31, 2012 and 2011, we had $28.4 million and $33.7 million of restricted cash, respectively, all of which consisted of funds required to be escrowed to cover the future asset retirement obligations associated with the South Marsh Island Block 130 field. These escrowed funds were included in the sale of ERT in February 2013. These amounts are reflected in "Non-current assets of discontinued operations" in the accompanying consolidated balance sheets.

Outlook

We anticipate that our capital expenditures in 2013 will total approximately $350 million. These estimates may increase or decrease based on various economic factors and/or existence of additional investment opportunities. However, we may reduce the level of our planned future capital expenditures given any prolonged economic downturn. We believe that internally-generated cash flows, cash from future sales of our non-core business assets, and availability under our existing credit facilities will provide the capital necessary to fund our 2013 initiatives.

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual cash obligations as of December 31, 2012 and the scheduled years in which the obligations are contractually due (in thousands):

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	Total (1)	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
2025 Notes (2)	$3,487	$3,487	$—	$—	$—
2032 Notes (3)	200,000	—	—	—	200,000
Senior Unsecured Notes	274,960	—	—	274,960	—
Term Loans (4)	367,181	8,000	359,181	—	—
MARAD debt	105,288	5,120	11,020	12,148	77,000
Revolving Credit Facility (5)	100,000	—	100,000	—	—
Interest related to debt	195,514	34,307	27,452	21,310	112,445
Property and equipment (6)	326,514	171,929	154,585	—	—
Operating leases (7)	399,483	86,357	180,794	104,649	27,683
Total cash obligations	$1,972,427	$309,200	$833,032	$413,067	$417,128

(1) Excludes unsecured letters of credit outstanding at December 31, 2012 totaling $12.4 million. These letters of credit primarily guarantee asset retirement obligations as well as various contract bidding, insurance activities and shipyard commitments.

(2) On December 15, 2012, holders of $154.3 million of the 2025 Notes exercised their option to require us to repurchase their 2025 Notes. We repurchased the remainder of the Notes in February 2013.

(3) Contractual maturity in 2032. The 2032 Notes can be converted prior to their stated maturity if the closing price of Helix's common stock for at least 20 days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter exceeds 130% of its issuance price on that 30th trading day (i.e., $32.53 per share). At December 31, 2012, the conversion trigger was not met. The first date that the holders of these notes may require us to redeem the notes is in March 2018. See Note 7 for additional information regarding these 2032 Notes.

(4) Our Term Loans will mature on July 1, 2015 but may extend to July 1, 2016 (January 1, 2016 with regards to Term Loan A) if our Senior Unsecured Notes are either refinanced or repaid in full by July 1, 2015 (Note 7). We repaid $293.9 million of our Term Loans in February 2013 following the sale of ERT.

(5) Our Revolving Credit Facility will mature on July 1, 2015 but may extend to January 1, 2016 if our Senior Unsecured Notes are either refinanced or repaid in full by July 1, 2015 (Note 7). We repaid $24.5 million under our Revolving Credit Facility in February 2013 following the sale of ERT.

(6) Primarily reflects the costs related to construction of our new semi-submersible well intervention vessel, the Q5000, and expected costs associated with the upgrades and modifications to render the Helix 534 suitable for use as a well intervention vessel.

(7) Operating leases included facility leases and vessel charter leases. At December 31, 2012, our vessel charter and ROV lease commitments totaled approximately $590.0 million.

Contingencies

Under terms of the ERT equity purchase agreement, we have required the buyer to provide bonding in a sufficient amount as determined by the BOEM to replace and allow for a full discharge of our existing guaranty to the BOEM for ERT's lease obligations. The BOEM is in the process of reevaluating its decommissioning assessments for lease properties in the Gulf of Mexico and as such it is currently uncertain as to the amount of bonding that will be required, and thus also the amount of collateral that the buyer will be required to post to its surety/ies to secure such bonding. To the extent that the purchaser is required to post bonding collateral in an amount greater than $100 million to obtain bonds in the aggregate amount required by the BOEM in order for the BOEM to release our guaranty of ERT's lease obligations, we have agreed to provide incremental collateral above that amount, if and to the extent required, to the surety/ies providing bonding for the deepwater properties (the Bushwood and Phoenix fields) in the form of letter(s) of credit, up to the next $50 million of required collateral, for a period not to exceed one year from issuance of the letter(s) of credit, after which the purchaser would then be required to provide all collateral associated with the bonding requirements with respect to our former oil and gas properties. As the BOEM conducts its review of the Gulf of Mexico decommissioning assessments, we intend to work closely with the purchaser to provide specific information regarding our former lease properties. We anticipate that the BOEM will determine its assessments of decommissioning costs for our former deepwater fields in the near term and that the bonding amounts, and therefore the bonding collateral requirements, to obtain a release of our guaranty with respect to ERT's lease obligations will be known. At the time of this filing it is uncertain whether the amount of collateral will exceed the $100 million threshold so as to require any incremental bonding collateral on our part.

Whenever we have a contract that qualifies as a loss contract, we estimate the future shortfall between our anticipated future revenues and future costs. In March 2009, we were notified of a third party's intention to terminate an international construction contract based on a claimed breach of that contract by one of our subsidiaries. Under the terms of the contract, our potential liability for damages was generally capped at approximately $32 million Australian dollars ("AUD"). We asserted counterclaims that in the aggregate approximated $12 million U.S. dollars. On March 30, 2010, an out of court settlement of these claims was reached. Pursuant to the settlement agreement, in April 2010 we paid the third party $15 million AUD to settle all of its damage claims against us. We also agreed not to seek any further payment of our counter claims against them. Our accompanying consolidated statement of operations for the year ended December 31, 2010 includes approximately $17.5 million in expenses associated with this settlement agreement, including $13.8 million for the litigation settlement payment and $3.7 million to write off our remaining trade receivable from the third party. The charges were recorded as a component of our selling, general and administrative expenses within our Contracting Services segment.

In 2010, we had two additional contracts that resulted in significant losses. The first of these contracts represented the initial project performed by the Caesar. The project, which included a primary work scope of laying 36-miles of pipe in the Gulf of Mexico, was completed in the third quarter of 2010 at a total loss of $12.0 million. The loss was primarily the result of certain start-up performance issues with the vessel as well as non-reimbursable costs associated with weather delays. The second contract was entered into by WOSEA and pertained to plugging, abandoning and salvage of subsea wells in an oil and gas field located offshore China. The project commenced in the second half of 2010 and was initially expected to be completed by the end of October 2010. However, the subsea wells were structurally difficult to plug and WOSEA also experienced some start-up issues with its recently repaired subsea intervention device, which was significantly damaged in March 2009. In the fourth quarter of 2010, WOSEA experienced significant weather delays resulting from the peak of typhoon season in the China Sea, which added non reimbursable time and related costs to the project. As a result of the continued weather delays, it was mutually agreed that WOSEA would discontinue the project and in connection with that decision, the parties also agreed to a reduced scope of work for this project. At December 31, 2010, our operating results included an aggregate $30 million pre-tax loss, which reflects the costs to complete the project over the contractual revenues as modified.

We were subcontracted to perform development work for a large gas field offshore India. Work commenced in the fourth quarter of 2007 and we completed our scope of work in the third quarter of 2009. To date we have collected approximately $303 million related to this project with an amount of trade receivables yet to be collected. We have requested arbitration in India pursuant to the terms of the subcontract to pursue our claims and the prime contractor has also requested arbitration and has asserted certain counterclaims against us. If we are not successful in resolving these matters through ongoing discussions with the prime contractor, then arbitration in India remains a potential remedy. Based on number of factors associated with the ongoing negotiations with the prime contractor, in 2010 we established an allowance against our trade receivable balance that reduces its balance to an amount we believe is ultimately realizable. However, at the time of this filing no final commercial resolution of this matter has been reached.

We have received value added tax (VAT) assessments from the State of Andhra Pradesh, India (the "State") in the amount of approximately $28 million for the tax years 2010, 2009, 2008 and 2007 related to an Indian subsea construction and diving contract that we entered into in December 2006. The State claims we owe unpaid taxes related to products consumed by us during the period of the contract. We are of the opinion that the State has arbitrarily assessed this VAT tax and has no foundation for the assessment and believe that we have complied with all rules and regulations as related to VAT in the State. We also believe that our position is supported by law and intend to vigorously defend our position. However, the ultimate outcome of this assessment and our potential liability from it, if any, cannot be determined at this time. If the

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current assessment is upheld, it may have a material negative effect on our consolidated results of operations while also impacting our financial position.

See Item 3. Legal Proceedings and Notes 2 and 13 for additional discussion of our contingencies.

Convertible Preferred Stock

We issued a total of $55 million of Convertible Preferred Stock in two separate transactions in January 2003 ($30 million) and June 2004 ($25 million). No preferred shares were outstanding at December 31, 2012 as the holder has redeemed the entire $55 million of shares of our Convertible Preferred Stock. In early 2009, the holder redeemed $49 million of shares of our Convertible Preferred Stock. In connection with this redemption, we recorded an aggregate of $53.4 million beneficial conversion charges. See Note 2 for additional information regarding our Convertible Preferred Stock transactions.

CRITICAL ACCOUNTING ESTIMATES

Our results of operations and financial condition, as reflected in the accompanying consolidated financial statements and related footnotes, are prepared in conformity with accounting principles generally accepted in the United States. As such, we are required to make certain estimates, judgments and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. We base our estimates on historical experience, available information and various other assumptions we believe to be reasonable under the circumstances. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. We believe the most critical accounting policies in this regard are those described below. While these issues require us to make judgments that are somewhat subjective, they are generally based on a significant amount of historical data and current market data. See Note 2 for a detailed discussion on the application of our accounting policies.

Revenue Recognition

Contracting Services Revenues

Revenues from contracting services are derived from contracts, which are both short-term and long-term in duration. Our long-term contracts are contracts that contain either lump-sum turnkey provisions or provisions for specific time, material and equipment charges, which are billed in accordance with the terms of such contracts. We recognize revenue as it is earned at estimated collectible amounts. Further, we record revenue net of taxes collected from customers and remitted to governmental authorities.

Unbilled revenue represents revenue attributable to work completed prior to period end that has not yet been invoiced. All amounts included in unbilled revenue at December 31, 2012 and 2011 are expected to be billed within one year. Collections of all amounts are also expected to be within one year. However, we also monitor the collectability of our outstanding trade receivables on a continual basis in connection with our evaluation of allowance for doubtful accounts.

Revenues generated from specific time, materials and equipment contracts are generally earned on a dayrate basis and recognized as amounts are earned in accordance with contract terms. In connection with these contracts, we may receive revenues for mobilization of equipment and personnel. In connection with new contracts, revenues related to mobilization are deferred and recognized over the period in which contracted services are performed using the straight-line method. Incremental costs incurred directly for mobilization of equipment and personnel to the contracted site, which typically consist of materials, supplies and transit costs, are also deferred and recognized over the period in which contracted services are performed using the straight-line method. Our policy to amortize the revenues and costs related to mobilization on a straight-line basis over the estimated contract service period is consistent with the general pace of activity, level of services being provided and dayrates being earned over the service period of the contract. Mobilization costs to move vessels when a contract does not exist are expensed as incurred.

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Goodwill and Other Intangible Assets

We are required to perform an annual impairment analysis of goodwill. We elected November 1 to be our annual impairment assessment date for goodwill. However, we could be required to evaluate the recoverability of goodwill prior to the annual assessment date if we experience disruption to the business, unexpected significant declines in operating results, divestiture of a significant component of the business, emergence of unanticipated competition, loss of key personnel or a sustained decline in market capitalization. Our goodwill impairment test involves a comparison of the fair value with our carrying amount. The fair value is determined using discounted cash flows and other market-related valuation models. At the time of our annual assessment of goodwill on November 1, 2012 we had two reporting units with goodwill.

In 2011, the Financial Accounting Standards Board ("FASB") issued an update to simplify goodwill impairment testing by giving an entity the option to first assess certain qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If an entity determines it is more likely than not that the fair value of a reporting unit is greater than its carrying amount, then performing the currently prescribed two-step impairment test is unnecessary. We early adopted this standard for its annual goodwill impairment tests in 2011.

Goodwill impairment is determined using a two-step process that requires management to make judgments in determining what assumptions to use in the calculation. The first step is to identify if a potential impairment exists by comparing the fair value of the reporting unit with its carrying amount, including goodwill. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is not considered to have a potential impairment and the second step of the impairment test is not necessary. However, if the carrying amount of a reporting unit exceeds its fair value, the second step is performed to determine if goodwill is impaired and to measure the amount of impairment loss to recognize, if any.

The second step compares the implied fair value of goodwill with the carrying amount of goodwill. If the implied fair value of goodwill exceeds the carrying amount, then goodwill is not considered impaired. However, if the carrying amount of goodwill exceeds the implied fair value, an impairment loss is recognized in an amount equal to that excess. The implied fair value of goodwill is determined in the same manner as the amount of goodwill recognized in a business combination (i.e., the fair value of the reporting unit is allocated to all the assets and liabilities, including any unrecognized intangible assets, as if the reporting unit were acquired in a business combination).

We use both the income approach and market approach to estimate the fair value of our reporting units under the first step. Under the income approach, a discounted cash flow analysis is performed requiring us to make various judgmental assumptions about future revenue, operating margins, growth rates and discount rates. These judgmental assumptions are based on our budgets, long-term business plans, economic projections, anticipated future cash flows and market place data. These assumptions could ultimately be materially different from our future actual results. Under the market approach, the fair value of each reporting unit is calculated by applying an average peer total invested capital EBITDA (defined as earnings before interest, income taxes and depreciation and amortization) multiple to forecasted budgeted EBITDA for each reporting unit. Judgment is required when selecting peer companies that operate in the same or similar lines of business and are potentially subject to the same corresponding economic risks.

All of our remaining goodwill at December 31, 2012 ($62.9 million) was associated with our Contracting Services segment. The reporting units that support the remaining goodwill amounts are strong operationally, and absent any significant downturn in their areas of service, should be able to support their goodwill amounts for the foreseeable future. Based on current and historical evidence supporting these reporting units' carrying value being sufficient to maintain their recorded goodwill amounts, we concluded, as allowed under newly enacted accounting guidance, to forego the historically mandated quantitative step one impairment analysis. We will continue to monitor the current and future operations of these two reporting units to determine whether or not the mandated quantitative assessment is once again necessary. We will conduct the quantitative test at least every three years with the last such test occurring on November 1, 2010.

In 2010, WOSEA placed its main revenue generating asset back in service subsequent to major repairs to this equipment following an incident in which it was damaged. WOSEA also entered into a joint venture in February 2010 (Note 5). Despite these positive developments, WOSEA’s operating results in 2010 were disappointing and its outlook also reflected the uncertainties involving the subsea market in the

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Southeast Asia region, including increased competition and a fragmented market. These factors were considered in our impairment test at November 1, 2010. Based on the results of that evaluation, WOSEA no longer passed its step one test and we concluded that a full write-off of its goodwill ($16.7 million) was required after determining the fair value of its assets under the step two requirements. This impairment charge is reflected as a separate line item in the accompanying consolidated statement of operations titled "Goodwill impairments." WOSEA is part of our Contracting Services segment. There were no goodwill impairments in 2012 or 2011.

Income Taxes

Deferred income taxes are based on the difference between the financial reporting and tax bases of assets and liabilities. We utilize the liability method of computing deferred income taxes. The liability method is based on the amount of current and future taxes payable using tax rates and laws in effect at the balance sheet date. Income taxes have been provided based upon the tax laws and rates in the countries in which operations are conducted and income is earned. A valuation allowance for deferred tax assets is recorded when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized.

We consider the undistributed earnings of our principal non-U.S. subsidiaries to be permanently reinvested. At December 31, 2012, our principal non-U.S. subsidiaries had accumulated earnings and profits of approximately $167.9 million. We have not provided deferred U.S. income tax on the accumulated earnings and profits.

It is our policy to provide for uncertain tax positions and the related interest and penalties based upon management's assessment of whether a tax benefit is more likely than not to be sustained upon examination by tax authorities. At December 31, 2012, we believe we have appropriately accounted for any unrecognized tax benefits. To the extent we prevail in matters for which a liability for an unrecognized tax benefit is established or are required to pay amounts in excess of the liability, our effective tax rate in a given financial statement period may be affected.

See Note 8 for discussion of net operating loss carry forwards, deferred income taxes and uncertain tax positions taken by us.

Derivative Instruments and Hedging Activities

Our risk management activities often involve the use of derivative financial instruments to hedge the impact of market risk exposure. Historically, we have used derivative instruments to reduce our market risk exposure related to oil and gas prices, variable interest rates and foreign currency exchange rates. To reduce the impact of these risks on earnings and increase the predictability of our cash flows, from time to time we have entered into certain derivative contracts, including costless collars and swaps for a portion of our oil and gas production, interest rate swaps, and foreign currency forward contracts. These derivative contracts are reflected in our balance sheet at fair value.

We formally document all relationships between hedging instruments and the related hedged items, as well as our risk management objectives, strategies for undertaking various hedge transactions and our methods for assessing and testing correlation and hedge ineffectiveness. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows of the hedged items. Changes in the assumptions used could impact whether the fair value change in the hedged instrument is charged to earnings or accumulated other comprehensive income (loss).

The fair value of our oil and gas derivative contracts reflects our best estimate and is based upon exchange or over-the-counter quotations whenever they are available. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, we utilize other valuation techniques or models to estimate market values. The fair value of our interest rate swaps is calculated as the discounted cash flows of the difference between the rate fixed by the hedge instrument and the LIBOR forward curve over the remaining term of the hedge instrument. The fair value of our foreign currency forward exchange contracts is calculated as the discounted cash flows of the difference between the fixed payment as specified by the

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hedge instrument and the expected cash inflow of the forecasted transaction using a foreign currency forward curve.

These modeling techniques require us to make estimates of future prices, price correlation and market volatility and liquidity. Our actual results may differ from our estimates, and these differences can be positive or negative.

We engage solely in cash flow hedges. Changes in the derivative fair values that are designated as cash flow hedges are deferred to the extent that they are effective and are recorded as a component of accumulated other comprehensive income or loss (a component of shareholders' equity) until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings. In addition, any change in the fair value of a derivative that does not qualify for hedge accounting is recorded in earnings in the period in which the change occurs (Notes 2 and 17).

As a result of the announcement of the sale of ERT, we de-designated all of our remaining oil and natural gas derivative contracts as hedging instruments. In addition, under the terms of our Credit Agreement (Note 7), we are required to use at a minimum 60% of the after-tax proceeds from the sales of the Caesar, the Express and ERT to make payments to reduce our Term Loan debt and borrowings under the Revolving Credit Facility. Because it was probable that we would pay off the Term Loan debt before the expiration of our interest rate swaps, we separately concluded that the swaps no longer qualified as cash flow hedges. At December 31, 2012, all of our commodity derivative contracts and our interest rate swaps were subject to mark-to-market adjustments to reflect the changes in their fair values. In connection with the de-designation of these derivative contracts as hedging instruments, we were required to recognize amounts previously recorded in accumulated other comprehensive income (loss) and related deferred taxes into earnings. We settled all of our remaining commodity derivative contracts and interest swap contracts in February 2013. See Notes 2 and 17 for additional information regarding our derivative contracts.

Property and Equipment

Property and equipment is recorded at cost. Depreciation expense is derived primarily using the straight-line method over the estimated useful lives of the assets (Note 2).

Assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value and reported as an impairment (a component of cost of sales) in the periods in which the determination of the impairment is made. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. Our marine vessels are assessed on a vessel by vessel basis, while our ROVs are grouped and assessed by asset class. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants or based on a multiple of operating cash flows validated with historical market transactions of similar assets where possible. The expected future cash flows used for impairment reviews and related fair value calculations are based on judgmental assessments of operating costs, project margins and capital project decisions, considering all available information at the date of review. If an impairment has occurred, we recognize a loss for the difference between the carrying amount and the fair value of the asset. In 2012, we recorded asset impairment charges of $14.6 million for the Intrepid, $157.8 million for the Caesar and related mobile pipelay equipment, and $4.6 million for well intervention assets at our former operations in Australia (Note 2).

Assets are classified as held for sale when a formal plan to dispose of the assets exists and those assets meet the held for sale criteria. Assets held for sale are reviewed for potential loss on sale when we commit to a plan to sell and thereafter while the asset is held for sale. Losses are measured as the difference between the fair value less costs to sell and the asset's carrying value. Estimates of anticipated sales prices are judgmental and subject to revisions in future periods, although initial estimates are typically based on sales prices for similar assets and other valuation data.

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Equity Investments

We periodically review our investments in Deepwater Gateway and Independence Hub for impairment. Under the equity method of accounting, an impairment loss would be recorded whenever a decline in value of an equity investment below its carrying amount is determined to be other than temporary. In judging "other than temporary," we would consider the length of time and extent to which the fair value of the investment has been less than the carrying amount of the equity investment, the near-term and longer-term operating and financial prospects of the equity company and our longer-term intent of retaining the investment in the entity. We previously invested in an Australian joint venture that engaged in well intervention operations in the Southeast Asia region. We fully impaired our investment in that joint venture and recorded a $10.6 million other than temporary impairment charge in 2011. We exited this Australian joint venture in 2012 (Note 5).

NEW ACCOUNTING STANDARDS

In December 2011, the FASB issued ASU No. 2011-11, "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities" ("ASU 2011-11"). Offsetting, otherwise known as netting, is the presentation of assets and liabilities as a single net amount in the statement of financial position (balance sheet). U.S. GAAP allows companies the option to present net in their balance sheets derivatives that are subject to a legally enforceable netting arrangement with the same party where rights of set-off are only available in the event of default or bankruptcy. ASU 2011-11 requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. An entity is required to apply the amendments for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. An entity should provide the disclosures required by those amendments retrospectively for all comparative periods presented. We are currently assessing the impact of ASU 2011-11 on our consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

As of December 31, 2012, we were exposed to market risk in three major areas: interest rates, commodity prices and foreign currency exchange rates.

Interest Rate Risk. As of December 31, 2012, $467.2 million of our outstanding debt was subject to floating rates. The interest rate applicable to our variable rate debt may rise, increasing our interest expense and related cash outlay. To reduce the impact of this market risk, in August 2011, we entered into interest rate swap contracts to fix the interest rate on $200 million of our Term Loan debt. These swap contracts, which are settled monthly, began in January 2012 and extend through January 2014. The impact of market risk is estimated using a hypothetical increase in interest rates by 100 basis points for our variable rate long-term debt that is not hedged. Based on this hypothetical assumption, we would have incurred an additional $2.5 million in interest expense for the year ended December 31, 2012. As a result of the sale of ERT, in February 2013, we repaid all of the Term Loan B and settled all of our remaining interest rate swaps for $0.6 million.

Commodity Price Risk. We historically utilized commodity derivative financial instruments to achieve a more predictable cash flow associated with ERT.

As of December 31, 2012, we had derivative contracts related to our oil and gas production activities totaling approximately 2.7 million barrels of oil and 6.0 Bcf of natural gas. At December 31, 2012, our existing contracts are as follows:

Production Period	Average	Weighted Average

	Instrument Type	Monthly Volumes	Price (1)
Crude Oil:			(per barrel)
January 2013 — December 2013	Swap	88.9 MBbl	$95.28
January 2013 — December 2013	Collar	133.3 MBbl	$98.44 — $115.85
Natural Gas:			(per Mcf)
January 2013 — December 2013	Swap	500.0 Mmcf	$4.09

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(1) The prices quoted in the table above are NYMEX Henry Hub for natural gas. Our oil contracts are indexed to the Brent crude oil price.

Following the sale of ERT, we settled all of our remaining commodity derivative contracts in February 2013 for approximately $22.5 million, resulting in a loss of approximately $12 million.

Foreign Currency Exchange Rate Risk. Because we operate in various regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar (primarily with respect to Helix Well Ops (U.K.) Limited ("WOUK")). The functional currency for WOUK is the applicable local currency (British Pound). Previously, WOSEA also had currency risk as its functional currency was the applicable local currency (Australian Dollar). We ceased operations in Australia in 2012. Although revenues are denominated in the local currency, the effects of foreign currency fluctuations are partly mitigated because the local expenses of such foreign operations are also generally denominated in the same currency.

Assets and liabilities of WOUK and WOSEA are translated using the exchange rates in effect at the balance sheet date, resulting in translation adjustments that are reflected in accumulated other comprehensive income (loss) in the shareholders' equity section of our consolidated balance sheet. At December 31, 2012, approximately 12% of our assets are impacted by changes in foreign currencies in relation to the U.S. dollar. We recorded unrealized gains (losses) of $7.3 million, $(1.0) million and $(10.0) million to accumulated other comprehensive income (loss) for the years ended December 31, 2012, 2011 and 2010, respectively. Deferred taxes have not been provided on foreign currency translation adjustments since we consider our undistributed earnings (when applicable) of our non-U.S. subsidiaries to be permanently reinvested.

We also have other subsidiaries with operations in the United Kingdom, Asia Pacific, Europe and Australia. These international subsidiaries conduct the majority of their operations in these regions in U.S. dollars which is their functional currency. When currencies other than the U.S. dollar are to be paid or received, the resulting transaction gain or loss is recognized in the consolidated statements of operations as a component of other income (expense). These amounts resulted in a gains (loss) of $(0.5) million, $(2.1) million and $1.9 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Our cash flows are subject to fluctuations resulting from changes in foreign currency exchange rates. Fluctuations in exchange rates are likely to impact our business and cash flows in the future. As a result, we entered into various foreign currency forward purchase contracts to stabilize expected cash outflows relating to certain vessel charters denominated in British pounds. The aggregate fair value of the foreign currency forwards was a net asset of $0.1 million as of December 31, 2012 and a net liability of $0.1 million at December 31, 2011. The gain (losses) resulting from changes in the fair value of our foreign currency forwards that were not designated for hedge accounting (Note 17) totaled $0.4 million, $0.2 million and $(2.6) million for the years ended December 31, 2012, 2011 and 2010, respectively.

In January 2013, we entered into foreign currency exchange contracts to hedge the foreign currency exposure to potential variability in cash flows associated with Grand Canyon charter payments ($104.6 million) denominated in Norwegian Kroner (NOK591.3 million), through September 2017. These contracts currently qualify for hedge accounting treatment.

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Item 8. Financial Statements and Supplementary Data.

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. The Company's internal control system was designed to provide reasonable assurance to the Company's management and Board of Directors regarding the reliability of financial reporting and the preparation and fair presentation of financial statements for external purposes in accordance with U.S. 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.

In making its assessment, management has utilized the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework. Based on this assessment, management has concluded that, as of December 31, 2012, the Company's internal control over financial reporting is effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

Ernst & Young LLP has issued an attestation report on the Company's internal control over financial reporting as of December 31, 2012, which is included herein.

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of
Helix Energy Solutions Group, Inc. and Subsidiaries

We have audited Helix Energy Solutions Group, 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). Helix Energy Solutions Group, 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, Helix Energy Solutions Group, 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 Helix Energy Solutions Group, Inc. and subsidiaries as of December 31, 2012 and 2011, and the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2012 and our report dated February 22, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 22, 2013

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Helix Energy Solutions Group, Inc. and Subsidiaries

We have audited the accompanying consolidated balance sheets of Helix Energy Solutions Group, Inc. and subsidiaries as of December 31, 2012 and 2011, and the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We did not audit the financial statements of Deepwater Gateway, L.L.C. (a corporation in which the Company has a 50% interest) and Independence Hub, LLC (a corporation in which the Company has a 20% interest). In the consolidated financial statements, the Company’s equity investments includes approximately $168 million and $176 million from Deepwater Gateway, L.L.C. and Independence Hub, LLC combined at December 31, 2012 and 2011, respectively, and the Company’s equity in earnings of investments includes approximately $8 million, $20 million and $23 million for the three years in the period ended December 31, 2012 from Deepwater Gateway, L.L.C. and Independence Hub, LLC combined. Those statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Deepwater Gateway, L.L.C. and Independence Hub, LLC, is based solely on the report of the other auditors.

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 and the reports of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the reports of other auditors, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Helix Energy Solutions Group, 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.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Helix Energy Solutions Group, 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 22, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 22, 2013

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REPORT OF INDEPENDENT REGISTERED ACCOUNTING FIRM

To the Management Committee of
Deepwater Gateway, L.L.C.
Houston, Texas

We have audited the balance sheets of Deepwater Gateway, L.L.C. (the "Company") as of December 31, 2012 and 2011, and the related statements of operations, cash flows and members' equity for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Houston, Texas
February 15, 2013

REPORT OF INDEPENDENT REGISTERED ACCOUNTING FIRM

To the Management Committee of
Independence Hub, LLC
Houston, Texas

We have audited the balance sheets of Independence Hub, LLC (the "Company") as of December 31, 2012 and 2011, and the related statements of operations, cash flows, and members' equity for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Houston, Texas
February 15, 2013

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands)

	December 31, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 437,100	$ 546,463
Accounts receivable:		
Trade, net of allowance for uncollectible accounts of $5,152 and $4,000, respectively	152,233	147,899
Unbilled revenue	26,992	24,338
Costs in excess of billing	6,848	13,037
Other current assets	96,934	93,584
Current assets of discontinued operations	84,000	118,921
Total current assets	804,107	944,242
Property and equipment	2,051,796	1,815,012
Less accumulated depreciation	(565,921)	(355,343)
Property and equipment, net	1,485,875	1,459,669
Other assets:		
Equity investments	167,599	175,656
Goodwill	62,935	62,215
Other assets, net	49,837	35,166
Non-current assets of discontinued operations	816,227	905,399
Total assets	$ 3,386,580	$ 3,582,347
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 92,398	$ 73,919
Accrued liabilities	161,514	146,112
Income tax payable	—	1,293
Current maturities of long-term debt	16,607	7,877
Current liabilities of discontinued operations	182,527	166,975
Total current liabilities	453,046	396,176
Long-term debt	1,002,621	1,147,444
Deferred tax liabilities	359,237	417,610
Other non-current liabilities	5,025	9,368
Non-current liabilities of discontinued operations	147,237	161,208
Total liabilities	1,967,166	2,131,806
Convertible preferred stock	—	1,000
Commitments and contingencies		
Shareholders' equity:		
Common stock, no par, 240,000 shares authorized, 105,763 and 105,530 shares issued, respectively	932,742	908,776
Retained Earnings	476,310	522,644
Accumulated other comprehensive loss	(15,667)	(10,017)

Total controlling interest shareholders' equity	1,393,385	1,421,403
Noncontrolling interest	26,029	28,138
Total equity	1,419,414	1,449,541
Total liabilities and shareholders' equity	$ 3,386,580	$ 3,582,347

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

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share amounts)

	Year Ended December 31, 2012	2011	2010
Net Revenues	$846,109	$702,000	$774,469
Cost of sales:			
Cost of sales	619,059	545,753	605,575
Impairments	177,135	6,564	4,077
Total cost of sales	796,194	552,317	609,652
Gross profit	49,915	149,683	164,817
Goodwill impairment	—	—	(16,743)
Non-hedge loss on commodity derivative contracts	(10,507)	—	—
Gain (loss) on sale of assets, net	(13,476)	(6)	9,118
Selling, general and administrative expenses	(94,415)	(86,637)	(106,113)
Income (loss) from operations	(68,483)	63,040	51,079
Equity in earnings of investments	8,434	22,215	19,469
Other than temporary loss on equity investments	—	(10,563)	(2,240)
Net interest expense	(48,160)	(70,181)	(65,589)
Loss on early extinguishment of long-term debt	(17,127)	(2,354)	—
Other expense, net	(625)	(1,107)	(1,049)
Income (loss) before income taxes	(125,961)	1,050	1,670
Income tax provision (benefit)	(59,158)	(36,806)	19,166
Income (loss) from continuing operations	(66,803)	37,856	(17,496)
Income (loss) from discontinued operations, net of tax	23,684	95,221	(106,657)
Net income (loss), including noncontrolling interests	(43,119)	133,077	(124,153)
Less net income applicable to noncontrolling interests	(3,178)	(3,098)	(2,835)
Net income (loss) applicable to Helix	(46,297)	129,979	(126,988)
Preferred stock dividends	(37)	(40)	(114)
Net income (loss) applicable to Helix common shareholders	$(46,334)	$129,939	$(127,102)
Basic earnings (loss) per share of common stock:			
Continuing operations	$(0.67)	$0.33	$(0.19)
Discontinued operations	0.23	0.90	(1.03)
Net income (loss) per common share	$(0.44)	$1.23	$(1.22)
Diluted earnings (loss) per share of common stock:			
Continuing operations	$(0.67)	$0.33	$(0.19)
Discontinued operations	0.23	0.90	(1.03)
Net income (loss) per common share	$(0.44)	$1.23	$(1.22)
Weighted average common shares outstanding:			
Basic	104,449	104,528	103,857

Diluted	104,449	104,953	103,857

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

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in thousands)

	Year Ended December 31, 2012	2011	2010
Net income (loss), including noncontrolling interests	$(43,119)	$133,077	$(124,153)
Other comprehensive income (loss), net of taxes:			
Foreign currency translation gain	8,368	(1,118)	(11,108)
Income taxes on foreign currency translation gain	(1,077)	116	1,103
Foreign currency translation gain, net of tax	7,291	(1,002)	(10,005)
Unrealized gain (loss) on hedges arising during the period	(33,078)	69,889	(35,571)
Reclassification adjustments for (gain) loss included in net income	2,661	(23,669)	23,726
Reclassification adjustments for loss from derivatives de-designated as cash flow hedges included in net income	10,507	—	—
Income taxes on unrealized gain (loss) on hedges	6,969	(16,177)	4,146
Unrealized gain (loss) on hedges, net of tax	(12,941)	30,043	(7,699)
Unrealized gain on investment held for sale	—	—	1,220
Income taxes on unrealized gain on investment held for sale	—	—	(333)
Unrealized gain on investment held for sale, net of tax	—	—	887
Other comprehensive income (loss), net of taxes	(5,650)	29,041	(16,817)
Comprehensive income (loss)	(48,769)	162,118	(140,970)
Less comprehensive income applicable to noncontrolling interests	(3,178)	(3,098)	(2,835)
Comprehensive income (loss) applicable to Helix	(51,947)	159,020	(143,805)
Preferred stock dividends	(37)	(40)	(114)
Comprehensive income (loss) applicable to Helix common shareholders	$(51,984)	$158,980	$(143,919)

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

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(in thousands)

	Helix Energy Solutions Shareholders' Equity						
	Common Stock						
	Shares	Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Controlling Interest Shareholders' Equity	Non-controlling interest	Total Equity
Balance, December 31, 2009	104,281	$ 907,691	$ 519,807	$ (22,241)	$ 1,405,257	$ 22,205	$ 1,427,462
Net income (loss)	—	—	(126,988)	—	(126,988)	2,835	(124,153)
Foreign currency translation adjustments	—	—	—	(10,005)	(10,005)	—	(10,005)
Unrealized loss on hedges, net	—	—	—	(7,699)	(7,699)	—	(7,699)
Unrealized gain on investment held for sale (Note 2)	—	—	—	887	887	—	887
Convertible preferred stock dividends	—	—	(114)	—	(114)	—	(114)
Convertible preferred stock conversion (Note 10)	1,807	5,000	—	—	5,000	—	5,000
Stock compensation expense	—	9,217	—	—	9,217	—	9,217
Stock repurchase	(1,016)	(11,680)	—	—	(11,680)	—	(11,680)
Activity in company stock plans, net and other	520	674	—	—	674	—	674
Excess tax from stock-based compensation	—	(3,945)	—	—	(3,945)	—	(3,945)
Balance, December 31, 2010	105,592	$ 906,957	$ 392,705	$ (39,058)	$ 1,260,604	$ 25,040	$ 1,285,644
Net income (loss)	—	—	129,979	—	129,979	3,098	133,077
Foreign currency translation adjustments	—	—	—	(1,002)	(1,002)	—	(1,002)
Unrealized loss on hedges, net	—	—	—	30,043	30,043	—	30,043
Convertible preferred stock dividends	—	—	(40)	—	(40)	—	(40)
Stock compensation expense	—	8,418	—	—	8,418	—	8,418

Stock repurchase	(497)	(6,502)	—	—	(6,502)	—	(6,502)
Activity in company stock plans, net and other	435	916	—	—	916	—	916
Excess tax from stock-based compensation	—	(1,013)	—	—	(1,013)	—	(1,013)
Balance, December 31, 2011	105,530	$ 908,776	$ 522,644	$ (10,017)	$ 1,421,403	$ 28,138	$ 1,449,541
Net income (loss)	—	—	(46,297)	—	(46,297)	3,178	(43,119)
Foreign currency translation adjustments	—	—	—	7,291	7,291	—	7,291
Unrealized loss on hedges, net	—	—	—	(12,941)	(12,941)	—	(12,941)
Dividend payment	—	—	—	—	—	(5,287)	(5,287)
Equity component of debt discount on Convertible Senior Note due 2032	—	22,419	—	—	22,419	—	22,419
Convertible preferred stock dividends	—	—	(37)	—	(37)	—	(37)
Convertible preferred stock conversion (Note 10)	362	1,000	—	—	1,000	—	1,000
Stock compensation expense	—	7,361	—	—	7,361	—	7,361
Stock repurchase	(405)	(6,415)	—	—	(6,415)	—	(6,415)
Activity in company stock plans, net and other	276	787	—	—	787	—	787
Excess tax from stock-based compensation	—	(1,186)	—	—	(1,186)	—	(1,186)
Balance, December 31, 2012	105,763	$ 932,742	$ 476,310	$ (15,667)	$ 1,393,385	$ 26,029	$ 1,419,414

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

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2012	2011	2010
Cash flows from operating activities:			
Net income (loss), including noncontrolling interests	$(43,119)	$133,077	$(124,153)
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by operating activities:			
(Income) loss from discontinued operations	(23,684)	(95,221)	106,657
Depreciation and amortization	97,201	91,188	81,878
Asset impairment charge	177,135	6,564	4,077
Goodwill and other indefinite-lived intangible impairments	—	—	16,743
Amortization of deferred financing costs	9,086	8,910	7,703
Stock-based compensation expense	7,627	6,973	7,475
Amortization of debt discount	9,729	8,973	8,409
Deferred income taxes	(69,584)	(4,188)	(46,836)
Excess tax from stock-based compensation	1,186	1,013	3,945
Gain on investment in Cal Dive common stock	—	(753)	—
(Gain) loss on sale of assets, net	13,476	6	(9,118)
Loss on early extinguishment of debt	17,127	2,354	—
Other than temporary loss on equity investments	—	10,563	2,240
Unrealized gain and ineffectiveness on derivative contracts, net	(250)	382	1,568
Changes in operating assets and liabilities:			
Accounts receivable, net	(3,652)	(30,491)	(29,727)
Other current assets	(10,434)	18,783	(2,088)
Income tax payable	(16,812)	6,472	214
Accounts payable and accrued liabilities	73,448	23,191	47,992
Oil and gas asset retirement costs	(37,970)	(4,907)	—
Other noncurrent, net	(24,442)	(231)	(5,607)
Net cash provided by operating activities	176,068	182,658	71,372
Net cash provided by discontinued operations	276,430	384,498	260,082
Net cash provided by operating activities	452,498	567,156	331,454
Cash flows from investing activities:			
Capital expenditures	(323,039)	(100,154)	(122,218)
Distributions from equity investments, net	7,797	1,266	2,286
Proceeds from sale of assets	19,530	—	6,042
Proceeds from insurance reimbursement	—	—	7,020
Proceeds from sale of Cal Dive common stock	—	3,588	—
Net cash used in investing activities	(295,712)	(95,300)	(106,870)
Net cash used in discontinued operations	(120,057)	(87,017)	(74,686)
Net cash used in investing activities	$(415,769)	$(182,317)	$(181,556)

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(CONTINUED)
(in thousands)

	Year Ended December 31,		
	2012	2011	2010
Cash flows from financing activities:			
Early extinguishment of Senior Unsecured Notes	$(209,500)	$(77,394)	$ —
Borrowings under revolving credit facility	100,000	109,400	—
Repayment of revolving credit facility	—	(109,400)	—
Issuance of Convertible Senior Notes due 2032	200,000	—	—
Repurchase of Convertible Senior Notes due 2025	(298,288)	—	—
Proceeds from Term Loan A	100,000	—	—
Repayment of Term Loans	(12,569)	(130,691)	(4,326)
Repayment of MARAD borrowings	(4,877)	(4,645)	(4,424)
Deferred financing costs	(7,580)	(9,311)	(2,947)
Distributions to noncontrolling interest	(5,287)	—	—
Repurchases of common stock	(7,197)	(7,604)	(11,680)
Excess tax from stock-based compensation	(1,186)	(1,013)	(3,945)
Exercise of stock options, net and other	1,252	763	(1,957)
Net cash used in financing activities	(145,232)	(229,895)	(29,279)
Effect of exchange rate changes on cash and cash equivalents	(860)	436	(207)
Net increase (decrease) in cash and cash equivalents	(109,363)	155,380	120,412
Cash and cash equivalents:			
Balance, beginning of year	546,465	391,085	270,673
Balance, end of year	437,102	546,465	391,085
Less cash from discontinued operations, end of year	2	2	1
Cash from continuing operations, end of year	$437,100	$546,463	$391,084

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

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 — Organization

Effective March 6, 2006, we changed our name from Cal Dive International, Inc. to Helix Energy Solutions Group, Inc. ("Helix" or the "Company"). Unless the context indicates otherwise, the terms "we," "us" and "our" in this Annual Repor refer collectively to Helix and its subsidiaries. Until June 2009, Cal Dive International, Inc. (collectively with its subsidiaries referred to as "Cal Dive" or "CDI") was a majority-owned subsidiary of Helix. We sold substantially all of our remaining ownership interests in Cal Dive during 2009 (Note 2). We are an international offshore energy company that provides specialty services to the offshore energy industry, with a focus on our growing well intervention and robotics operations. Our contracting services operations are located primarily in the Gulf of Mexico, North Sea, Asia Pacific, and West Africa regions. In February 2013, we sold Energy Resource Technology GOM, Inc. ("ERT"), a former wholly-owned U.S. subsidiary that conducted our oil and gas operations in the Gulf of Mexico. Our former Oil and Gas segment was involved in prospect generation, exploration, development and production activities in the Gulf of Mexico.

Contracting Services Operations

We seek to provide services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. Our "life of field" services are segregated into four disciplines: well intervention, robotics, subsea construction and production facilities. We have disaggregated our contracting services operations into two reportable segments: Contracting Services and Production Facilities. Our Contracting Services segment includes well intervention, robotics and subsea construction operations (see Note 2 for disclosures regarding the planned dispositions of our subsea construction vessels and related assets). Our Production Facilities business includes our majority ownership of the Helix Producer I ("HP I") vessel as well as our equity investments in Deepwater Gateway, L.L.C. ("Deepwater Gateway") and Independence Hub, LLC ("Independence Hub") (Note 5). It also includes the Helix Fast Response System ("HFRS"), which includes access to our Q4000 and HP I vessels. In 2011, we signed an agreement with Clean Gulf Associates ("CGA"), a non-profit industry group, allowing, in exchange for a retainer fee, the HFRS to be named as a response resource in permit applications to federal and state agencies, and making the HFRS available to certain CGA participants who have executed utilization agreements with us. In addition to the agreement with CGA, we currently have separate utilization agreements with 24 CGA participant member companies. These agreements specify the day rates to be charged should the HFRS be deployed in connection with a well control incident. Recently, this group of operators formed HWCG LLC to perform the same functions as CGA with respect to the HFRS. The retainer fee for the HFRS became effective April 1, 2011. We anticipate that a new contract covering the HFRS will be signed in the first quarter of 2013 to provide for a four-year term commencing April 1, 2013.

Discontinued Operations

In December 2012, we announced a definitive agreement for the sale of ERT. On February 6, 2013, we sold ERT for $620 million plus contingent consideration in the form of overriding royalty interests in the Wang well and certain other future exploration prospects. As a result, we have presented the assets and liabilities included in the sale of ERT and the historical operating results of our former Oil and Gas segment as discontinued operations in the accompanying consolidated financial statements. See Note 3 for additional information regarding our discontinued oil and gas operations.

Note 2 — Summary of Significant Accounting Policies

Principles of Consolidation

Our consolidated financial statements include the accounts of majority-owned subsidiaries. The equity method is used to account for investments in affiliates in which we do not have majority ownership, but have the ability to exert significant influence. We account for our Deepwater Gateway, Independence Hub and former Australian joint venture investments under the equity method of accounting. Noncontrolling interests represent the minority shareholders' proportionate share of the equity in Kommandor LLC. All material intercompany accounts and transactions have been eliminated. Certain reclassifications were made to

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previously-reported amounts in the consolidated financial statements and notes thereto to make them consistent with the current presentation format. The most significant of these reclassifications are associated with our discontinued oil and gas operations. As noted in Note 1, ERT qualified as discontinued operations in December 2012 following the announcement of a definitive agreement for the sale of ERT. Accordingly, all operations and financial positions related to ERT have been presented as discontinued operations even if they did not qualify as a discontinued operation in that period.

Use of Estimates

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

Cash and Cash Equivalents

Cash and cash equivalents are highly liquid financial instruments with original maturities of three months or less. They are carried at cost plus accrued interest, which approximates fair value.

Statement of Cash Flow Information

The following table provides supplemental cash flow information for the periods stated (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Interest paid, net of interest capitalized	$68,735	$81,000	$68,534
Income taxes paid	$43,111	$11,216	$10,071

Total non-cash investing activities for the years ended December 31, 2012, 2011 and 2010 included $51.1 million, $26.1 million and $21.9 million, respectively, of accruals for property and equipment capital expenditures.

Accounts Receivable and Allowance for Uncollectible Accounts

Accounts receivable are stated at the historical carrying amount net of write-offs and allowance for uncollectible accounts. The amount of our net accounts receivable approximates fair value. We establish an allowance for uncollectible accounts receivable based on historical experience and any specific customer collection issues that we have identified. Uncollectible accounts receivable are written off when a settlement is reached for an amount that is less than the outstanding historical balance or when we have determined that the balance will not be collected (Note 15).

Property and Equipment

Overview. Property and equipment is recorded at cost. Property and equipment is depreciated on a straight line basis over the estimated useful life of each respective asset. The following is a summary of the gross components of property and equipment (dollars in thousands):

	Estimated Useful Life	2012	2011
ROVs/Vessels	10 to 30 years	$1,822,642	$1,616,772
Machinery, equipment, buildings and leasehold improvements	5 to 30 years	229,154	198,240
Total property and equipment		$2,051,796	$1,815,012

The cost of repairs and maintenance is charged to expense as incurred, while the cost of improvements is capitalized. The repair and maintenance expenses totaled $38.7 million, $32.3 million and $29.3 million for the years ended December 31, 2012, 2011 and 2010, respectively. Included in machinery,

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equipment, buildings and leasehold improvements were $18.5 million and $18.1 million of capitalized software costs at December 31, 2012 and 2011, respectively. The total amount charged to expense related to the amortization of these software costs was $2.6 million during each of the years ended December 31, 2012, 2011 and 2010.

Assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value and reported as an impairment charge in the periods in which the determination of the impairment is made. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. Our marine vessels are assessed on a vessel by vessel basis, while our ROVs are grouped and assessed by asset class. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants or based on a multiple of operating cash flows validated with historical market transactions of similar assets where possible. The expected future cash flows used for impairment reviews and related fair value calculations are based on judgmental assessments, operating costs, project margins and capital project decisions, considering all available information at the date of review. If an impairment has occurred, we recognize a loss for the difference between the carrying amount and the fair value of the asset.

In 2012, we decided to cease our well intervention operations in Australia. We recorded a $4.6 million impairment charge to reduce our well intervention assets in Australia to their fair value of $5.0 million. In 2011, in association with the reorganization of our Australian well intervention operations, we conducted an impairment assessment of its subsea well intervention equipment, which resulted in a $6.6 million charge to reduce the carrying value of such well intervention equipment to its then estimated fair value. In 2012, as a result of diminished work opportunities for the Intrepid, we placed the vessel in cold-stack mode and later sold the vessel for $14.5 million in cash, which resulted in asset impairment and related loss on disposal charges totaling $28.1 million for the Intrepid. Also in 2012, we entered into an agreement to sell our two remaining pipelay vessels, the Express and the Caesar, and other related pipelay equipment for a total sales price of $238.3 million, of which we have received a $50 million deposit that is only refundable in very limited circumstances. The sales of these vessels are scheduled to close and fund in two stages in 2013 following the completion of each vessel's existing backlog of work. In connection with the announcement of the sale of our remaining pipelay vessels and related equipment, we recorded an impairment charge of $157.8 million to reduce the carrying cost of the Caesar and other related pipelay equipment to their respective fair values as determined by the definitive sales agreement. We did not record impairments related to our vessels during 2011 and 2010. See Note 3 for disclosure related to the impairment charges associated with certain of our former oil and gas properties.

Assets are classified as held for sale when we have a formalized plan for disposal and those assets meet the held for sale criteria. Assets classified as held for sale are included in other current assets. There were no assets meeting the requirements to be classified as assets held for sale at December 31, 2012 other than assets associated with our discontinued oil and gas operations (Note 3). We had no assets classified as assets held for sale at December 31, 2011.

Interest from external borrowings is capitalized on major projects until the assets are ready for their intended use. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful life of the asset in the same manner as the underlying asset. The total of our interest expense capitalized during each of the three years ended December 31, 2012, 2011 and 2010 was $4.9 million, $1.3 million and $12.5 million, respectively.

Equity Investments

We periodically review our equity investments in Deepwater Gateway and Independence Hub for impairment. Under the equity method of accounting, an impairment loss would be recorded whenever the fair value of an equity investment is determined to be below its carrying amount and the reduction is considered to be other than temporary. In judging "other than temporary," we would consider the length of time and extent to which the fair value of the investment has been less than the carrying amount of the equity investment, the near-term and long-term operating and financial prospects of the equity company and our longer-term intent of retaining the investment in the entity. We previously invested in an Australian joint venture that engaged in well intervention operations in the Southeast Asia region. We fully impaired our investment in that joint venture and recorded a $10.6 million other than temporary impairment charge in 2011. We exited this Australian joint venture in 2012. See Note 5 for discussion of other than temporary loss amounts recorded in both 2011 and 2010.

Goodwill and Other Intangible Assets

We are required to perform an annual impairment analysis of goodwill. We elected November 1 to be our annual impairment assessment date for goodwill. However, we could be required to evaluate the recoverability of goodwill prior to the annual assessment date if we experience disruption to the business, unexpected significant declines in operating results, divestiture of a significant component of the business, emergence of unanticipated competition, loss of key personnel or a sustained decline in market capitalization. Our goodwill impairment test involves a comparison of the fair value with our carrying amount. The fair value is determined using discounted cash flows and other market-related valuation models. At the time of our annual assessment of goodwill on November 1, 2012 we had two reporting units with goodwill and our impairment analysis.

Goodwill impairment is determined using a two-step process. The first step is to identify if a potential impairment exists by comparing the fair value of the reporting unit with its carrying amount, including goodwill. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is not considered to have a potential impairment and the second step of the impairment test is not necessary. However, if the carrying amount of a reporting unit exceeds its fair value, the second step is performed to determine if goodwill is impaired and to measure the amount of impairment loss to recognize, if any.

The second step compares the implied fair value of goodwill with the carrying amount of goodwill. If the implied fair value of goodwill exceeds the carrying amount, then goodwill is not considered impaired. However, if the carrying amount of goodwill exceeds the implied fair value, an impairment loss is recognized in an amount equal to that excess. The implied fair value of goodwill is determined in the same manner as the amount of goodwill recognized in a business combination (i.e., the fair value of the reporting unit is allocated to all the assets and liabilities, including any unrecognized intangible assets, as if the reporting unit were acquired in a business combination).

We use both the income approach and market approach to estimate the fair value of our reporting units under the first step of our goodwill impairment assessment. Under the income approach, a discounted cash flow analysis is performed requiring us to make various judgmental assumptions about future revenue, operating margins, growth rates and discount rates. These judgmental assumptions are based on our budgets, long-term business plans, economic projections, anticipated future cash flows and market place data. Under the market approach, the fair value of each reporting unit is calculated by applying an average peer total invested capital EBITDA (defined as earnings before interest, income taxes and depreciation and amortization) multiple to the upcoming fiscal year’s forecasted EBITDA for each reporting unit. Judgment is required when selecting peer companies that operate in the same or similar lines of business and are potentially subject to the same economic risks.

In 2011, the Financial Accounting Standards Board (“FASB”) issued an update to simplify goodwill impairment testing by giving an entity the option to first assess certain qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount including goodwill. If an entity determines it is more likely than not that the fair value of a reporting unit is greater than its carrying amount, then performing the currently prescribed two-step impairment test is unnecessary. The Company early adopted this standard for its annual goodwill impairment tests in 2011.

All of our remaining goodwill at December 31, 2012 ($62.9 million) was associated with our Contracting Services segment. The reporting units that support the remaining goodwill amounts are strong operationally, and absent any significant downturn in their areas of service, should be able to support their goodwill amounts for the foreseeable future. Based on the current and historical evidence supporting these reporting units' carrying value being sufficient to maintain their recorded goodwill amounts, we concluded, as allowed under applicable accounting guidance, to forego the quantitative step one impairment analysis. We will continue to monitor the current and future operations of these two reporting units to determine whether or not the quantitative assessment is once again necessary. We will conduct the quantitative test at least every three years with the last such test occurring on November 1, 2010.

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The changes in the carrying amount of goodwill are as follows (in thousands):

Balance at December 31, 2010 (1)	$62,494
Other adjustments (2)	(279)
Balance at December 31, 2011	62,215
Other adjustments (2)	720
Balance at December 31, 2012	$62,935

(1) In 2010, we fully impaired $16.7 million of goodwill associated with our Australian well intervention subsidiary ("WOSEA") (see below).

(2) Reflects foreign currency adjustment for certain amounts of our goodwill.

In 2010, WOSEA placed its main revenue generating asset back in service subsequent to major repairs to this equipment following an incident in which it was damaged. WOSEA also entered into an Australian joint venture in February 2010 (Note 5). Despite these positive developments, in 2010 WOSEA's operating results were disappointing and its near-term outlook reflected the uncertainties involving the subsea market in the Southeast Asia region, including increased competition and a fragmented market. These factors were considered in our impairment test at November 1, 2010. Based on the results of that evaluation, WOSEA no longer passed its step one test and we concluded that a full write-off of its goodwill ($16.7 million) was required after we determined the fair value of its assets under the step two requirements. This impairment charge is reflected as a separate line item in the accompanying consolidated statement of operations titled "Goodwill impairment." WOSEA is part of our Contracting Services segment.

At December 31, 2012, our remaining intangible assets, other than goodwill, was $1.7 million ($0.5 million, net of accumulated amortization of $1.2 million) for intellectual property and patented technology related to our well intervention operations. Total amortization expenses for intangible assets was $0.1 million for each of the years ended December 31, 2012, 2011, and 2010. We expect to record approximately $0.1 million of amortization expense related to our remaining unamortized intangible assets for each of the next four years.

Recertification Costs and Deferred Dry Dock Charges

Our contracting services vessels are required by regulation to be recertified after certain periods of time. Recertification costs are incurred while a vessel is in dry dock. In addition, routine repairs and maintenance are performed and at times, major replacements and improvements are performed. We expense routine repairs and maintenance costs as they are incurred. We defer and amortize dry dock and related recertification costs over the length of time for which we expect to receive benefits from the dry dock and related recertification, which is generally 30 months but can be as long as 60 months if the appropriate permitting is obtained. Vessels are typically available to earn revenue for the period between dry dock and related recertification processes. A dry dock and related recertification process typically lasts one to two months, a period during which the vessel is not available to earn revenue. Major replacements and improvements that extend the vessel's economic useful life or functional operating capability are capitalized and depreciated over the vessel's remaining economic useful life.

As of December 31, 2012 and 2011, capitalized deferred dry dock charges included within "Other assets, net" in the accompanying consolidated balance sheets (Note 4) totaled $22.7 million and $5.4 million, respectively. The increase in our deferred dry dock costs in 2012 was associated with extended regulatory dry docks of the Q4000, Seawell and Well Enhancer well intervention vessels. During the years ended December 31, 2012, 2011 and 2010, dry dock amortization expense was $8.6 million, $7.6 million and $6.9 million, respectively.

Convertible Preferred Stock

In December 2012, the holder of the remaining $1 million of Convertible Preferred Stock converted it into 361,402 shares of our common stock. We had previously presented the Convertible Preferred Stock below liabilities but not as a component of shareholders' equity, because we were, under certain instances, required to settle any future conversions in cash. The dividend rate was 4% for 2012, 2011 and 2010. In

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May 2010, the holder converted $5 million of its Convertible Preferred stock into 1,807,011 shares of our common stock. Our Convertible Preferred Stock was assessed for inclusion in our diluted earnings per share calculation using the if converted method (see "Earnings Per Share") below.

Revenue Recognition

Revenues from contracting services are derived from contracts, which are both short-term and long-term in duration. Our long-term contracting services contracts are contracts that contain either lump-sum, turnkey provisions or provisions for specific time, material and equipment charges, which are billed in accordance with the terms of such contracts. We recognize revenue as it is earned at estimated collectible amounts. Further, we record revenues net of taxes collected from customers and remitted to governmental authorities.

Unbilled revenue represents revenue attributable to work completed prior to period end that has not yet been invoiced. All amounts included in unbilled revenue at December 31, 2012 and 2011 are expected to be billed and collected within one year.

Dayrate Contracts. Revenues generated from specific time, materials and equipment contracts are generally earned on a dayrate basis and recognized as amounts are earned in accordance with contract terms. In connection with these contracts, we may receive revenues for mobilization of equipment and personnel. Revenues related to mobilization are deferred and recognized over the period in which contracted services are performed using the straight-line method. Incremental costs incurred directly for mobilization of equipment and personnel to the contracted site, which typically consist of materials, supplies and transit costs, are also deferred and recognized over the period in which contracted services are performed using the straight-line method. Our policy to amortize the revenues and costs related to mobilization on a straight-line basis over the estimated contract service period is consistent with the general pace of activity, level of services being provided and dayrates being earned over the service period of the contract. Mobilization costs to move vessels when a contract does not exist are expensed as incurred.

Turnkey Contracts. Revenue on significant turnkey contracts is recognized on the percentage-of-completion method based on the ratio of costs incurred to total estimated costs at completion. In determining whether a contract should be accounted for using the percentage-of-completion method, we consider whether:

- the customer provides specifications for the construction of facilities or for the provision of related services;
- we can reasonably estimate our progress towards completion and our costs;
- the contract includes provisions as to the enforceable rights regarding the goods or services to be provided, consideration to be received, and the manner and terms of payment;
- the customer can be expected to satisfy its obligations under the contract; and
- we can be expected to perform our contractual obligations.

Under the percentage-of-completion method, we recognize estimated contract revenue based on costs incurred to date as a percentage of total estimated costs. Changes in the expected cost of materials and labor, productivity, scheduling and other factors affect the total estimated costs. Additionally, external factors, including weather and other factors outside of our control, may also affect the progress and estimated cost of a project's completion and, therefore, the timing of income and revenue recognition. We routinely review estimates related to our contracts and reflect revisions to profitability in earnings on a current basis. If a current estimate of total contract cost indicates an ultimate loss on a contract, we recognize the projected loss in full when it is first determined. We recognize additional contract revenue related to claims when the claim is probable and legally enforceable.

Whenever we have a contract that qualifies as a loss contract, we estimate the future shortfall between our anticipated future revenues and future costs. See Note 13 for information regarding our more significant loss contracts during the three-year period ended December 31, 2012.

Income Taxes

Deferred income taxes are based on the differences between financial reporting and tax bases of assets and liabilities. We utilize the liability method of computing deferred income taxes. The liability

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method is based on the amount of current and future taxes payable using tax rates and laws in effect at the balance sheet date. Income taxes have been provided based upon the tax laws and rates in the countries in which operations are conducted and income is earned. A valuation allowance for deferred tax assets is recorded when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. We consider the undistributed earnings of our principal non-U.S. subsidiaries to be permanently reinvested.

It is our policy to provide for uncertain tax positions and the related interest and penalties based upon management's assessment of whether a tax benefit is more likely than not to be sustained upon examination by tax authorities. At December 31, 2012, we believe we have appropriately accounted for any unrecognized tax benefits. To the extent we prevail in matters for which a liability for an unrecognized tax benefit is established or are required to pay amounts in excess of the liability, our effective tax rate in a given financial statement period may be affected.

Foreign Currency

Because we operate in various regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar (primarily with respect to Helix Well Ops (U.K.) Limited ("WOUK")). The functional currency for WOUK is the applicable local currency (British Pound). Previously, WOSEA also had currency risk as its functional currency was the applicable local currency (Australian Dollar). We ceased operations in Australia in 2012. Results of operations for these subsidiaries are translated into U.S. dollars using average exchange rates during the period. Assets and liabilities of these foreign subsidiaries are translated into U.S. dollars using the exchange rate in effect at December 31, 2012 and 2011 and the resulting translation adjustment, which was an unrealized gain (loss) of $7.3 million and $(1.0) million, respectively, is included in accumulated other comprehensive income (loss), a component of shareholders' equity. All foreign currency transaction gains and losses are recognized currently in the consolidated statements of operations.

Our foreign currency gains (losses) totaled $(0.5) million in 2012, $(2.1) million in 2011 and $1.9 million in 2010. These realized amounts are exclusive of any unrealized gains or losses from our foreign currency exchange derivative contracts.

Derivative Instruments and Hedging Activities

Our continuing operations are exposed to market risks associated with interest rates and foreign currency exchange rates. Our risk management activities involve the use of derivative financial instruments to hedge the impact of market risk exposure related to variable interest rates and foreign currency exchange rates. All derivatives are reflected in our balance sheet at fair value, unless otherwise noted.

We formally document all relationships between hedging instruments and the related hedged items, as well as our risk management objectives, strategies for undertaking various hedge transactions and our methods for assessing and testing correlation and hedge ineffectiveness. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows of the hedged items. We discontinue hedge accounting if we determine that a derivative is no longer highly effective as a hedge, or it is probable that a hedged transaction will not occur. If hedge accounting is discontinued because it is probable the hedged transaction will not occur, deferred gains or losses on the hedging instruments are recognized in earnings immediately. If the forecasted transaction continues to be probable of occurring, any deferred gains or losses in accumulated other comprehensive income (loss) are amortized to earnings over the remaining period of the original forecasted transaction.

We engage solely in cash flow hedges. Hedges of cash flow exposure are entered into to hedge a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability. Changes in the derivative fair values that are designated as cash flow hedges are deferred to the extent that they are effective and are recorded as a component of accumulated other comprehensive income or loss (a component of shareholders' equity) until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge's change in fair value is recognized immediately in earnings. In addition, any change in the fair value of a derivative that does not qualify for hedge accounting is recorded in earnings in the period in which the change occurs.

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Interest Rate Risk

As some of our long-term debt has variable interest rates and therefore is subject to market influences, in January 2010 we entered into various interest rate swaps to stabilize cash flows relating to interest payments for $200 million of our Term Loan debt under our Credit Agreement (Note 7). The last of these monthly contracts matured in January 2012. In August 2011, we entered into additional interest rate swap contracts to fix the interest rate on $200 million of our Term Loan debt. These monthly contracts began in January 2012 and extend through January 2014. Changes in the fair value of an interest rate swap are deferred to the extent the swap is effective. These changes are recorded as a component of accumulated other comprehensive income (loss) until the anticipated interest payments occur and are recognized in interest expense. The ineffective portion of the interest rate swap, if any, is recognized immediately in earnings within the line titled "Net interest expense." The amount of ineffectiveness associated with our interest rate swap contracts was immaterial in 2011 and 2010.

Under the terms of our Credit Agreement, we are required to use at a minimum 60% of the after-tax proceeds from the sales of the Caesar, the Express and ERT to make payments to reduce our Term Loan debt and borrowings under the Revolving Credit Facility. Because it was probable that we would pay off the Term Loan debt before the expiration of our interest rate swaps, we concluded that the swaps no longer qualified as cash flow hedges in December 2012. At December 31, 2012, we recorded losses of approximately $0.6 million ($0.4 million net of tax) to reflect the mark-to-market adjustments for changes in the fair values of the interest rate swaps. We settled all of our remaining interest rate swap contracts for $0.6 million in February 2013.

Foreign Currency Exchange Rate Risk

Because we operate in various regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar. We entered into various foreign currency forwards to stabilize expected cash outflows relating to certain vessel charters that are denominated in British pounds. The aggregate fair value of the foreign currency forwards was a net asset of $0.1 million at December 31, 2012 and a net liability of $0.1 million at December 31, 2011. All of our remaining foreign exchange contracts are not accounted for as hedge contracts and changes in their fair value are being marked-to-market each reporting period. We recorded gains (losses) totaling $0.4 million in 2012, $0.2 million in 2011 and $(2.6) million in 2010 associated with foreign exchange contracts not qualifying for hedge accounting.

In January 2013, we entered into foreign currency exchange contracts to hedge the foreign currency exposure to potential variability in cash flows associated with Grand Canyon charter payments ($104.6 million) denominated in Norwegian Kroner (NOK591.3 million), through September 2017. These contracts currently qualify for hedge accounting treatment.

See Note 17 for more information regarding the accounting for our derivative contracts including our commodity contracts associated with ERT.

Earnings Per Share

We have shares of restricted stock issued and outstanding, some of which remain subject to vesting requirements. Holders of such shares of unvested restricted stock are entitled to the same liquidation and dividend rights as the holders of our outstanding common stock and are thus considered participating securities. Under applicable accounting guidance, the undistributed earnings for each period are allocated based on the participation rights of both the common shareholders and holders of any participating securities as if earnings for the respective periods had been distributed. Because both the liquidation and dividend rights are identical, the undistributed earnings are allocated on a proportionate basis. Further, we are required to compute earnings per share ("EPS") amounts under the two class method in periods in which we have earnings from continuing operations. For periods in which we have a net loss we do not use the two class method as holders of our restricted shares are not contractually obligated to share in such losses.

The presentation of basic EPS amounts on the face of the accompanying consolidated statements of operations is computed by dividing the net income applicable to Helix common shareholders by the weighted average shares of outstanding common stock. The calculation of diluted EPS is similar to basic EPS, except that the denominator includes dilutive common stock equivalents and the income included in the numerator

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excludes the effects of the impact of dilutive common stock equivalents, if any. The computations of the numerator (Income) and denominator (Shares) to derive the basic and diluted EPS amounts presented on the face of the accompanying consolidated statements of operations for the years ended December 31, 2012, 2011 and 2010 are as follows (in thousands):

	Year Ended December 31,					
	2012		2011		2010	
	Income	Shares	Income	Shares	Income	Shares
Basic:						
Net income (loss) applicable to Helix common shareholders	$(46,334)		$129,939		$(127,102)	
Less: Undistributed net income allocable to participating securities	—		(1,599)		—	
Undistributed net income (loss) applicable to common shareholders	(46,334)		128,340		(127,102)	
Less: (Income) loss from discontinued operations, net of tax	(23,684)		(95,221)		106,657	
Add: Undistributed net income from discontinued operations allocable to participating securities	—		1,172		—	
Income (loss) from continuing operations applicable to Helix common shareholders	$(70,018)	104,449	$34,291	104,528	$(20,445)	103,857
Diluted:						
Income (loss) from continuing operations applicable to Helix common shareholders - Basic	$(70,018)	104,449	$34,291	104,528	$(20,445)	103,857
Effect of dilutive securities:						
Share-based awards other than participating securities	—	—	—	64	—	—
Undistributed net income reallocated to participating securities	—	—	2	—	—	—
Convertible preferred stock	—	—	40	361	—	—
Income (loss) from continuing operations applicable to Helix common shareholders - Diluted	(70,018)		34,333		(20,445)	
Income (loss) from discontinued operations, net of tax	23,684		95,221		(106,657)	
Net income (loss) applicable to Helix common shareholders - Diluted	$(46,334)	104,449	$129,554	104,953	$(127,102)	103,857

We had net losses from continuing operations for the years ended December 31, 2012 and 2010. Accordingly, our diluted EPS calculation for 2012 and 2010 was equivalent to our basic EPS calculation because it excluded any assumed exercise or conversion of common stock equivalents because they were deemed to be anti-dilutive, meaning their inclusion would have reduced the reported net loss per share in those respective years. Shares that otherwise would have been included in the diluted per share calculations for the year ended December 31, 2012 and 2010, assuming we had earnings from continuing operations, are as follows (in thousands):

	2012	2010
Diluted shares (as reported)	104,449	103,857
Share-based awards	382	466
Convertible preferred stock	334	1,015
Total	105,165	105,338

The diluted EPS calculation also excluded dividends and related costs associated with the convertible preferred stock that otherwise would have been added back to net income if assumed conversion of the shares was dilutive during the year.

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There were no diluted shares associated with our 2025 Convertible Senior Notes as the conversion price of $32.14 (and conversion trigger of $38.57 per share) was not met in any of the years ended December 31, 2012, 2011 and 2010. Also, no diluted shares were included for our 2032 Notes for the year ended December 31, 2012 as the conversion price of $25.02 (and conversion trigger of $32.53 per share) was not met, and because we have the right to settle any such future conversions in cash at our sole discretion (Note 7).

Major Customers and Concentration of Credit Risk

The market for our products and services is primarily the offshore oil and gas industry. Oil and gas companies spend capital on exploration, drilling and production operations, the amount of which is generally dependent on the prevailing view of future oil and gas prices that are subject to many external factors which may contribute to significant volatility. Our customers consist primarily of major oil and gas companies, well-established oil and gas pipeline companies and independent oil and gas producers and suppliers. We perform ongoing credit evaluations of our customers and provide allowances for probable credit losses when necessary. The percent of consolidated revenue from major customers, those whose total represented 10% or more of our consolidated revenues from continuing operations is as follows: 2012 — Shell (12%); 2011 — Shell (10%) and 2010 — BP plc. (26%). The percent of revenue from major customers, those whose total represented 10% or more of our discontinued oil and gas revenues, is as follows: 2012 — Shell (64%) and JP Morgan Ventures (26%); 2011 — Shell (89%); and 2010 — Shell (67%) and Louis Dreyfus Energy Services (19%). We estimate that in 2012 we provided subsea services to over 70 customers.

Fair Value Measurements

Current fair value accounting standards define fair value, establish a consistent framework for measuring fair value and expand disclosure for each major asset and liability category measured at fair value on either a recurring or nonrecurring basis. These standards also clarify that fair value is an exit price, representing the amount that would be received to sell an asset, or paid to transfer a liability, in an orderly transaction between market participants. These fair value accounting rules establish a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value as follows:

- Level 1. Observable inputs such as quoted prices in active markets;
- Level 2. Inputs, other than the quoted prices in active markets, that are observable either directly or indirectly; and
- Level 3. Unobservable inputs for which there is little or no market data, which require the reporting entity to develop its own assumptions.

Assets and liabilities measured at fair value are based on one or more of three valuation techniques as follows:

(a) Market Approach. Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.
(b) Cost Approach. Amount that would be required to replace the service capacity of an asset (replacement cost).
(c) Income Approach. Techniques to convert expected future cash flows to a single present amount based on market expectations (including present value techniques, option-pricing and excess earnings models).

Our financial instruments include cash and cash equivalents, accounts receivable, accounts payable, our long-term debt and various derivative instruments. The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to the highly liquid nature of these instruments. The following table provides additional information related to other financial instruments measured at fair value on a recurring basis at December 31, 2012 (in thousands):

	Level 1	Level 2 (1)	Level 3	Total	Valuation Technique
Assets:					
Oil contracts	$ —	$ 5,800	$ —	$ 5,800	(c)
Foreign currency forwards	—	146	—	146	(c)

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	Level 1	Level 2 (1)	Level 3	Total	Valuation Technique
Liabilities:					
Oil contracts	—	15,777	—	15,777	(c)
Fair value of long-term debt (2)	994,311	123,187	—	1,117,498	(a)
Interest rate swaps	—	521	—	521	(c)
Total net liability	$ 994,311	$ 133,539	$ —	$ 1,127,850	

(1) Unless otherwise indicated, the fair value of our Level 2 derivative instruments reflects our best estimate and is based upon exchange or over-the-counter quotations whenever they are available. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, we utilize other valuation techniques or models to estimate market values. These modeling techniques require us to make estimations of future prices, price correlation and market volatility and liquidity based on market data. Our actual results may differ from our estimates, and these differences could be positive or negative.

(2) See Note 7 for additional information regarding our long-term debt. The fair value of our long-term debt at December 31, 2012 and 2011 is as follows:

	2012		2011	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Term Loans (mature July 2015) (a)	$367,181	$368,295	$279,750	$279,750
Revolving Credit Facility (matures July 2015) (a)	100,000	100,000	—	—
2025 Notes (mature December 2025) (b)	3,487	3,487	300,000	300,543
2032 Notes (mature March 2032) (c)	200,000	239,320	—	—
Senior Unsecured Notes (mature January 2016)	274,960	283,209	474,960	501,083
MARAD Debt (matures February 2027) (d)	105,288	123,187	110,166	124,488
Total debt	$1,050,916	$1,117,498	$1,164,876	$1,205,864

(a) In February 2013, we repaid $293.9 million of our Term Loans and $24.5 million under our Revolving Credit Facility with the after-tax proceeds from the sale of ERT.

(b) Carrying value excludes the related unamortized debt discount of $9.6 million at December 31, 2011. This remaining amount was repurchased by us in February 2013.

(c) Carrying value excludes the related unamortized debt discount of $31.7 million at December 31, 2012.

(d) The estimated fair value of all debt, other than the MARAD debt, was determined using Level 1 inputs using the market approach. The fair value of the MARAD debt was determined using a third party evaluation of the remaining average life and outstanding principal balance of the MARAD indebtedness as compared to other governmental obligations in the marketplace with similar terms. The fair value of the MARAD Debt was estimated using Level 2 fair value inputs using the market approach.

We review long-lived assets for impairment whenever events occur or changes in circumstances indicate that the carrying amount of assets may not be recoverable. In such evaluation, the estimated future undiscounted cash flows to be generated by the asset are compared with the carrying value of the asset to determine if an impairment may be required. For our former oil and gas properties, the estimated future undiscounted cash flows are based on estimated crude oil and natural gas proved and probable reserves and published future market commodity prices, estimated operating costs and estimates of future capital expenditures. If the estimated undiscounted cash flows for a particular asset are not sufficient to cover the asset's carrying value, it is impaired and the carrying value is reduced to the asset's current fair value. The fair value of these assets is determined using an income approach by calculating the present value of future cash flows attributable to the asset based on market information (such as forward commodity prices), estimates of future costs and estimated proved and probable reserve quantities. These fair value measurements fall within Level 3 of the fair value hierarchy.

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Debt Discount

On January 1, 2009, we recorded a discount of $60.2 million related to our Convertible Senior Notes due 2025 ("2025 Notes") as required. To arrive at this discount amount, we estimated the fair value of the liability component of the 2025 Notes as of the date of their issuance (March 30, 2005) using an income approach. To determine this estimated fair value, we used borrowing rates of similar market transactions involving comparable liabilities at the time of issuance and an expected life of 7.75 years, which represented the earliest period that the holders could require us to repurchase the 2025 Notes (Note 7). The discount related to our 2025 Notes became fully amortized in December 2012.

In connection with the issuance of our Convertible Senior Notes due 2032 ("2032 Notes"), we recorded a discount of $35.4 million under existing accounting requirements. To arrive at this discount amount, we estimated the fair value of the liability component of the 2032 Notes as of the date of their issuance (March 12, 2012) using an income approach. To determine this estimated fair value, we used borrowing rates of similar market transactions involving comparable liabilities at the time of issuance and an expected life of 6.0 years. In selecting the expected life, we selected the earliest date that the holders could require us to repurchase all or a portion of the 2032 Notes (March 15, 2018). The remaining unamortized amount of the discount of the 2032 Notes was $31.7 million at December 31, 2012 (Note 7).

Investment Available for Sale

In 2009 we sold substantially all of our owned shares of the publicly-traded Cal Dive common stock for net proceeds of $418.2 million, net of underwriting fees. Following these sale transactions, we owned 0.5 million shares of Cal Dive common stock, representing less than 1% of the total outstanding shares of Cal Dive. Accordingly we classified our remaining interest in Cal Dive as an investment available for sale. As an investment available for sale, the value of our remaining interest was marked-to-market at each period end with the corresponding change in value being reported as a component of accumulated other comprehensive income (loss) in the accompanying consolidated balance sheet. In 2010, we recorded a $2.2 million non-cash other than temporary impairment charge that reflected the substantial reduction in Cal Dive's common stock price since our sale of shares of Cal Dive common stock in 2009. In March 2011, we sold our remaining 0.5 million shares of Cal Dive common stock on the open market for gross proceeds of $3.6 million resulting in a pre-tax gain of $0.8 million.

New Accounting Standards

In December 2011, the FASB issued ASU No. 2011-11, "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities" ("ASU 2011-11"). Offsetting, otherwise known as netting, is the presentation of assets and liabilities as a single net amount in the statement of financial position (balance sheet). U.S. GAAP allows companies the option to present net in their balance sheets derivatives that are subject to a legally enforceable netting arrangement with the same party where rights of set-off are only available in the event of default or bankruptcy. ASU 2011-11 requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. An entity is required to apply the amendments for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. An entity should provide the disclosures required by those amendments retrospectively for all comparative periods presented. We are currently assessing the impact of ASU 2011-11 on our consolidated financial statements.

Note 3 — Oil and Gas Properties

Discontinued Operations

In December 2012, we announced a definitive agreement for the sale of ERT. On February 6, 2013, we sold ERT for $620 million plus contingent consideration in the form of overriding royalty interests in the Wang well and certain other future exploration prospects. As a result, we have presented the assets and liabilities included in the sale of ERT and the historical operating results of our former Oil and Gas segment as discontinued operations in the accompanying consolidated financial statements.

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Oil and Gas Significant Accounting Policies

Restricted Cash

We had restricted cash totaling $28.4 million at December 31, 2012 and $33.7 million at December 31, 2011, all of which consisted of funds required to be escrowed to cover the future asset retirement obligations associated with the South Marsh Island Block 130 field. These escrowed funds were included in the sale of ERT in February 2013. These amounts are reflected in "Non-current assets of discontinued operations" in the accompanying consolidated balance sheets.

Inventories

We had oil and gas inventory totaling $11.9 million at December 31, 2012 and $16.4 million at December 31, 2011. This inventory primarily represents the cost of supplies to be used in our oil and gas drilling and development activities, primarily drilling pipe, tubulars and certain wellhead equipment, including two subsea trees. Our inventories are stated at the lower of cost or market value and we utilize the average cost method of maintaining our inventory. There were no charges to reduce inventory to its lower cost or market value in 2012. In December 2011, we agreed to sell approximately $4.6 million of our drilling pipe inventory for $2.5 million. In connection with this sale, we recorded a $2.1 million loss to reduce its value to its expected realized value at December 31, 2011.

Property and Equipment

Depreciation and Depletion. Depletion expense for oil and gas properties is determined on a field-by-field basis using the units-of-production method, with depletion rates for leasehold acquisition costs based on estimated total remaining proved reserves. Depletion rates for well and related facility costs are based on estimated total remaining proved developed reserves associated with each individual field. The depletion rates are changed whenever there is an indication of the need for a revision, but at a minimum, are evaluated annually. Any such revisions are accounted for prospectively as a change in accounting estimate. Depletion was discontinued when we announced the sale of ERT. We depreciate our other property and equipment over its estimated useful life on a straight-line basis.

Oil and Gas Properties. All of our former oil and gas properties are located in the United States offshore in the Gulf of Mexico. We followed the successful efforts method of accounting for our oil and natural gas exploration and development activities. Under this method, the costs of successful wells and leases containing productive reserves are capitalized. Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized and are reflected as a reduction of investing cash flows in the accompanying consolidated statements of cash flows.

Proved Properties. Proved oil and gas properties are assessed for possible impairment at least annually or when events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. An impairment loss is recognized as a result of a triggering event and when the estimated undiscounted future cash flows from a property are less than the carrying value. If impairment is indicated, an impairment charge is recorded equal to the difference between the carrying amount and the fair value of the property based on discounted future cash flows. In the discounted cash flow method, estimated future cash flows are based on prices based on published forward commodity price curves as of the date of the estimate and management's estimates of future operating and development costs and a risk adjusted discount rate. See "Impairments" below for additional information regarding our oil and gas property impairments.

Unproved Properties. Unproved properties are also periodically assessed for impairment based on exploration and drilling efforts to date on the individual prospects and lease expiration dates. The amounts and timing of impairment provisions are also impacted by management's assessment of the results of exploration activities, availability of funds for future activities and the current and projected political climate in areas in which we operate. We recorded impairments to unproved oil and gas properties totaling $0.8 million in 2012, $8.3 million in 2011 and $6.4 million in 2010. Such impairments were included in exploration expenses.

Exploratory Costs. The costs of drilling an exploratory well are capitalized as uncompleted or "suspended" wells pending the determination of whether the well has found proved reserves. If proved reserves are found these costs remain capitalized; if no reserves are found the capitalized costs are charged to exploration expenses. See “Exploration and Other” below for additional information regarding our exploration costs.

Accounting for Asset Retirement Obligations

We are required to record our asset retirement obligations at fair value in the period such obligations are incurred. The associated asset retirement costs are capitalized as part of the carrying cost of the asset. Our asset retirement obligations consisted of estimated costs for dismantlement, removal, site reclamation and similar activities associated with our former oil and gas properties. An asset retirement obligation and the related asset retirement cost are recorded when an asset is first constructed or purchased. The asset retirement cost is determined and discounted to present value using a credit-adjusted risk-free rate. After the initial recording, the liability is increased for the passage of time, with the increase being reflected as accretion expense, which is a component of our depreciation, depletion and amortization expense.

The following table describes the changes in our asset retirement obligations for ERT (both current and long-term) for the years ended December 31, 2012 and 2011 (in thousands):

	2012	2011
Asset retirement obligations at January 1,	$227,090	$222,653
Liability incurred during the period	3,664	4,982
Liability settled during the period	(105,160)	(37,769)
Other revisions in estimated cash flows (1)	62,834	22,345
Accretion expense (included in depreciation and amortization)	12,550	14,879
Asset retirement obligations at December 31,	$200,978	$227,090

(1) The increased amount of these liabilities includes revisions to both non-producing and producing oil and gas properties. Increases to liabilities associated with non-producing fields ($12.4 million and $22.5 million during the year ended December 31, 2012 and 2011, respectively) include corresponding abandonment expense charges to cost of sales within our consolidated statements of operations while changes in estimates for producing properties are recorded as an increase to property and equipment carrying costs of the related oil and gas properties within our consolidated balance sheets.

Revenue Recognition

Revenues from sales of crude oil and natural gas are recorded when delivery to the customer has occurred, title has transferred, prices are fixed and determinable and collection is reasonably assured. This occurs when production has been delivered to a pipeline or when a barge lifting has occurred. We may have an interest with other producers in certain properties. In this case, the entitlements method is used to account for sales of production. Under the entitlements method, we may receive more or less than our entitled share of production. If more than our entitled share of production is received, the imbalance is treated as a liability. If less than our entitled share is received, the imbalance is recorded as an asset. As of December 31, 2012, the net imbalance was a $1.0 million asset and was included in “Current assets of discontinued operations” ($4.0 million) and “Current liabilities of discontinued operations” ($3.0 million).

Derivative Instruments and Hedging Activities

As previously noted, our risk management activities often involve the use of derivative financial instruments to hedge the impact of market risk exposure, including those related to the market prices of oil and natural gas. To reduce the impact of these risks on earnings and increase the predictability of our cash flows, from time to time we have entered into certain derivative contracts, including costless collars and swaps for a portion of our oil and gas production. These derivative contracts are reflected in our balance sheet at fair value. See Note 2 for additional disclosure regarding our accounting for derivative contracts.

The fair value of our oil and gas derivative contracts reflects our best estimate and is based upon exchange or over-the-counter quotations whenever they are available. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, we utilize other valuation techniques or models to estimate market values.

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These modeling techniques require us to make estimates of future prices, price correlation and market volatility and liquidity. Our actual results may differ from our estimates, and these differences can be positive or negative.

Prior to the announcement of the sale of ERT in December 2012, all of the effect of our oil and gas hedging contracts were reflected as a component of our discontinued operations in the accompanying consolidated financial statements. As a result of the announcement of the sale of ERT, we de-designated all of our remaining oil and natural gas derivative contracts as hedging instruments. Because the hedging contracts were not part of the sale of ERT, the effect post announcement of the sale are included within continuing operations in the accompanying consolidated financial statements.

At December 31, 2012, all of our commodity derivative contracts were subject to mark-to-market adjustments to reflect the changes in their fair values. In connection with the de-designation of these derivative contracts as hedging instruments, we were required to recognize amounts previously recorded in accumulated other comprehensive income (loss) and related deferred taxes into earnings. At December 31, 2012, we recorded losses of approximately $10.5 million ($6.8 million net of tax) to reflect the mark-to-market adjustments for changes in the fair values of the oil and gas commodity derivative contracts. See Note 17 for additional information regarding our commodity derivative contracts.

Impairments

Proved property impairment charges are reflected as reductions in cost of sales in our discontinued operations. We had no oil and gas proved property impairment charges in 2012.

In December 2012, following the announcement of our intention to sell ERT, we recorded a $138.6 million impairment charge to reduce our carrying value of ERT to its estimated fair value less costs to sell as determined by the negotiated sales price for ERT.

In 2011, we recorded $90.9 million of oil and gas property impairment charges associated with 11 of our Gulf of Mexico oil and gas fields. These impairment charges were primarily related to changes in the field economics of the affected oil and gas properties. During 2011, the price of natural gas decreased significantly. When natural gas prices decrease this often affects the assumptions regarding future development of certain fields as some or all of those proved reserves may become uneconomic to develop or produce. Our impairment charges also reflect end of field life factors, including premature depletion or capital allocation decisions, primarily those affecting third party operated fields.

In 2010, we recorded $176.7 million of oil and gas property impairment charges, including $4.1 million related to our one U.K. oil and gas property which is reflected in continuing operations as it was not included in the sale of ERT. A total of 21 of our former Gulf of Mexico oil and gas properties were affected by impairment charges in 2010. The impairment charges associated with producing fields totaled $172.6 million, which primarily reflected reduction in our estimates of proved reserves (Note 16).

Results of Discontinued Operations

The following summarized financial information relates to ERT, which is reported as “Income (loss) from discontinued operations, net of tax” in the accompanying consolidated statements of operations:

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	Year Ended December 31,		
	2012	2011	2010
Revenues	$557,231	$696,607	$425,369
Costs:			
Production (lifting) costs	164,663	176,269	131,156
Hurricane repair expense	662	(4,838)	4,699
Exploration expenses (1)	3,295	10,914	8,276
Depreciation, depletion, amortization and accretion	158,284	219,915	235,243
Proved property impairment and abandonment charges (2)	151,045	113,439	177,138
(Gain) loss on sale of oil and gas properties	1,714	(4,531)	(287)
Non-hedge gain on commodity derivative contracts	(5,550)	—	(1,088)
Selling, general and administrative expenses	17,823	12,951	15,966
Net interest expense and other (3)	28,191	25,558	19,687
Total costs	520,127	549,677	590,790
Pretax income (loss) from discontinued operations	37,104	146,930	(165,421)
Income tax provision (benefit)	13,420	51,709	(58,764)
Income (loss) from discontinued operations, net of tax	$23,684	$95,221	$(106,657)

(1) See "Exploration and Other" below for additional information related to the components of our exploration costs, including impairment charges for expiring unproved leases.

(2) Includes $138.6 million recorded to reduce our carrying value of ERT to its estimated fair value less costs to sell.

(3) Net interest expense of $27.7 million, $25.2 million and $19.7 million for the years ended December 31, 2012, 2011 and 2010, respectively, was allocated to ERT primarily based on interest associated with indebtedness directly attributed to the substantial acquisition made by our oil and gas subsidiary in 2006. This includes interest related to debt required to be paid upon the disposition of ERT.

Included in the accompanying consolidated balance sheets are the following major classes of assets and liabilities associated with ERT as of December 31, 2012 and 2011:

	2012	2011
Cash and cash equivalents	$2	$2
Accounts receivable	63,762	90,882
Other current assets	20,236	28,037
Current assets of discontinued operations	84,000	118,921
Property and equipment, net	787,852	871,658
Restricted cash and other	28,375	33,741
Non-current assets of discontinued operations	$816,227	$905,399
Accounts payable	$110,569	$73,124
Accrued liabilities	18,217	27,968
Current asset retirement obligations	53,741	65,883
Current liabilities of discontinued operations	182,527	166,975
Asset retirement obligations	147,237	161,208
Non-current liabilities of discontinued operations	$147,237	$161,208

Exploration and Other

As of December 31, 2012, we had $8.2 million of capitalized costs associated with ongoing exploration and/or appraisal activities. The following table provides a detail of our capitalized exploratory project costs at December 31, 2012 and 2011 (in thousands):

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	2012	2011
Wang (1)	$ —	$ 3,096
Danny II	—	2,619
T-6 (1)	8,122	—
Other	125	125
Total	$ 8,247	$ 5,840

(1) Both of these wells are located within the Phoenix field at Green Canyon Block 237.

The following table reflects net changes in exploratory well costs during the years ended December 31, 2012, 2011 and 2010 (in thousands):

	2012	2011	2010
Beginning balance at January 1,	$5,840	$3,252	$3,059
Additions pending the determination of proved reserves	135,311	2,513	(944)
Reclassifications to proved properties	(132,959)	5	713
Charged to dry hole expense	55	70	424
Ending balance at December 31,	$8,247	$5,840	$3,252

Further, the following table details the components of exploration expenses for the years ended December 31, 2012, 2011 and 2010 (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Delay rental and geological and geophysical costs	$2,517	$2,650	$2,306
Impairment of unproved properties	833	8,334	6,394
Dry hole expense	(55)	(70)	(424)
Total exploration expense	$3,295	$10,914	$8,276

Our oil and gas activities in the United States are regulated by the federal government and require significant third-party involvement, such as refinery processing and pipeline transportation. We record revenue from our offshore properties net of royalties paid to the Office of Natural Resources Revenue. Royalty fees paid totaled approximately $78.1 million, $85.4 million and $37.2 million for the years ended December 31, 2012, 2011 and 2010, respectively.

United Kingdom Property

Since 2006, we have maintained an ownership interest in the Camelot field, located offshore in the North Sea. In 2007, we sold half of our 100% working interest in Camelot to a third party with whom we agreed to jointly pursue future development and production of the field. In February 2010, we acquired this third party thereby assuming its obligations, most notably the asset retirement obligation, related to its 50% working interest in the field.

In connection with the valuation of assets acquired and liabilities assumed in this acquisition, we reassessed the fair value associated with our original 50% interest in the field. Based on these evaluations, it was concluded that an impairment of the property was required based on the unlikely probability of our spending the future capital necessary to further develop the Camelot field. In 2010, we recorded $4.1 million of impairment charges to fully impair the property and $0.9 million of charges to expense to increase the asset retirement obligation for the Camelot field.

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Our plan was to fully abandon the field in 2012 in accordance with applicable regulations in the United Kingdom. Modifications to U.K. regulations governing such operations required us to reassess our existing abandonment plan and cost estimates in 2011. The results of this review concluded that the scope of work to be performed in the abandoning of the wells in the field would be significantly expanded and as a result our cost estimates significantly increased. Based on our abandonment plan, we increased the asset retirement obligation by recording a corresponding $20.0 million charge to expense. At December 31, 2011, the remaining asset retirement obligation for the Camelot field was $27.3 million.

During 2012, we recorded $15.5 million of additional charges to expense to reflect further increases in our estimated costs to complete our abandonment activities at Camelot, including the removal of certain environmentally sensitive materials. The abandonment of the Camelot field is substantially complete. At December 31, 2012, the recorded asset retirement obligation for the Camelot field was $2.9 million.

The operating results and financial position associated with our U.K. property do not qualify for discontinued operations accounting treatment as this property was not classified as held for sale and thus they are reflected as continuing operations in our consolidated financial statements for all periods presented.

Note 4 — Details of Certain Accounts

Other current assets consisted of the following as of December 31, 2012 and 2011 (in thousands):

	2012	2011
Other receivables	$1,086	$618
Prepaid insurance	11,999	12,608
Other prepaids	11,751	11,328
Spare parts inventory	2,480	1,677
Income tax receivable (1)	14,201	—
Current deferred tax assets	43,942	41,449
Derivative assets	5,946	21,579
Other	5,529	4,325
Total other current assets	$96,934	$93,584

(1) Reflects the total amount of estimated tax receivable in excess of the estimated current income tax liability.

Other assets, net, consisted of the following as of December 31, 2012 and 2011 (in thousands):

	2012	2011
Deferred dry dock expenses, net (1)	$22,704	$5,381
Deferred financing costs, net	24,338	26,483
Intangible assets with finite lives, net	491	531
Other	2,304	2,771
Total other assets, net	$49,837	$35,166

(1) The increase subsequent to December 31, 2011 reflects the costs associated with the regulatory dry docks for our Q4000, Seawell and Well Enhancer vessels during 2012.

Accrued liabilities consisted of the following as of December 31, 2012 and 2011 (in thousands):

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	2012	2011
Accrued payroll and related benefits	$51,561	$45,217
Current asset retirement obligations (1)	2,898	27,300
Unearned revenue	6,137	7,654
Billing in excess of cost (2)	6,445	28,839
Accrued interest	17,451	24,028
Derivative liability (3)	16,266	1,247
Taxes payable excluding income tax payable	5,164	3,748
Pipelay assets sale deposit (4)	50,000	—
Other	5,592	8,079
Total accrued liabilities	$161,514	$146,112

(1) Reflects the substantial completion of the abandonment of the Camelot field (Note 3).

(2) Decrease reflects fewer ongoing subsea construction projects using the percentage-of-completion method of accounting as a result of the expected sales of our remaining pipelay vessels.

(3) Primarily reflects the fair value of oil commodity derivative contracts of $15.8 million at December 31, 2012 (Note 17). These contracts were settled in February 2013.

(4) Reflects the cash deposit we received in association with the expected sales of our two remaining pipelay vessels, the Express and the Caesar, and other related pipelay equipment (Note 2), which is refundable in very limited circumstances. The sales of these vessels are scheduled to close and fund in two stages in 2013 following the completion of each vessel’s existing backlog of work.

Note 5 — Equity Investments

As of December 31, 2012, we had two investments that we account for using the equity method of accounting: Deepwater Gateway and Independence Hub, both of which are included in our Production Facilities segment.

Deepwater Gateway, L.L.C. In June 2002, we, along with Enterprise Products Partners L.P. (”Enterprise”), formed Deepwater Gateway, each with a 50% interest, to design, construct, install, own and operate a tension leg platform production hub primarily for Anadarko Petroleum Corporation's Marco Polo field in the Deepwater Gulf of Mexico. Our investment in Deepwater Gateway totaled $91.4 million and $96.0 million as of December 31, 2012 and 2011, respectively (including capitalized interest of $1.3 million and $1.4 million at December 31, 2012 and 2011, respectively).

Independence Hub, LLC. In December 2004, we acquired a 20% interest in Independence Hub, an affiliate of Enterprise. Independence Hub owns the "Independence Hub" platform located in Mississippi Canyon Block 920 in a water depth of 8,000 feet. Our investment in Independence Hub was $76.2 million and $79.7 million as of December 31, 2012 and 2011, respectively (including capitalized interest of $4.6 million and $4.9 million at December 31, 2012 and 2011, respectively).

We made the following contributions to our equity investments during the years ended December 31, 2012, 2011 and 2010 (in thousands):

	Year Ended December 31,		
	2012	2011	2010

Clough Helix Pty Ltd. (see below)	$ —	$2,699	$8,253
Total	$ —	$2,699	$8,253

We received the following distributions from our equity investments during the years ended December 31, 2012, 2011 and 2010 (in thousands):

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	Year Ended December 31,		
	2012	2011	2010
Deepwater Gateway	$8,157	$7,600	$8,125
Independence Hub	8,073	18,580	21,615
Other	—	—	268
Total	$16,230	$26,180	$30,008

In February 2010, we announced the formation of a joint venture with Australian-based engineering and construction company, Clough Limited (“Clough”), to provide a range of subsea services to offshore operators in the Asia Pacific region. The joint venture, then named Clough Helix Pty Ltd, was to perform its services using the Normand Clough, a 118-meter long multi-service chartered vessel. The joint venture also utilized each member’s personnel and equipment to perform its subsea services as provided in the joint venture agreement. In 2011, our share of the income associated with the Australian joint venture’s operations was $2.1 million. Our share of its losses was $3.6 million in 2010, which primarily reflects the cost associated with the commencement of its operations.

In December 2011, the marine construction and offshore engineering operations of Clough were acquired by a third party, including Clough’s 50% ownership interest in the joint venture. At December 31, 2011, we conducted an impairment assessment of our investment in the joint venture based on uncertainties concerning the continued availability of the Normand Clough and the limited backlog of existing projects at the time. We concluded that the $10.6 million carrying amount of the investment in the joint venture was fully impaired and recorded a $10.6 million other than temporary impairment charge in the accompanying consolidated statements of operations.

In the first quarter of 2012, we recorded additional losses totaling $3.8 million, including a $3.0 million fee when we negotiated our exit from the joint venture. In April 2012, we paid this fee. In connection with our exit, we were entitled to 50% of the value of certain of the net assets on hand at the time of our departure. We received approximately $3.7 million of proceeds for our pro rata portion of such assets of the joint venture, which was recorded as income in “Equity in earnings of investments” during the second quarter of 2012. We are no longer a participant in this Australian joint venture.

The summarized aggregated financial information related to the subsidiaries we record using the equity investment is as follows (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Revenues	$53,159	$193,521	$141,705
Operating income	30,463	97,954	93,324
Net income	30,463	93,215	93,005

	December 31,		
	2012	2011	2010
Current assets	$16,682	$39,754	$25,352
Total assets	537,251	591,761	594,645
Current liabilities	706	11,012	6,434
Total liabilities	5,320	27,163	19,695

Note 6 — Kommandor LLC

In October 2006, we partnered with Kommandor RØMØ, a Danish corporation, to form Kommandor LLC, a Delaware limited liability company, the purpose of which was to convert a ferry vessel into a ship-shaped dynamically-positioned floating production unit vessel. Upon completion of the conversion in April 2009, the vessel, (the HP I) was leased to us under a bareboat charter. We subsequently installed topside oil and gas processing equipment, at 100% our cost, that allows the HP I to serve as a floating production

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system. The HP I will primarily service fields in the Deepwater of the Gulf of Mexico. The initial plan was to utilize the HP I at the Phoenix field, in which we held a 70% working interest prior to the sale of ERT. In June 2010, the HP I was certified for use as a floating production unit by the U.S. Coast Guard. Following that certification, the HP I was preparing to initiate service to the Phoenix field; however, it was then contracted by BP to participate in the Macondo well control and containment efforts. The HP I participated in those response and containment efforts until early October 2010 at which time BP released it from its contract and the HP I returned to the Phoenix field where production commenced in October 2010. The HP I is under contract with ERT to service the Phoenix field through at least December 31, 2016.

The total cost of the conversion of the vessel was $148.7 million. The total cost of us to install the topside oil and gas processing facilities was $196.3 million.

The operating agreement with Kommandor RØMØ provides that for a period of two months immediately following the fifth anniversary of the completion of the initial conversion (April 2014 – June 2014, the "Helix Option Period"), we may purchase Kommandor RØMØ's membership interest at a value specified in the agreement. In addition, for a period of two months starting from 30 days after the Helix Option Period, Kommandor RØMØ can require us to purchase its share of the company at a value specified in the operating agreement. We estimate that the cash outlay to Kommandor RØMØ for its interest in Kommandor LLC at the time the put or call is exercised will be approximately $19 million.

The consolidated results of Kommandor LLC are included in our Production Facilities segment. We own approximately 81% of Kommandor LLC at December 31, 2012.

Note 7 — Long-Term Debt

Long-term debt consisted of the following as of December 31, 2012 and 2011 (in thousands):

	2012	2011
Term Loans (mature July 2015)	$367,181	$279,750
Revolving Credit Facility (matures July 2015)	100,000	—
2025 Notes (mature December 2025)	3,487	300,000
2032 Notes (mature March 2032)	200,000	—
Senior Unsecured Notes (mature January 2016)	274,960	474,960
MARAD Debt (matures February 2027)	105,288	110,166
Unamoritized debt discount	(31,688)	(9,555)
Total debt	1,019,228	1,155,321
Less current maturities	(16,607)	(7,877)
Long-term debt	$1,002,621	$1,147,444

Senior Unsecured Notes

In December 2007, we issued $550 million of 9.5% Senior Unsecured Notes due 2016 ("Senior Unsecured Notes"). The Senior Unsecured Notes are fully and unconditionally guaranteed by substantially all of our existing restricted domestic subsidiaries, except for Cal Dive I-Title XI, Inc. In addition, any future restricted domestic subsidiaries that guarantee any of our indebtedness and/or our restricted subsidiaries' indebtedness are required to guarantee the Senior Unsecured Notes. Our foreign subsidiaries are not guarantors.

The Senior Unsecured Notes are junior in right of payment to all our existing and future secured indebtedness and obligations and rank equally in right of payment with all of our existing and future senior unsecured indebtedness. The Senior Unsecured Notes rank senior in right of payment to any of our future subordinated indebtedness.

The Senior Unsecured Notes mature on January 15, 2016. Interest on the Senior Unsecured Notes accrues at the fixed rate of 9.5% per annum and is payable semiannually in arrears on each January 15 and July 15, and commenced on July 15, 2008. Interest is computed on the basis of a 360-day year comprising twelve 30-day months.

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Included in the Indenture governing the Senior Unsecured Notes are terms, conditions and covenants that are customary for this type of indebtedness. The covenants include limitations on our and our subsidiaries' ability to incur additional indebtedness, pay dividends, repurchase our common stock, and sell or transfer assets. As of December 31, 2012, we were in compliance with these covenants.

Prior to stated maturity, we may redeem all or a portion of the Senior Unsecured Notes on no less than 30 days' and no more than 60 days' prior notice at the redemption prices (expressed as percentages of the principal amount) set forth below, plus accrued and unpaid interest, if any, thereon to the applicable redemption date.

Year	Redemption Price
2012	104.750%
2013	102.375%
2014 and thereafter	100.000%

In the event a change of control (as defined in the governing Indenture) of the Company occurs, each holder of the Senior Unsecured Notes will have the right to require us to purchase all or any part of such holder's Senior Unsecured Notes. In such event, we are required to offer to purchase all of the Senior Unsecured Notes at a purchase price in cash in an amount equal to 101% of the principal amount, plus accrued and unpaid interest, if any, to the date of purchase.

At December 31, 2010, we had $550.0 million of Senior Unsecured Notes outstanding. In 2011, we purchased a portion of our Senior Unsecured Notes that resulted in the early extinguishment of an aggregate $75.0 million of those notes. In these transactions we paid an aggregate amount of $77.4 million, including $75.0 million in principal and $2.4 million in premium for the repurchased Senior Unsecured Notes. We also paid the accrued interest on these Senior Unsecured Notes totaling $0.8 million and we recorded a $0.9 million charge to interest expense to accelerate a pro rata portion of the deferred financing costs associated with the issuance of the Senior Unsecured Notes in 2007.

At December 31, 2011, we had $475.0 million of Senior Unsecured Notes outstanding. In March 2012, we purchased a portion of these Senior Unsecured Notes which resulted in an early extinguishment of $200.0 million of our balance outstanding. In these transactions we paid an aggregate amount of $213.5 million, including $200.0 million in principal, a $9.5 million premium and $4.0 million of accrued interest. We also recorded a $2.0 million charge to accelerate a pro rata portion of the deferred financing costs associated with the original issuance of the Senior Unsecured Notes. The loss on the early extinguishment of these Senior Unsecured Notes totaled $11.5 million and is reflected as a component of "Loss on early extinguishment of long-term debt" in the accompanying consolidated statements of operations.

Credit Agreement

In July 2006, we entered into a credit agreement (the "Credit Agreement") under which we borrowed $835 million in a term loan (the "Term Loan B") and were able to borrow up to $300 million (the "Revolving Loans") under a revolving credit facility (the "Revolving Credit Facility"). The Credit Agreement has been amended seven times, with the most recent amendment occurring in September 2012. These amendments address certain issues with regard to covenants, maturity and the borrowing limits under the Term Loan B and the Revolving Loans.

In February 2013, we amended the credit agreement to waive certain year end oil and gas reporting requirements and covenant compliance as a result of the sale of ERT.

In September 2012, we amended the credit agreement to primarily:

- permit investments in (i) non-guarantor, non-pledged subsidiaries and (ii) joint ventures, provided that after giving effect to each such investment, a minimum consolidated liquidity requirement of $400 million is met on a pro forma basis;
- increase the debt basket for foreign subsidiaries (other than specified foreign subsidiaries that currently are excepted from this debt basket) from $200 million to $400 million provided that such indebtedness is non-recourse to us and our other subsidiaries (the “Foreign Subsidiary Debt Basket”); and

- exclude, to the extent it otherwise would be included in the calculation of financial covenants, EBITDA, interest charges and indebtedness related to assets secured by, or otherwise subject to, the indebtedness permitted by the Foreign Subsidiary Debt Basket.

In February 2012, we entered into a separate amendment to our Credit Agreement. Under the terms of this amendment, the participating lenders agreed to loan us $100.0 million pursuant to an additional term loan (the "Term Loan A"). The terms of the Term Loan A are the same as those governing the Revolving Credit Facility, with the Term Loan A requiring a $5 million annual payment of its principal balance. The Term Loan A was funded in late March 2012 and we used the borrowings under the Term Loan A to repurchase a portion of our Senior Unsecured Notes.

Our Term Loan debt currently bears interest at the one-, two-, three- or six-month LIBOR or on Base Rates at our current election plus an applicable margin between 2.25% and 3.5% depending on our consolidated leverage ratio. The average interest rates on our Term Loan debt for the years ended December 31, 2012 and 2011 were approximately 3.7% and 3.8%, respectively, including the effects of our interest rate swaps (Note 17). The Term Loans are currently scheduled to mature on July 1, 2015 but could be extended to July 1, 2016 if our Senior Unsecured Notes are fully repaid or refinanced by July 1, 2015.

Our Revolving Credit Facility provides for $600 million in borrowing capacity. The full amount of the Revolving Credit Facility may be used for issuances of letters of credit. These letters of credit primarily guarantee asset retirement obligations as well as various contract bidding, contractual performance, insurance activities and shipyard commitments. The Revolving Loans bear interest based on one-, two-, three- or six-month LIBOR rates or on Base Rates at our current election, plus an applicable margin. The margin ranges from 1.5% to 3.5%, depending on our consolidated leverage ratio. Fees associated with outstanding letters of credit range from 2.0% to 3.0%, depending on our consolidated leverage ratio. We also pay a fixed commitment fee of 0.5% on the unused portion of our Revolving Credit Facility. In March 2012, we borrowed $100.0 million under our Revolving Credit Facility to repurchase a portion of our Senior Unsecured Notes. Accordingly, at December 31, 2012, we had $100.0 million drawn on the Revolving Credit Facility and our availability under the Revolving Credit Facility totaled $487.6 million, net of $12.4 million of letters of credit issued. The average interest rate under the Revolving Credit Facility totaled 3.0% for the period in which we had borrowings outstanding during the year ended December 31, 2012. There were no borrowings outstanding at December 31, 2011.

We may elect to prepay amounts outstanding under the Term Loans without prepayment penalty, but may not reborrow any amounts prepaid. We may prepay amounts outstanding under the Revolving Loans without prepayment penalty, and may reborrow amounts prepaid prior to maturity. In addition, upon the occurrence of certain dispositions or the issuance or incurrence of certain types of indebtedness, we may be required to prepay a portion of the Term Loan debt and borrowings under the Revolving Credit Facility equal to the amount of proceeds received from such occurrences (in the event of a disposition of assets comprising collateral, 60% of the after-tax proceeds). Such prepayments will be applied first to the Term Loan B, and any excess will then be applied to the Term Loan A and the Revolving Credit Facility on a pro rata basis. In February 2013, we repaid $293.9 million of our Term Loans and $24.5 million under our Revolving Credit Facility with the after-tax proceeds from the sale of ERT. At February 19, 2013, the remaining balance on our Term Loan debt totaled $73.3 million and the balance outstanding on our Revolving Credit Facility totaled $78.1 million.

The Credit Agreement and the other ancillary loan documents (together, the "Loan Documents") include terms, conditions and covenants that we consider customary for this type of indebtedness. The covenants include restrictions on the Company's and our subsidiaries' ability to grant liens, incur indebtedness, make investments, merge or consolidate, sell or transfer assets and pay dividends. The Credit Agreement also places certain annual and aggregate limits on expenditures for acquisitions, investments in joint ventures and capital expenditures. The Credit Agreement requires us to meet certain minimum financial ratios for interest coverage, consolidated leverage, senior secured debt leverage and, until we achieve investment grade ratings from Standard & Poor's and Moody's, collateral coverage.

If we or any of our subsidiaries do not pay any amounts owed to the lenders under the Credit Agreement when due, breach any other covenant to the lenders or fail to pay other debt above a stated threshold, in each case, subject to applicable cure periods, the lenders have the right to stop making advances to us and to declare the outstanding loans immediately due. The Credit Agreement includes other

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events of default that are customary for this type of transaction. As of December 31, 2012, we were in compliance with all debt covenants and restrictions.

The loans and our other obligations to the lenders under the Credit Agreement are guaranteed by all of our U.S. subsidiaries except Cal Dive I-Title XI, Inc., and are secured by a lien on substantially all of our assets and properties and all the assets and properties of our U.S. subsidiaries except Cal Dive I-Title XI, Inc. In addition, we have pledged a portion of the shares of our significant foreign subsidiaries to the lenders as additional security. The Credit Agreement also contains provisions that limit our ability to incur certain types of additional indebtedness. These provisions effectively prohibit us from incurring any additional secured indebtedness or indebtedness guaranteed by us. The Credit Agreement does however permit us to incur certain unsecured indebtedness, and also provides for our subsidiaries to incur project financing indebtedness (such as our MARAD loans) secured by the underlying asset, provided that the indebtedness is not guaranteed by us.

Convertible Senior Notes Due 2025

In March 2005, we issued $300 million of our 3.25% Convertible Senior Notes due 2025 at 100% of the principal amount to certain qualified institutional buyers (“2025 Notes”). The effective interest rate for the 2025 Notes is 6.6% after considering the effect of the accretion of the related debt discount that represented the equity component of the 2025 Notes at their inception.

In association with the issuance of additional Convertible Senior Notes (see “Convertible Senior Notes Due 2032” below) in March 2012, we repurchased $142.2 million in aggregate principal of our 2025 Notes. In these repurchase transactions we paid an aggregate amount of $145.1 million, representing principal plus $1.8 million of premium and $1.1 million of accrued interest. The loss on the early extinguishment of these related 2025 Notes totaled $5.6 million and is reflected as a component of “Loss on early extinguishment of long-term debt” in the accompanying consolidated statements of operations. The loss on early extinguishment includes the acceleration of $3.5 million of related unamortized discount associated with the 2025 Notes, the $1.8 million premium paid in connection with the repurchase of a portion of the 2025 Notes and a $0.3 million charge to accelerate a pro rata portion of the deferred financing costs associated with the original issuance of these 2025 Notes.

As of the date of this filing, there are no outstanding 2025 Notes. The repayment of this debt occurred when holders of $154.3 million of the 2025 Notes exercised their option on December 15, 2012 to require us to repurchase their 2025 Notes and we repurchased the remaining $3.5 million of the 2025 Notes in February 2013.

Our weighted average share price for 2012, 2011 and 2010 was below the $32.14 per share conversion price. As a result, there are no shares included in our diluted earnings per share calculation associated with the assumed conversion of our 2025 Notes.

Convertible Senior Notes Due 2032

In March 2012, we completed the public offering and sale of $200.0 million in aggregate principal amount of 3.25% Convertible Senior Notes due 2032 (“2032 Notes”). The net proceeds from the issuance of the 2032 Notes were $195.0 million, after deducting the underwriter’s discounts and commissions and estimated offering expenses. We used the net proceeds to repurchase and retire $142.2 million of aggregate principal amount of our 2025 Notes (see above), in separate, privately negotiated transactions. The remaining net proceeds were used for other general corporate purposes, including the repayment of other indebtedness.

The registered 2032 Notes bear interest at a rate of 3.25% per annum, and are payable semi-annually in arrears on March 15 and September 15 of each year, beginning on September 15, 2012. The 2032 Notes will mature on March

15, 2032, unless earlier converted, redeemed or repurchased by us. The 2032 Notes are convertible in certain circumstances and during certain periods at an initial conversion rate of 39.9752 shares of common stock per $1,000 principal amount of the 2032 Notes (which represents an initial conversion price of approximately $25.02 per share of common stock), subject to adjustment in certain circumstances as set forth in the indenture governing the 2032 Notes. The initial conversion price represents a conversion premium of 35.0% over the closing price of our common stock on March 6, 2012 of $18.53 per share.

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Prior to March 20, 2018, the 2032 Notes will not be redeemable. On or after March 20, 2018, we may, at our option, redeem some or all of the 2032 Notes in cash, at any time, upon at least 30 days' notice at a price equal to 100% of the principal amount plus accrued and unpaid interest (including contingent interest, if any) up to but excluding the redemption date. Holders may require us to purchase in cash some or all of their 2032 Notes at a repurchase price equal to 100% of the principal amount of the 2032 Notes, plus accrued and unpaid interest (including contingent interest, if any) up to but excluding the applicable repurchase date, on March 15, 2018, March 15, 2022 and March 15, 2027, or, subject to specified exceptions, at any time prior to the 2032 Notes' maturity following a fundamental change (as defined in the governing indenture).

In connection with the issuance of our 2032 Notes, we recorded a discount of $35.4 million as required under existing accounting requirements. To arrive at this discount amount, we estimated the fair value of the liability component of the 2032 Notes as of the date of their issuance (March 12, 2012) using an income approach. To determine this estimated fair value, we used borrowing rates of similar market transactions involving comparable liabilities at the time of issuance and an expected life of 6.0 years. In selecting the expected life, we selected the earliest date that the holder could require us to repurchase all or a portion of the 2032 Notes (March 15, 2018). The effective interest rate for the 2032 Notes is 6.9% after considering the effect of the accretion of the related debt discount that represented the equity component of the 2032 Notes at their inception.

Our weighted average share price for 2012 was below the $25.02 per share conversion price. As a result, there are no shares included in our diluted earnings per share calculation associated with the assumed conversion of our 2032 Notes.

MARAD Debt

This U.S. government guaranteed financing ("MARAD Debt") is pursuant to Title XI of the Merchant Marine Act of 1936 administered by the Maritime Administration, and was used to finance the construction of the Q4000. The MARAD Debt is payable in equal semi-annual installments beginning in August 2002 and matures 25 years from such date. The MARAD Debt is collateralized by the Q4000, with us guaranteeing 50% of the debt, and initially bore interest at a floating rate which approximated AAA Commercial Paper yields plus 20 basis points. As provided for in the MARAD Debt agreements, in September 2005, we fixed the interest rate on the debt through the issuance of a 4.93% fixed-rate note with the same maturity date (February 2027). In accordance with the MARAD Debt agreements, we are required to comply with certain covenants and restrictions, including the maintenance of minimum net worth, working capital and debt-to-equity requirements. At December 31, 2012, we were in compliance with these debt covenants.

Other

In accordance with our Credit Agreement, Senior Unsecured Notes, 2025 Notes, 2032 Notes and MARAD Debt agreements, we are required to comply with certain covenants, including the maintenance of minimum net worth, working capital and debt-to-equity requirements, and restrictions that limit our ability to incur certain types of additional indebtedness. As of December 31, 2012, we were in compliance with these covenants and restrictions.

We paid financing costs associated with our debt totaling $7.6 million in 2012 and $9.3 million in 2011. Unamortized deferred financing costs are included in "Other assets, net" in the accompanying consolidated balance sheets and are being amortized over the life of the respective debt agreements. The following table reflects the components of our deferred financing costs for the years ended December 31, 2012 and 2011 (in thousands):

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	2012			2011		
	Gross Carrying Amount	Accumulated Amortization	Net	Gross Carrying Amount	Accumulated Amortization	Net
Term Loans (mature July 2015)	$ 15,318	$ (11,595)	$ 3,723	$ 13,680	$ (10,257)	$ 3,423
Revolving Credit Facility (matures July 2015)	20,021	(12,466)	7,555	19,236	(9,640)	9,596
2025 Notes (mature December 2025)	8,189	(8,189)	—	8,189	(7,340)	849
2032 Notes (mature March 2032)	4,251	(534)	3,717	78	—	78
Senior Unsecured Notes (mature January 2016)	10,643	(8,252)	2,391	10,643	(5,546)	5,097
MARAD Debt (matures February 2027)	12,200	(5,248)	6,952	12,200	(4,760)	7,440
Total deferred financing costs	$ 70,622	$ (46,284)	$ 24,338	$ 64,026	$ (37,543)	$ 26,483

Scheduled maturities of long-term debt outstanding as of December 31, 2012 are as follows (in thousands):

	Term Loan (1)	Revolving Credit Facility (1)	Senior Unsecured Notes	2025 Notes (2)	MARAD Debt	2032 Notes (3)	Total
Less than one year	$ 8,000	$ —	$ —	$ 3,487	$ 5,120	$ —	$ 16,607
One to two years	8,000	—	—	—	5,376	—	13,376
Two to three years	351,181	100,000	—	—	5,644	—	456,825
Three to four years	—	—	274,960	—	5,926	—	280,886
Four to five years	—	—	—	—	6,222	—	6,222
Over five years	—	—	—	—	77,000	200,000	277,000
Total debt	367,181	100,000	274,960	3,487	105,288	200,000	1,050,916
Current maturities	(8,000)	—	—	(3,487)	(5,120)	—	(16,607)
Long-term debt, less current maturities	$ 359,181	$ 100,000	$ 274,960	$ —	$ 100,168	$ 200,000	$ 1,034,309
Unamortized debt discount (4)	—	—	—	—	—	(31,688)	(31,688)
Long-term debt	$ 359,181	$ 100,000	$ 274,960	$ —	$ 100,168	$ 168,312	$ 1,002,621

(1) Term Loan amounts reflect both our Term Loan A and Term Loan B. In February 2013, we repaid $293.9 million of our Term Loans and $24.5 million under our Revolving Credit Facility with the after-tax proceeds from the sale of ERT.

(2) We repurchased the remainder of the 2025 Notes in February 2013 (see "2025 Notes" above).

(3) Beginning in March 2018, the holders of these Convertible Senior Notes may require us to repurchase these notes or we may at our own option elect to repurchase notes. These notes will mature in March 2032.

(4) The notes will increase to their principal amount through accretion of non-cash interest charges through March 2018 for the Convertible Senior Notes due 2032.

The following table details our interest expense and capitalized interest for the years ended December 31, 2012, 2011 and 2010 (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Interest expense	$53,601	$72,824	$78,609
Interest income	(548)	(1,366)	(546)
Capitalized interest	(4,893)	(1,277)	(12,474)
Interest expense, net	$48,160	$70,181	$65,589

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Note 8 — Income Taxes

We and our subsidiaries, including acquired companies from their respective dates of acquisition, file a consolidated U.S. federal income tax return. We believe our recorded assets and liabilities are reasonable; however, tax laws and regulations are subject to interpretation and tax litigation is inherently uncertain, and therefore our assessments can involve a series of complex judgments about future events and rely heavily on estimates and assumptions.

Components of income tax provision (benefit) on continuing operations reflected in the consolidated statements of operations consisted of the following (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Current	$6,572	$(78,150)	$(22,930)
Deferred	(65,730)	41,344	42,096
	$(59,158)	$(36,806)	$19,166
Domestic	$(78,211)	$(51,590)	$1,596
Foreign	19,053	14,784	17,570
	$(59,158)	$(36,806)	$19,166

Income taxes have been provided based on the U.S. statutory rate of 35% and at the local statutory rate for each foreign jurisdiction adjusted for items which are allowed as deductions for federal and foreign income tax reporting purposes, but not for book purposes. The primary differences between the statutory rate and our effective rate from continuing operations are as follows:

	Year Ended December 31,		
	2012	2011	2010
Statutory rate	35.0%	35.0%	35.0%
Foreign provision	11.2	(291.0)	418.2
Effect of Australian reorganization	—	(2,984.3)	—
Nondeductible goodwill impairment (Note 2)	—	—	301.0
Valuation allowance on certain deferred tax assets	—	—	427.8
Other	0.8	(265.0)	(34.3)
Effective rate	47.0%	(3,505.3)%	1,147.7%

In 2011, we reorganized our Australian operating companies. The reorganization resulted in a recorded net tax benefit of $31.3 million associated with the impairment of our U.S. investment in the Australian subsidiaries.

Deferred income taxes result from the effect of transactions that are recognized in different periods for financial and tax reporting purposes. The nature of these differences and the income tax effect of each as of December 31, 2012 and 2011 are as follows (in thousands):

	2012	2011
Deferred tax liabilities:		
Depreciation and depletion	$336,471	$396,355
Original Issue Discount on 2025 and 2032 Notes	13,098	37,067

Equity investments in production facilities	81,082	76,911
Prepaid and other	10,548	14,779
Total deferred tax liabilities	$441,199	$525,112

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	2012	2011
Deferred tax assets:		
Net operating loss carryforward	$(36,981)	$(34,987)
Asset retirement obligations	(70,085)	(88,279)
Reserves, accrued liabilities and other	(35,229)	(39,995)
Total deferred tax assets	(142,295)	(163,261)
Valuation allowance	16,391	14,310
Net deferred tax liabilities	$315,295	$376,161
Deferred income tax is presented as:		
Current deferred tax assets	(43,942)	(41,449)
Noncurrent deferred tax liabilities	359,237	417,610
Net deferred tax liabilities	$315,295	$376,161

At December 31, 2012, our U.S. net operating loss carryforward totaled $17.6 million and our foreign tax credit carryforward totaled $6.7 million. The net operating loss carryforward will expire in 2030, while the foreign tax credit carryforward will expire in 2020. At this time, we anticipate utilizing these tax attributes before the statute of limitations expires. At December 31, 2012, we had a $16.4 million valuation allowance related to certain non-U.S. deferred tax assets, primarily net operating losses generated in Australia, as management believed it is more likely than not that we will not be able to utilize the tax benefit. Additional valuation allowances may be made in the future if in management's opinion it is more likely than not that the tax benefit will not be utilized. Any limitations on our ability to utilize our tax benefit carryforward could result in an increase in our federal income tax liability in future taxable periods.

We consider the undistributed earnings of our principal non-U.S. subsidiaries to be permanently reinvested. At December 31, 2012 and 2011, our principal non-U.S. subsidiaries had accumulated earnings and profits of approximately $167.9 million and $113.4 million, respectively. We have not provided deferred U.S. income tax on the accumulated earnings and profits.

We had $4.5 million related to uncertain tax positions as of December 31, 2012. In 2012, we reversed a $2.8 million long-term liability related to an uncertain tax position that was projected to be included on our 2011 tax return. The tax position was not taken when the 2011 tax return was filed. We account for tax-related interest in interest expense and tax penalties in operating expenses. We charged $0.2 million, $0.2 million and $0.7 million to income tax expense for interest and penalties accrued in 2012, 2011 and 2010, respectively, which brought our total liabilities for interest and penalties to $1.1 million and $0.9 million on our accompanying consolidated balance sheets at December 31, 2012 and 2011, respectively. As of December 31, 2012, 2011, and 2010, there were $3.4 million, $6.2 million and $3.4 million of unrecognized tax benefits that if recognized would affect the annual effective rate. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows (in thousands):

	2012	2011	2010
Balance at January 1,	$7,085	$4,085	$3,417
Additions based on tax positions related to current year	—	2,785	—
Additions for tax positions of prior years	206	215	668
Reductions for tax positions of prior years	(2,785)	—	—
Balance at December 31,	$4,506	$7,085	$4,085

We file tax returns in the U.S. and in various state, local and non-U.S. jurisdictions. We anticipate that any potential adjustments to our state, local and non-U.S. jurisdiction tax returns by tax authorities would not have a material impact on our financial position. The tax periods ending December 31, 2010, 2009, 2008, 2007 and 2006 are under examination by the U.S. Internal Revenue Service ("IRS"). The tax periods ended December 31, 2012 and 2011 remain open to future review and examination by the IRS. In non-U.S. jurisdictions, the open tax periods include 2012, 2011, 2010, 2009 and 2008.

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Note 9 — Employee Benefit Plans

Defined Contribution Plan

We sponsor a defined contribution 401(k) retirement plan covering substantially all of our employees. Our contributions are in the form of cash and are determined annually as a 50% match of each employee's contribution up to 5% of the employee's salary. Our costs related to the 401(k) plan totaled $1.6 million, $1.4 million and $1.6 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Stock-Based Compensation Plans

We have two stock-based compensation plans: the 1995 Long-Term Incentive Plan, as amended (the "1995 Incentive Plan") and the 2005 Long-Term Incentive Plan, as amended (the "2005 Incentive Plan").

Upon adoption of the 1995 Incentive Plan in May 1995, a maximum of 10% of the total shares of common stock issued and outstanding were eligible to be granted to executive officers, selected management employees and non-employee members of our Board of Directors. Following the approval by shareholders of the 2005 Incentive Plan in May 2005, no further grants have been or will be made under the 1995 Incentive Plan.

In May 2012, the shareholders approved an amendment to and restatement of the 2005 Incentive Plan to: (i) authorize 4.3 million additional shares for issuance pursuant to our equity incentive compensation strategy, (ii) authorize incentive stock options, stock appreciation rights, cash awards and performance awards to be made pursuant to the amended and restated 2005 Incentive Plan, and (iii) include performance criteria for awards that may be made contingent upon the achievement of one or more performance measures, as well as limits on individual awards, in accordance with the requirements for performance-based compensation under Section 162(m) of the Internal Revenue Code. As of December 31, 2012, there were 6.6 million shares available for issuance under the amended and restated 2005 Incentive Plan, which includes a maximum of 2.0 million shares that may be granted as incentive stock options.

The 1995 and 2005 Incentive Plans are administered by the Compensation Committee of Helix's Board of Directors. The Compensation Committee also determines the type of award to be made to each participant and, as set forth in the related award agreement, the terms, conditions and limitations applicable to each award. The Compensation Committee may grant stock options, restricted stock, restricted stock units, and cash awards. Awards granted to employees under the incentive plans have typically vested 20% per year over a five-year period. Commencing in 2012, awards granted under the 2005 Incentive Plan have a vesting period of three years or 33% per year. There have been no stock options granted since 2004. Stock options granted have a maximum exercise life of 10 years.

Compensation cost for restricted shares is the product of grant date fair value of each share and the number of shares granted and is recognized over the respective vesting periods on a straight-line basis. Forfeitures on restricted stock totaled approximately 12% based on our most recent five-year average of historical forfeiture rates. Tax deduction benefits for an award in excess of recognized compensation cost is reported as a financing cash flow rather than as an operating cash flow. Stock based compensation that is based solely on service conditions is recognized on a straight line basis over the vesting period of the related shares.

Stock Options

The following table summarizes information about our stock options during the years ended December 31, 2012, 2011 and 2010:

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	2012		2011		2010	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Options outstanding at beginning of year	192,800	$10.52	432,918	$10.78	501,318	$10.74
Exercised	(140,000)	9.24	(181,670)	10.92	(68,400)	10.52
Terminated	—	—	(58,448)	11.20	—	—
Options outstanding at end of year	52,800	$13.91	192,800	$10.52	432,918	$10.78
Options exercisable at end of year	52,800	$13.91	192,800	$10.52	432,918	$10.78

There was no compensation recognized associated with stock options in 2012, 2011 or 2010 as all stock options outstanding are vested. The aggregate intrinsic value of the stock options exercised in 2012, 2011 and 2010 was approximately $1.3 million, $1.1 million and $0.1 million, respectively. The aggregate intrinsic value of options exercisable at December 31, 2012, 2011 and 2010 was approximately $0.4 million, $1.0 million and $0.6 million, respectively. The weighted average remaining contractual life of stock option awards at December 31, 2012 was 1.4 years.

Share-based Awards

We grant share-based awards (restricted stock, restricted stock units ("RSUs") and/or performance share units ("PSUs")) to members of our Board of Directors, executive officers and selected management employees. The following table summarizes information about our share-based awards during the years ended December 31, 2012, 2011 and 2010:

	2012		2011		2010	
	Shares	Grant Date Fair Value (1)	Shares	Grant Date Fair Value (1)	Shares	Grant Date Fair Value (1)
Awards outstanding at beginning of year	1,263,218	$14.80	1,463,298	$16.93	1,443,265	$21.55
Granted	482,340	18.33	571,163	12.77	599,996	12.01
Vested (2)	(400,180)	18.07	(504,813)	19.87	(444,905)	25.10
Forfeited	(21,066)	15.00	(266,430)	12.55	(135,058)	17.48
Awards outstanding at end of year	1,324,312	$15.09	1,263,218	$14.80	1,463,298	$16.93

(1) Represents the weighted average grant date fair value, which is based on the quoted market price of the common stock on the business day prior to the date of grant.

(2) Total fair value of share-based awards that vested during the years ended December 31, 2012, 2011 and 2010 was $6.7 million, $6.7 million and $5.6 million, respectively.

For the years ended December 31, 2012, 2011 and 2010, $7.7 million, $8.4 million, $9.0 million, respectively, was recognized as stock-based compensation expense related to share-based awards. Future compensation cost associated with unvested share-based awards at December 31, 2012, 2011, and 2010 totaled approximately $13.2 million, $12.0 million and $16.8 million, respectively. The weighted average vesting period related to unvested share-based awards at December 31, 2012 was approximately 2.2 years.

The following grants of share-based awards were made in 2012 under the amended and restated 2005 Incentive Plan:

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Date of Grant	Shares	Grant Date Fair Value Per Share	Vesting Period
January 3, 2012 (1)	272,153	$ 15.80	33% per year over three years
January 3, 2012 (2)	132,910	23.68	100% on January 1, 2015
January 3, 2012 (3)	1,958	15.80	100% on January 1, 2014
April 1, 2012 (3)	1,879	17.80	100% on January 1, 2014
July 2, 2012 (3)	1,885	16.41	100% on January 1, 2014
August 23, 2012 (3)	3,539	18.84	20% per year over five years
October 1, 2012 (3)	1,830	18.27	100% on January 1, 2014
December 6, 2012 (3)	66,186	18.13	33% per year over three years

(1) Reflects the grant of 132,910 restricted shares to our executive officers and 139,243 RSUs to selected management employees that are convertible into 139,243 shares of our common stock upon vesting. These RSUs may be settled in cash or common stock at the Company's option.

(2) Reflects the grant of PSUs to our executive officers. The estimated fair value of the PSUs on grant date was determined using a Monte Carlo simulation model. The PSUs provide for an award based on the performance of our common stock over a three-year period with the maximum award being 200% of the original awarded PSUs and the minimum amount being zero. The vested PSUs will be settled in an equivalent number of shares of our common stock unless the Compensation Committee of our Board of Directors elects to pay in cash.

(3) Reflects grants to our directors.

In January 2013, we granted our executive officers 89,329 restricted shares under the 2005 Long-Term Incentive Plan. The market value of the restricted shares was $20.64 per share or $1.8 million and the shares vest 33% per year for a three-year period. Separately, we issued our executive officers 89,329 PSUs. The PSUs provide for an award based on the performance of our common stock over a three-year period with the maximum amount of the award being 200% of the original awarded PSUs and the minimum amount being zero. The PSUs vest 100% on the three-year anniversary date of the grant. The vested PSUs will be settled in an equivalent number of shares of our common stock unless the Compensation Committee of our Board of Directors determines to pay in cash.

Stock Compensation Modifications

Under our 1995 Incentive Plan and our 2005 Long-Term Incentive Plan, upon a stock recipient's termination of employment, which is defined as employment with us and any of our majority-owned subsidiaries, any unvested restricted stock and stock options are forfeited immediately, and all unexercised vested options are forfeited as specified under the applicable plan or agreement.

Employee Stock Purchase Plan

In May 2012, the shareholders approved the Helix Energy Solutions Group, Inc. Employee Stock Purchase Plan (the "ESPP"). The ESPP has 1.5 million shares authorized for issuance. Eligible employees who participate in the ESPP may purchase shares of our common stock through payroll deductions on an after-tax basis over a four-month period beginning on January 1, May 1, and September 1 of each year during the term of the ESPP, subject to certain restrictions and limitations established by the Compensation Committee of our Board of Directors (which administers the ESPP) and Section 423 of the Internal Revenue Code. The per share price of common stock purchased under the ESPP is equal to 85% of the lesser of (i) its fair market value on the first trading day of the purchase period or (ii) its fair market value on the last trading day of the purchase period. The first purchase period under the ESPP began on September 1, 2012. The total value of the ESPP awards is calculated using the component approach where each award is computed as the sum of 15% of a share of non-vested stock, a call option on 85% of a share of non-vested stock, and a put option on 15% of a share of non-vested stock. Share-based compensation expense with respect to the ESPP was $0.3 million for the year ended December 31, 2012.

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Long-Term Incentive Cash Plan

In January 2009, we adopted the 2009 Long-Term Incentive Cash Plan (the "2009 LTI Plan") to provide long-term cash-based compensation to eligible employees. Our executive officers and certain other members of senior management as designated from time to time by the Compensation Committee of our Board of Directors are granted cash awards. Under the terms of the 2009 LTI Plan, cash awards historically have been both fixed sum amounts payable (for non-executive management only) as well as cash awards indexed to our common stock with the payment amount at each vesting date fluctuating based on the performance of our common stock (for both executive and non-executive management). These are measured based on the performance of our stock price over the applicable award period compared to a base price determined by the Compensation Committee of our Board of Directors at the time of the award. The measurement period to determine the annual payment for the share-based cash awards is generally the last 20 trading days of the year (the last 30 trading days for the 2009 awards). Payment amounts are based on the calculated ratio of the average stock price during the applicable measurement period over the original base price as determined by the Compensation Committee of our Board of Directors. The maximum amount payable under these share-based cash awards is twice the original targeted award and if the average price during the measurement period is less than 75% (50% for 2010 grants) of the base price, no payout will be made at the applicable anniversary date. Payments under the 2009 LTI Plan are made each year on the anniversary date of the award. Awards granted prior to 2012 have a vesting period of five years and awards granted in 2012 and 2013 have a vesting period of three years. This share-based component is considered a liability plan and as such is re-measured to fair value each reporting period with corresponding changes being recorded as a charge to earnings as deemed appropriate.

The awards made under the 2009 LTI Plan totaled $4.2 million in 2012, $5.2 million in 2011, and $10.2 million in 2010. All such awards were made to our executive officers except for $4.3 million of the total award in 2010. Total compensation expense associated with the 2009 LTI Plan was $8.7 million ($7.3 million related to our executive officers), $7.9 million ($6.5 million related to our executive officers) and $8.6 million ($6.9 million related to our executive officers), respectively, for the years ended December 31, 2012, 2011 and 2010. The liability balance under the 2009 LTI Plan was $13.0 million at December 31, 2012 and $9.9 million at December 31, 2011, including $11.7 million at December 31, 2012 and $8.5 million at December 31, 2011 associated with the variable portion of the 2009 LTI plan. During 2012, 2011 and 2010, we paid $5.5 million, $5.9 million and $4.4 million of the liability associated with the 2009 LTI plan. We paid $7.1 million of this liability on January 4, 2013. In January 2013, $5.9 million was awarded under the 2009 LTI Plan to executive officers and selected management employees. No cash awards were given to non-executive employees in 2012 or 2011.

Note 10 — Shareholders' Equity

Our amended and restated Articles of Incorporation provide for authorized Common Stock of 240,000,000 shares with no stated par value per share and 5,000,000 shares of preferred stock, $0.01 par value per share issuable in one or more series.

The components of accumulated other comprehensive loss as of December 31, 2012 and 2011 are as follows (in thousands):

	2012	2011
Cumulative foreign currency translation adjustment	$(15,667)	$(22,958)
Unrealized gain on hedges, net (1)	—	12,941
Accumulated other comprehensive loss	$(15,667)	$(10,017)

(1) Amount at December 31, 2011 is net of deferred income tax liabilities totaling $7.0 million. In December 2012, all of our oil and natural gas commodity derivative contracts no longer qualified for hedge accounting following the announcement of the sale of ERT (Note 2).

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Note 11 — Stock Buyback Program

In June 2009, we announced that we intended to purchase up to 1.5 million shares of our common stock plus an amount equal to additional shares of our common stock granted under our stock-based compensation plans (Note 9) as permitted under our Credit Agreement (Note 7). Our Board of Directors had previously granted us the authority to repurchase shares of our common stock in an amount equal to any equity based grants made pursuant to our stock-based compensation plans. We may continue to make repurchases pursuant to this authority from time to time as additional equity based grants are made under our stock based compensation plans depending on prevailing market conditions and other factors. All repurchases may be commenced or suspended at any time at the discretion of management. In June 2012, we purchased the remaining 405,063 shares then available under this plan for $6.4 million or an average of $15.82 per share. As of December 31, 2012, we had repurchased a total of 2,878,793 shares of our common stock for $36.9 million or an average of $12.83 per share. We retire all repurchased shares.

Note 12 — Related Party Transactions

In April 2000, we acquired a 20% working interest in Gunnison, a deepwater Gulf of Mexico prospect, from a third party. Financing for the exploratory costs of approximately $20 million was provided by an investment partnership ("OKCD"), the investors of which include current and former Helix management, in exchange for a revenue interest that is an overriding royalty interest of 25% of Helix's working interest. Production began in December 2003. Our payments to OKCD totaled $6.9 million, $8.3 million and $11.2 million in the years ended December 31, 2012, 2011 and 2010, respectively. Our Chief Executive Officer, Owen Kratz, through Class A limited partnership interests in OKCD, personally owns approximately 81% of the partnership. In 2000, OKCD also awarded Class B income participations to key Helix employees who are required to maintain their employment status with Helix in order to retain such income participations.

A former member of our Board of Directors is part of the senior management team of Weatherford International, Ltd (Weatherford). This individual resigned from our Board of Directors in May 2011. We paid Weatherford, an oil and gas industry company, $3.6 million for services provided to us in 2011 and $6.9 million for services provided in 2010.

Note 13 — Commitments and Contingencies and Other Matters

Commitments

Commitments Related to Expansion of Well Intervention Fleet

In March 2012, we executed a contract with a shipyard in Singapore for the construction of a newbuild semisubmersible well intervention vessel, the Q5000. This $386.5 million shipyard contract represents the majority of the expected costs associated with the construction of the Q5000. Under the terms of this contract, payments are made in a fixed percentage of the contract price, together with any variations, on contractually scheduled dates. At December 31, 2012, our total investment in the Q5000 was $139.6 million, including $115.9 million of scheduled payments made to the shipyard in 2012.

In July 2012, we contracted to charter the Skandi Constructor for use in our North Sea and Canadian well intervention operations. The initial term of the charter will be three years once the vessel is delivered to us in the first half of 2013.

In August 2012, we acquired the Discoverer 534 drillship from a subsidiary of Transocean Ltd. for $85 million. The vessel, renamed the Helix 534, is currently undergoing upgrades and modifications in Singapore to render it suitable for use as a well intervention vessel. At December 31, 2012, our investment in the acquisition and subsequent upgrades and modifications of the Helix 534 totaled $113.5 million.

Lease Commitments

We lease several facilities, ROVs and vessels under non-cancelable operating leases. Future minimum rentals under these leases at December 31, 2012 are as follows:

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	ROVs and Vessels	Facilities and Other	Total
2013	$ 84,409	$ 1,948	$ 86,357
2014	87,942	3,077	91,019
2015	86,155	3,620	89,775
2016	60,019	3,289	63,308
2017	38,188	3,153	41,341
Thereafter	4,905	22,778	27,683
Total lease commitments	$ 361,618	$ 37,865	$ 399,483

Total rental expense under these operating leases was approximately $85.0 million, $62.2 million and $66.2 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Contingencies and Claims

Under terms of the ERT equity purchase agreement, we have required the buyer to provide bonding in a sufficient amount as determined by the BOEM to replace and allow for a full discharge of our existing guaranty to the BOEM for ERT's lease obligations. The BOEM is in the process of reevaluating its decommissioning assessments for lease properties in the Gulf of Mexico and as such it is currently uncertain as to the amount of bonding that will be required, and thus also the amount of collateral that the buyer will be required to post to its surety/ies to secure such bonding. To the extent that the purchaser is required to post bonding collateral in an amount greater than $100 million to obtain bonds in the aggregate amount required by the BOEM in order for the BOEM to release our guaranty of ERT's lease obligations, we have agreed to provide incremental collateral above that amount, if and to the extent required, to the surety/ies providing bonding for the deepwater properties (the Bushwood and Phoenix fields) in the form of letter(s) of credit, up to the next $50 million of required collateral, for a period not to exceed one year from issuance of the letter(s) of credit, after which the purchaser would then be required to provide all collateral associated with the bonding requirements with respect to our former oil and gas properties. As the BOEM conducts its review of the Gulf of Mexico decommissioning assessments, we intend to work closely with the purchaser to provide specific information regarding our former lease properties. We anticipate that the BOEM will determine its assessments of decommissioning costs for our former deepwater fields in the near term and that the bonding amounts, and therefore the bonding collateral requirements, to obtain a release of our guaranty with respect to ERT's lease obligations will be known. At the time of this filing it is uncertain whether the amount of collateral will exceed the $100 million threshold so as to require any incremental bonding collateral on our part.

We were subcontracted to perform development work for a large gas field offshore India. Work commenced in the fourth quarter of 2007 and we completed our scope of work in the third quarter of 2009. To date we have collected approximately $303 million related to this project with an amount of trade receivables yet to be collected. We have requested arbitration in India pursuant to the terms of the subcontract to pursue our claims and the prime contractor has also requested arbitration and has asserted certain counterclaims against us. If we are not successful in resolving these matters through ongoing discussions with the prime contractor, then arbitration in India remains a potential remedy. Based on a number of factors associated with the ongoing negotiations with the prime contractor, in 2010, we established a $4 million allowance against our trade receivable balance that reduces its balance to an amount we believe is ultimately realizable. However, at the time of this filing no final commercial resolution of this matter has been reached.

We have received value added tax (VAT) assessments from the State of Andhra Pradesh, India (the "State") in the amount of approximately $28 million for the tax years 2010, 2009, 2008 and 2007 related to an Indian subsea construction and diving contract that we entered into in December 2006. The State claims we owe unpaid taxes related to products consumed by us during the period of the contract. We are of the opinion that the State has arbitrarily assessed this VAT tax and has no foundation for the assessment and believe that we have complied with all rules and regulations as related to VAT in the State. We also believe that our position is supported by law and intend to vigorously defend our position. However, the ultimate outcome of this assessment and our potential liability from it, if any, cannot be determined at this time. If the current assessment is upheld, it may have a material negative effect on our consolidated results of operations while also impacting our financial position.

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Litigation

On July 8, 2011, a shareholder derivative lawsuit styled City of Sterling Heights Police & Fire Retirement System v. Owen Kratz, et al. was filed in the United States District Court for the Southern District of Texas, Houston Division. In the suit, the plaintiff makes claims against our Board of Directors, certain of our former directors, our top current and former executives and the independent compensation consultant to the Compensation Committee of our Board of Directors, for breaches of the fiduciary duty of loyalty, unjust enrichment and aiding and abetting the alleged breaches of fiduciary duty relating to the long-term equity awards granted in 2010 to certain of the Company's executive officers. The Company filed a motion to dismiss the claim asserting that the plaintiff has not (i) pled specific facts excusing its failure to make pre-suit demand on the Company's Board of Directors as required by Minnesota law; (ii) filed proper verification; or (iii) stated a claim. A ruling regarding the motion is pending.

On May 12, 2012, a shareholder derivative lawsuit styled Mark Lucas v. Owen Kratz, et al. was filed in the 270th Judicial District in the District Court of Harris County, Texas. In the suit, the plaintiff makes claims against our Board of Directors, certain of our former directors, certain of our current and former executive officers and the independent compensation consultant to the Compensation Committee of our Board of Directors, for breaches of the fiduciary duties of candor, good faith and loyalty, unjust enrichment and aiding and abetting the alleged breaches of fiduciary duty relating to the long-term equity awards granted in 2010 to certain of our executive officers. This case is essentially a "copycat" complaint asserting similar causes of action arising out of the same facts as set forth in the federal action described above. We have filed a motion to stay, motion to dismiss, special exceptions, plea to the jurisdiction and an original answer asserting that: (i) the suit should be stayed in favor of a first-filed federal derivative case; (ii) the plaintiff has not pled specific facts showing wrongful refusal of demand; (iii) the plaintiff has not demonstrated he continually owned shares during the complained of action; and (iv) the plaintiff has not stated a claim. The plaintiff is generally demanding disgorgement of the excessive compensation, restraint on the disposition/exercise of the alleged improperly awarded equity, implementation of additional internal controls, and attorney's fees and costs of litigation.

We are involved in various legal proceedings, primarily involving claims for personal injury under the General Maritime Laws of the United States and the Jones Act based on alleged negligence. In addition, from time to time we incur other claims, such as contract disputes, in the normal course of business.

Insurance

We carry Hull and Increased Value insurance which provides coverage for physical damage up to an agreed amount for each vessel. The deductibles are based on the value of the vessel with a maximum deductible of $1.0 million on the Q4000, HP I and Well Enhancer, $500,000 on the Seawell, Express and Helix 534, and $750,000 on the Caesar. In addition to the primary deductibles, the vessels are subject to an annual aggregate deductible of $5 million. We also carry Protection and Indemnity ("P&I") insurance which covers liabilities arising from the operation of the vessels and General Liability insurance which covers liabilities arising from construction operations. The deductible on both the P&I and General Liability is $100,000 per occurrence. Onshore employees are covered by Workers' Compensation. Offshore employees and marine crews are covered by a Maritime Employers Liability ("MEL") insurance policy which covers Jones Act exposures and includes a deductible of $100,000 per occurrence plus a $1.0 million annual aggregate deductible. In addition to the liability policies described above, we currently carry various layers of Umbrella Liability for total limits of $500 million excess of primary limits. Our self-insured retention on our medical and health benefits program for employees is $250,000 per participant.

We incur workers' compensation, MEL, and other insurance claims in the normal course of business, which management believes are covered by insurance. The Company analyzes each claim for potential exposure and estimates the ultimate liability of each claim. At December 31, 2012, we did not have any claims exceeding our deductible limits. We have not incurred any significant losses as a result of claims denied by our insurance carriers. Our services are provided in hazardous environments where accidents involving catastrophic damage or loss of life could occur, and litigation arising from such an event may result in our being named a defendant in lawsuits asserting large claims. Although there can be no assurance the amount of insurance we carry is sufficient to protect us fully in all events, or that such insurance will continue to be available at current levels of cost or coverage, we believe that our insurance protection is adequate for our business operations. A successful liability claim for which we are underinsured or uninsured could have a material adverse effect on our business.

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Loss Contracts

Whenever we have a contract that qualifies as a loss contract, we estimate the future shortfall between our anticipated future revenues and future costs. In 2010, we had two contracts that resulted in significant losses. The first of these contracts represented the initial project performed by the Caesar. The project, which included a primary work scope of laying 36-miles of pipe in the Gulf of Mexico, was completed in the third quarter of 2010 at a total loss of $12.0 million. The loss was primarily the result of certain start-up performance issues with the vessel as well as non-reimbursable costs associated with weather delays. The second contract was entered into by our WOSEA subsidiary to plug, abandon and salvage subsea wells in an oil and gas field located offshore China. The project commenced in the second half of 2010 and was initially expected to be completed by the end of October 2010. However, the subsea wells were structurally difficult to plug. WOSEA also experienced some start-up issues with its recently repaired subsea intervention device, which was significantly damaged in March 2009. In the fourth quarter of 2010, WOSEA experienced significant weather delays corresponding with the peak of typhoon season in the China Sea, which added additional non reimbursable time and related costs to the project. As a result of the continued weather delays, it was mutually agreed that WOSEA would discontinue the project and in connection with that decision, the parties also agreed to a reduced scope of work for this project. Our operating results for the year ending December 31, 2010 included an aggregate $30 million pre-tax loss, which reflects the costs to complete the project over the contractual revenues as modified. In the first quarter of 2011, this project ended and we recorded an additional pre-tax loss of approximately $0.2 million.

Note 14 — Business Segment Information

In 2012, our operations were conducted through the following lines of business: contracting services and oil and gas. We have disaggregated our contracting services operations into two reportable segments which consist of Contracting Services and Production Facilities. Our Contracting Services segment includes well intervention, robotics and subsea construction operations (see Note 2 for disclosures regarding the planned dispositions of our subsea construction vessels and related assets). The Production Facilities segment includes our consolidated investment in the HP I and Kommandor LLC as well as our equity investments in Deepwater Gateway and Independence Hub that are accounted for under the equity method of accounting. All material intercompany transactions between the segments have been eliminated. In December 2012, we announced a definitive agreement for the sale of ERT. In February 2013, we sold ERT. As a result, we have presented the assets and liabilities included in the sale of ERT and the historical operating results of our former Oil and Gas segment as discontinued operations in the accompanying consolidated financial statements. See Note 3 for additional information regarding our discontinued operations.

We evaluate our performance based on operating income and income before income taxes of each segment. Segment assets are comprised of all assets attributable to the reportable segment. Certain financial data by reportable segment are summarized as follows (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Revenues —			
Contracting Services	$899,793	$738,235	$780,339
Production Facilities	80,091	75,460	117,300
Intercompany elimination	(133,775)	(111,695)	(123,170)
Total	$846,109	$702,000	$774,469
Income (loss) from operations —			
Contracting Services	$(7,702)	$107,013	$77,391
Production Facilities	40,082	38,404	63,863

Corporate	(92,985)	(82,470)	(71,080)
Intercompany elimination	(7,878)	93	(19,095)
Total	$(68,483)	$63,040	$51,079

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	Year Ended December 31,		
	2012	2011	2010
Net interest expense and other —			
Contracting Services	$702	$765	$1,299
Production Facilities	365	442	865
Corporate and eliminations	64,845	72,435	64,474
Total	$65,912	$73,642	$66,638
Equity in earnings of equity investments	$8,434	$22,215	$19,469
Income (loss) before income taxes —			
Contracting Services	$(8,529)	$97,798	$72,459
Production Facilities	48,276	58,064	86,100
Corporate and eliminations	(165,708)	(154,812)	(156,889)
Total	$(125,961)	$1,050	$1,670
Income tax provision (benefit) —			
Contracting Services	$(15,707)	$29,235	$42,828
Production Facilities	15,784	19,233	29,049
Corporate and eliminations	(59,235)	(85,274)	(52,711)
Total	$(59,158)	$(36,806)	$19,166
Identifiable assets —			
Contracting Services	$1,982,822	$2,023,251	$1,872,141
Production Facilities	503,531	534,776	512,990
Discontinued operations	900,227	1,024,320	1,206,889
Total	$3,386,580	$3,582,347	$3,592,020
Capital expenditures —			
Contracting Services	$322,216	$69,259	$65,949
Production Facilities	823	30,896	56,269
Total	$323,039	$100,155	$122,218
Depreciation and amortization —			
Contracting Services	$77,442	$73,291	$66,333
Production Facilities	16,828	14,935	9,907
Corporate and eliminations	2,931	2,962	5,638
Total	$97,201	$91,188	$81,878

Intercompany segment revenues during the years ended December 31, 2012, 2011 and 2010 are as follows (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Contracting Services	$87,718	$65,638	$109,012
Production Facilities	46,057	46,057	14,158
Total	$133,775	$111,695	$123,170

Intercompany segment profits (losses) (which only relate to intercompany capital projects) during the years ended December 31, 2012, 2011 and 2010 are as follows (in thousands):

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	Year Ended December 31,		
	2012	2011	2010
Contracting Services	$8,053	$104	$15,655
Production Facilities	(175)	(197)	3,457
Total	$7,878	$(93)	$19,112

Revenue associated with our continuing operations by individually significant country during the years ended December 31, 2012, 2011 and 2010 is as follows (in thousands):

	Year Ended December 31,		
	2012	2011	2010
United States	$281,308	$316,869	$402,228
United Kingdom	345,074	275,499	198,011
Other	219,727	109,632	174,230
Total	$846,109	$702,000	$774,469

We include the property and equipment, net in the country in which it is legally owned. The following table provides our property and equipment, net of accumulated depreciation, associated with our continuing operations by individually significant country (in thousands):

	Year Ended December 31,		
	2012	2011	2010
United States	$1,180,586	$1,163,320	$1,162,217
United Kingdom	304,062	281,430	275,012
Other	1,227	14,919	15,613
Total	$1,485,875	$1,459,669	$1,452,842

Note 15 — Allowance Accounts

The following table sets forth the activity in our valuation accounts for each of the three years in the period ended December 31, 2012 (in thousands):

	Allowance for Uncollectible Accounts	Deferred Tax Asset Valuation Allowance
Balance at December 31, 2009	$ 5,105	$ —
Additions (1)	4,108	8,497
Deductions (2)	(4,753)	—
Balance at December 31, 2010	4,460	8,497
Additions (3)	61	5,813
Deductions	(521)	—
Balance at December 31, 2011	4,000	14,310
Additions (4)	1,257	2,081
Deductions	(105)	—

Balance at December 31, 2012	$ 5,152	$ 16,391

(1) Amounts include a $4.0 million bad debt allowance related to a large international construction contract and a $7.3 million increase in valuation allowance related to our WOSEA operations with the remaining allowance being related to our acquisition of the remaining 50% of the Camelot field in the United Kingdom.

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(2) Includes the $3.7 million of bad debt expense related to settlement of third party claims related to a terminated international construction contract in Australia (Note 13).

(3) The increase in valuation allowance includes $4.9 million related to our WOSEA and $0.9 million to our oil and gas operations in the United Kingdom.

(4) The increase in valuation allowance includes $2.0 million related to our WOSEA operations and $0.1 million to our oil and gas operations in the United Kingdom. WOSEA has a full valuation allowance against its deferred tax asset balance.

See Note 2 for a detailed discussion regarding our accounting policy on accounts receivable and allowance for uncollectible accounts and Note 8 for a detailed discussion of the valuation allowance related to our deferred tax assets.

Note 16 — Supplemental Oil and Gas Disclosures (Unaudited)

As previously disclosed, we sold ERT on February 6, 2013. The following oil and gas disclosures concerning our costs and estimated proved reserves are required and provided for your information as we continued to own the oil and gas properties at December 31, 2012. Our only remaining involvement in the oil and gas business is the substantially-abandoned Camelot field in the U.K. (Note 3) and our remaining overriding royalty interest in the Wang well (Green Canyon Block 237) and certain other future exploration prospects.

Capitalized Costs

Aggregate amounts of capitalized costs relating to our oil and gas activities and the aggregate amount of related accumulated depletion, depreciation and amortization as of the dates indicated are presented below (in thousands):

	2012	2011
Unproved oil and gas properties	$51,513	$50,389
Proved oil and gas properties	2,453,667	2,516,363
Total oil and gas properties	2,505,180	2,566,752
Accumulated depletion, depreciation and amortization	(1,717,314)	(1,695,105)
Net capitalized costs	$787,866	$871,647

Included in the depreciable basis of our proved oil and gas properties is the estimate of our proportionate share of asset retirement obligations relating to these properties which are also reflected as asset retirement obligations within our non-current liabilities of discontinued operations (Note 3). At December 31, 2012 and 2011, our oil and gas asset retirement obligations totaled $203.9 million and $254.4 million, respectively.

Costs Incurred in Oil and Gas Producing Activities

The following table reflects the costs incurred in oil and gas property acquisition and development activities, including estimated asset retirement obligations, during the years indicated (in thousands):

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	Year Ended December 31,		
	2012	2011	2010
Property acquisition costs:			
Proved properties	$ —	$ —	$ —
Unproved properties	—	41	364
Total property acquisition costs	—	41	364
Exploration costs	135,311	2,513	1,362
Development costs (1)	17,344	126,196	53,002
Asset retirement costs (2)	59,715	46,446	25,356
Total costs incurred	$212,370	$175,196	$80,084

(1) Development costs include costs incurred to obtain access to proved reserves to drill and equip development wells.

(2) Asset retirement costs include $15.5 million, $20.0 million, $0.9 million, respectively, associated with the Camelot field in the United Kingdom during the years ended December 31, 2012, 2011 and 2010.

Estimated Quantities of Proved Oil and Gas Reserves

We have employed full-time experienced reserve engineers and geologists who are responsible for determining proved reserves in compliance with SEC guidelines. Our engineering reserve estimates were prepared based upon interpretation of production performance data and sub-surface information obtained from the drilling of existing wells. ERT's Vice President — Reservoir Engineering and Business Development, our internal reservoir engineers and geologists analyzed 100% of our significant United States oil and gas fields (40 fields as of December 31, 2012). We consider any field with discounted future net revenues of 1% or greater of the total discounted future net revenues of all our fields to be significant.

We used our internal estimates of proved reserves for the related disclosures at December 31, 2012. The reports to estimate our proved reserves at December 31, 2011 and 2010 were prepared by an independent reservoir engineering firm.

The following table presents our net ownership interest in proved oil reserves (MBbls) and proved gas reserves, including natural gas liquids (MMcf):

	Oil	Gas	Total (MBOE)
Total proved reserves at December 31, 2009 (1)	29,727	399,315	96,280
Revision of previous estimates (1), (2)	(1,555)	(144,954)	(25,714)
Production	(3,354)	(27,097)	(7,870)
Purchases of reserves in place	—	—	—
Sales of reserves in place	—	—	—
Extensions and discoveries	—	—	—
Total proved reserves at December 31, 2010	24,818	227,264	62,696
Revision of previous estimates (3)	3,475	(108,947)	(14,683)
Production	(5,785)	(17,458)	(8,694)
Purchases of reserves in place	—	—	—
Sales of reserves in place	(205)	(4,109)	(890)
Extensions and discoveries	386	271	431
Total proved reserves at December 31, 2011	22,689	97,021	38,860

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	Oil	Gas	Total (MBOE)
Total proved reserves at December 31, 2011	22,689	97,021	38,860
Revision of previous estimates (4)	647	(12,926)	(1,508)
Production	(4,725)	(11,361)	(6,619)
Purchases of reserves in place	—	—	—
Sales of reserves in place	(75)	(3,473)	(654)
Extensions and discoveries	1,434	4,026	2,105
Total proved reserves at December 31, 2012	19,970	73,287	32,184
Total proved developed reserves as of:			
December 31, 2009	14,850	124,763	35,644
December 31, 2010	11,796	75,664	24,407
December 31, 2011	12,754	59,859	22,731
December 31, 2012	12,431	43,475	19,677

(1) Total proved gas reserves at December 31, 2009 include 12 Bcf associated with the Camelot field in the United Kingdom. The U.K. reserves were reversed in 2010 as a result of our decision to no longer develop the field and to pursue its full abandonment.

(2) Includes an approximate 1.8 MMBbls decrease in oil reserve and an approximate 131 Bcf decrease in gas reserve as reflected in our independent petroleum engineer reserve report at June 30, 2010 resulting from a combination of factors, including well performance issues at certain producing fields, most notably the Bushwood field at Garden Banks Blocks 462/463/506/507, as well as changes in the field economics of other oil and gas properties. The changes in field economics primarily affected properties that were either close to the end of their production life or in which we had proved undeveloped reserves, which would have been required to be developed in the near term. The decision not to develop these properties in light of these economic changes was also driven by our desire to pursue potential alternatives to divest all or a portion of our oil and gas assets and the increasing uncertainties about future oil and gas operations in the Gulf of Mexico as a result of the Macondo well control incident.

(3) The positive revision in oil reserves reflects the better than expected production volumes primarily from the Phoenix field at Green Canyon Blocks 236, 237, 238 and 282 since it began production in October 2010. The decrease in gas reserve primarily represents a reclassification of estimated proved reserves to the probable reserve category following the receipt and interpretation of new seismic data. The field with the largest shift from the proved to probable reserve category was the Bushwood field, where we reclassified approximately 87 Bcf at December 31, 2011.

(4) Decrease primarily represents revisions at several gas fields due to well performance and future capital investment plans.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following table reflects the standardized measure of discounted future net cash flows relating to our interest in proved oil and gas reserves (in thousands):

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	United States	United Kingdom	Total
As of December 31, 2012 —			
Future cash inflows	$2,341,354	$ —	$2,341,354
Future costs:			
Production	509,408	—	509,408
Development and abandonment	507,074	2,897	509,971
Total future costs	1,016,482	2,897	1,019,379
Future net cash flows before income taxes	1,324,872	(2,897)	1,321,975
Future income tax expense	330,630	—	330,630
Future net cash flows	994,242	(2,897)	991,345
Discount at 10% annual rate	153,032	—	153,032
Standardized measure of discounted future net cash flows	$841,210	$(2,897)	$838,313
As of December 31, 2011 —			
Future cash inflows	$2,811,956	$ —	$2,811,956
Future costs:			
Production	419,617	—	419,617
Development and abandonment	557,323	27,300	584,623
Total future costs	976,940	27,300	1,004,240
Future net cash flows before income taxes	1,835,016	(27,300)	1,807,716
Future income tax expense	477,630	—	477,630
Future net cash flows	1,357,386	(27,300)	1,330,086
Discount at 10% annual rate	266,954	—	266,954
Standardized measure of discounted future net cash flows	$1,090,432	$(27,300)	$1,063,132
As of December 31, 2010 —			
Future cash inflows	$2,925,744	$ —	$2,925,744
Future costs:			
Production	583,050	—	583,050
Development and abandonment	590,870	12,200	603,070
Total future costs	1,173,920	12,200	1,186,120
Future net cash flows before income taxes	1,751,824	(12,200)	1,739,624
Future income tax expense	430,153	—	430,153
Future net cash flows	1,321,671	(12,200)	1,309,471
Discount at 10% annual rate	318,404	—	318,404
Standardized measure of discounted future net cash flows	$1,003,267	$(12,200)	$991,067

Future cash inflows are computed by applying the appropriate average 12-month commodity prices as based on the price of oil and natural gas on the first day of each month during the year, adjusted for location and quality differentials on a property-by-property basis, to year-end quantities of proved reserves. The discounted future cash flow estimates do not include the effects of our derivative instruments. See the following table for base prices used in determining the standardized measure:

	Year Ended December 31,		
	2012	2011	2010
Oil price per Bbl	$104.85	$105.35	$77.55
Natural gas price per Mcf	$3.38	$4.34	$4.40

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The future income tax expense was computed by applying the appropriate year-end statutory rates, with consideration of future tax rates already legislated, to the future pretax net cash flows less the tax basis of the associated properties. Future net cash flows are discounted at the prescribed rate of 10%. We caution that actual future net cash flows may vary considerably from these estimates. Although our estimates of total proved reserves, development costs and production rates were based on the best information available, the development and production of oil and gas reserves may not occur in the periods assumed. Actual prices realized, costs incurred and production quantities may vary significantly from those assumed. Therefore, such estimated future net cash flow computations should not be considered to represent our estimate of the expected revenues or the current value of existing proved reserves.

Changes in Standardized Measure of Discounted Future Net Cash Flows

Principal changes in the standardized measure of discounted future net cash flows attributable to our proved oil and gas reserves are as follows (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Standardized measure, beginning of year	$1,063,132	$991,067	$991,060
Changes during the year:			
Sales, net of production costs	(379,910)	(516,895)	(294,212)
Net change in prices and production costs	(242,037)	414,426	577,687
Changes in future development costs	(65,854)	(108,007)	84,907
Development costs incurred (1)	149,702	168,005	55,646
Accretion of discount	147,157	131,464	129,083
Net change in income taxes	101,720	(54,613)	(41,115)
Purchases of reserves in place	—	—	—
Extensions and discoveries	110,655	29,479	—
Sales of reserves in place	(6,096)	(14,324)	—
Net change due to revision in quantity estimates	28,627	(186,197)	(422,987)
Changes in production rates (timing) and other	(68,783)	208,727	(89,002)
Total	(224,819)	72,065	7
Standardized measure, end of year	$838,313	$1,063,132	$991,067

(1) Includes incurred asset retirement obligation costs.

Note 17 — Derivative Instruments and Hedging Activities

Derivatives designated as hedging instruments as defined in FASB Codification Topic No. 815 Derivatives in Hedging are as follows (in thousands):

	As of December 31, 2012		As of December 31, 2011	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Asset Derivatives:				
Natural gas contracts	Other current assets	$ —	Other current assets	$12,957
Oil contracts	Other current assets	—	Other current assets	8,567
Natural gas contracts	Other assets, net	—	Other assets, net	857
Interest rate swaps	Other assets, net	—	Other assets, net	327
		$ —		$22,708

Liability Derivatives:				
Oil contracts	Accrued liabilities	$ —	Accrued liabilities	$886
Interest rate swaps	Accrued liabilities	—	Accrued liabilities	202
Oil contracts	Other long-term liabilities	—	Other long-term liabilities	1,712
		$ —		$2,800

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Derivatives that were not designated as hedging instruments are as follows (in thousands):

	As of December 31, 2012		As of December 31, 2011	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Asset Derivatives:				
Oil contracts	Other current assets	$5,800	Other current assets	$ —
Foreign exchange forwards	Other current assets	146	Other current assets	55
		$5,946		$55
Liability Derivatives:				
Oil contracts	Accrued liabilities	$15,777	Accrued liabilities	$ —
Interest rate swaps	Accrued liabilities	489	Accrued liabilities	—
Foreign exchange forwards	Accrued liabilities	—	Accrued liabilities	159
Interest rate swaps	Other long-term liabilities	32	Other long-term liabilities	—
		$16,298		$159

As a result of recent declines in natural gas production from our properties, including the effects Hurricane Isaac had on our properties in August 2012, sales of certain of our natural gas producing properties and the continued deferral of initiating production from our Nancy well in the Bushwood field, we de-designated four of our natural gas derivative contracts as hedging instruments. We concluded that these contracts no longer qualified for hedge accounting treatment because we could no longer forecast that we would have the necessary production volumes to cover the volumes in these contracts. All four of these contracts were settled as of December 31, 2012. The mark-to-market adjustments associated with these contracts are recorded as a component of “Income (loss) from discontinued operations, net of tax” in the accompanying consolidated statements of operations.

As a result of the announcement of the sale of ERT, we de-designated all of our remaining oil and natural gas derivative contracts as hedging instruments. In addition, under the terms of our Credit Agreement (Note 7), we are required to use at a minimum 60% of the after-tax proceeds from the sales of the Caesar, the Express and ERT to make payments to reduce our Term Loan debt and borrowings under the Revolving Credit Facility. Because it is probable that we will pay off the Term Loan debt before the expiration of our interest rate swaps, we also concluded that the swaps no longer qualified as cash flow hedges. At December 31, 2012, we recorded the mark-to-market adjustments for these derivatives to reflect the changes in their fair values and to recognize amounts previously recorded in accumulated other comprehensive income (loss) and related deferred taxes into earnings. The mark-to-market adjustments related to our commodity derivative contracts and interest rate swaps are reflected in “Non-hedge loss on commodity derivative contracts” and “Other income (expense), net”, respectively, in the accompanying consolidated statements of operations. In February 2013, we settled all of our remaining commodity derivative contracts and interest rate swap contracts for approximately $22.5 million and $0.6 million, respectively.

The following tables present the impact that derivative instruments designated as cash flow hedges had on our accumulated comprehensive income (loss) and our consolidated statements of operations for the years ended December 31, 2012, 2011 and 2010 (in thousands). The amount of any ineffectiveness associated with our oil contracts was immaterial for the years ended December 31, 2012, 2011 and 2010. These amounts are reflected in “Income (loss) from discontinued operations, net of tax” in the accompanying consolidated statements of operations. Ineffectiveness associated with our interest rate swaps was immaterial for all periods presented.

Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)

	Year Ended December 31,		
	2012	2011	2010
Oil and natural gas commodity contracts	$(12,860)	$28,749	$(6,486)
Interest rate swaps	(81)	1,294	(1,213)
	$(12,941)	$30,043	$(7,699)

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	Location of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) Year Ended December 31,		
		2012	2011	2010
Oil and natural gas commodity contracts	Income (loss) from discontinued operations, net of tax	$3,184	$(21,659)	$25,575
Interest rate swaps	Net interest expense	(523)	(2,010)	(1,849)
		$2,661	$(23,669)	$23,726

The following table presents the impact that derivative instruments not designated as hedges had on our consolidated statement of operations for the years ended December 31, 2012, 2011 and 2010 (in thousands):

	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives Year Ended December 31,		
		2012	2011	2010
Oil and natural gas commodity contracts	Income (loss) from discontinued operations, net of tax	$5,550	$ —	$1,088
Oil and natural gas commodity contracts	Non-hedge loss on commodity derivative contracts	(10,507)	—	—
Interest rate swaps	Other income (expense), net	(567)	—	—
Foreign exchange forwards	Other income (expense), net	411	249	(2,560)
		$(5,113)	$249	$(1,472)

Note 18 — Quarterly Financial Information (Unaudited)

The offshore marine construction industry in the Gulf of Mexico is highly seasonal as a result of weather conditions and the timing of capital expenditures by oil and gas companies. Historically, a substantial portion of our services has been performed during the summer and fall months. As a result, historically a disproportionate portion of our revenues and net income is earned during such period. The following is a summary of consolidated quarterly financial information for 2012 and 2011 (in thousands, except per share data):

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2012				
Net revenues (1)	$ 229,842	$ 197,461	$ 217,110	$ 201,696
Gross profit (loss) (2)	72,483	28,438	57,919	(108,925)
Net income (loss)	65,737	44,651	14,875	(171,560)
Net income (loss) applicable to common shareholders:				
Income (loss) from continuing operations	$ 16,874	$ 2,425	$ 10,362	$ (99,679)
Income (loss) from discontinued operations (3)	48,853	42,216	4,503	(71,888)
Net income (loss) applicable to common shareholders	$ 65,727	$ 44,641	$ 14,865	$ (171,567)

Basic earnings (loss) per common share:				
Income (loss) from continuing operations	$ 0.16	$ 0.02	$ 0.10	$ (0.95)
Income (loss) from discontinued operations	0.46	0.40	0.04	(0.69)
Basic earnings (loss) per common share	$ 0.62	$ 0.42	$ 0.14	$ (1.64)
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	$ 0.16	$ 0.02	$ 0.10	$ (0.95)
Income (loss) from discontinued operations	0.46	0.40	0.04	(0.69)
Diluted earnings (loss) per common share	$ 0.62	$ 0.42	$ 0.14	$ (1.64)

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	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2011				
Net revenues (4)	$ 122,748	$ 165,861	$ 213,278	$ 200,113
Gross profit (5)	14,395	44,043	64,972	26,273
Net income (6)	25,867	41,323	46,026	16,763
Net income applicable to common shareholders:				
Income (loss) from continuing operations	$ (9,315)	$ 10,547	$ 15,999	$ 17,487
Income (loss) from discontinued operations	35,172	30,766	30,017	(734)
Net income applicable to common shareholders	$ 25,857	$ 41,313	$ 46,016	$ 16,753
Basic earnings per common share:				
Income (loss) from continuing operations	$ (0.09)	$ 0.10	$ 0.15	$ 0.17
Income (loss) from discontinued operations	0.33	0.29	0.28	(0.01)
Basic earnings per common share	$ 0.24	$ 0.39	$ 0.43	$ 0.16
Diluted earnings per common share:				
Income (loss) from continuing operations	$ (0.09)	$ 0.10	$ 0.15	$ 0.17
Income (loss) from discontinued operations	0.33	0.29	0.29	(0.01)
Diluted earnings per common share	$ 0.24	$ 0.39	$ 0.44	$ 0.16

(1) Excludes revenues from discontinued operations of $178.1 million, $149.9 million, $119.1 million and $110.1 million for the quarters ended March 31, June 30, September 30 and December 31, 2012.

(2) Excludes gross profit (loss) from discontinued operations of $89.2 million, $64.8 million, $27.8 million and $(102.6) million for the quarters ended March 31, June 30, September 30 and December 31, 2012. Includes impairment charges totaling $14.6 million in the second quarter of 2012, $4.6 million in the third quarter of 2012 and $158.0 million in the fourth quarter of 2012 (Note 2).

(3) Our net loss in the fourth quarter of 2012 includes a $138.6 million impairment charge associated with the sale of ERT (Note 3).

(4) Excludes revenues from discontinued operations of $168.9 million, $172.5 million, $159.2 million and $196.1 million for the quarters ended March 31, June 30, September 30 and December 31, 2011.

(5) Excludes gross profit from discontinued operations of $62.7 million, $56.2 million, $57.3 million and $4.8 million for the quarters ended March 31, June 30, September 30 and December 31, 2011. The fourth quarter includes a $6.6 million impairment charge to reduce our Australian well intervention equipment to its estimated fair value at December 31, 2011.

(6) Our net income in the fourth quarter of 2011 includes a $10.6 million other than temporary impairment loss on our equity investment in our Australian joint venture (Note 5). The fourth quarter also includes a $31.3 million tax benefit related to reorganization of our Australian well intervention operations.

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Note 19 — Condensed Consolidated Guarantor and Non-Guarantor Financial Information

The payment of our obligations under the Senior Unsecured Notes is guaranteed by all of our restricted domestic subsidiaries (“Subsidiary Guarantors”) except for Cal Dive I-Title XI, Inc. Each of these Subsidiary Guarantors is included in our consolidated financial statements and has fully and unconditionally guaranteed the Senior Unsecured Notes on a joint and several basis. As a result of these guaranty arrangements, we are required to present the following condensed consolidating financial information. The accompanying guarantor financial information is reported based on the equity method of accounting for all periods presented. Under this method, investments in subsidiaries are recorded at cost and adjusted for our share in the subsidiaries’ cumulative results of operations, capital contributions and distributions and other changes in equity. Elimination entries primarily relate to the elimination of investments in subsidiaries and associated intercompany balances and transactions.

HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING BALANCE SHEETS
(in thousands)

	As of December 31, 2012				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$381,599	$4,436	$51,065	$ —	$ 437,100
Accounts receivable, net	39,203	37,378	75,652	—	152,233
Unbilled revenue	13,959	875	19,006	—	33,840
Income taxes receivable	24,611	—	306	(10,716)	14,201
Other current assets	54,588	16,418	11,696	31	82,733
Current assets of discontinued operations	—	84,000	—	—	84,000
Total current assets	513,960	143,107	157,725	(10,685)	804,107
Intercompany	(154,756)	352,210	(125,889)	(71,565)	—
Property and equipment, net	208,190	351,746	930,556	(4,617)	1,485,875
Other assets:					
Equity investments in unconsolidated affiliates	—	—	167,599	—	167,599
Equity investments in affiliates	1,762,359	53,461	—	(1,815,820)	—
Goodwill	—	45,107	17,828	—	62,935
Other assets, net	47,355	130	34,848	(32,496)	49,837
Due from subsidiaries/parent	294,461	485,096	—	(779,557)	—
Non-current assets of discontinued operations	—	816,227	—	—	816,227
Total assets	$2,671,569	$2,247,084	$1,182,667	$ (2,714,740)	$ 3,386,580
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$45,784	$17,229	$29,385	$ —	$ 92,398
Accrued liabilities	117,902	26,019	17,593	—	161,514
Income taxes payable	—	26,618	—	(26,618)	—
Current maturities of long-term debt	11,487	—	5,120	—	16,607

Current liabilities of discontinued operations	—	182,527	—	—	182,527
Total current liabilities	175,173	252,393	52,098	(26,618)	453,046
Long-term debt	902,453	—	100,168	—	1,002,621
Deferred tax liabilities	168,688	86,925	109,171	(5,547)	359,237
Other long-term liabilities	1,453	3,086	486	—	5,025
Due to parent	—	—	323,049	(323,049)	—
Non-current liabilities of discontinued operations	—	147,237	—	—	147,237
Total liabilities	1,247,767	489,641	584,972	(355,214)	1,967,166
Convertible preferred stock	—	—	—	—	—
Total equity	1,423,802	1,757,443	597,695	(2,359,526)	1,419,414
Total liabilities and shareholders' equity	$2,671,569	$2,247,084	$1,182,667	$ (2,714,740)	$ 3,386,580

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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING BALANCE SHEETS
(in thousands)

	As of December 31, 2011				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$495,484	$2,432	$48,547	$ —	$ 546,463
Accounts receivable, net	79,290	26,885	41,724	—	147,899
Unbilled revenue	10,530	155	26,690	—	37,375
Income taxes receivable	80,388	—	—	(80,388)	—
Other current assets	68,627	20,624	10,159	(5,826)	93,584
Current assets of discontinued operations	—	118,921	—	—	118,921
Total current assets	734,319	169,017	127,120	(86,214)	944,242
Intercompany	(147,187)	315,821	(102,826)	(65,808)	—
Property and equipment, net	230,946	550,668	682,899	(4,844)	1,459,669
Other assets:					
Equity investments in unconsolidated affiliates	—	—	175,656	—	175,656
Equity investments in affiliates	1,952,392	37,239	—	(1,989,631)	—
Goodwill	—	45,107	17,108	—	62,215
Other assets, net	53,425	2,712	16,809	(37,780)	35,166
Due from subsidiaries/parent	64,655	430,496	—	(495,151)	—
Non-current assets of discontinued operations	—	905,399	—	—	905,399
Total assets	$2,888,550	$2,456,459	$916,766	$ (2,679,428)	$ 3,582,347
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$39,280	$9,626	$25,013	$ —	$ 73,919
Accrued liabilities	115,921	3,841	26,350	—	146,112
Income taxes payable	—	97,692	217	(96,616)	1,293
Current maturities of long-term debt	3,000	—	10,377	(5,500)	7,877
Current liabilities of discontinued operations	—	166,975	—	—	166,975
Total current liabilities	158,201	278,134	61,957	(102,116)	396,176
Long-term debt	1,042,155	—	105,289	—	1,147,444
Deferred tax liabilities	231,255	88,625	103,552	(5,822)	417,610
Other long-term liabilities	4,150	4,647	571	—	9,368
Due to parent	—	—	98,285	(98,285)	—
Non-current liabilities of discontinued operations	—	161,208	—	—	161,208
Total liabilities	1,435,761	532,614	369,654	(206,223)	2,131,806
Convertible preferred stock	1,000	—	—	—	1,000
Total equity	1,451,789	1,923,845	547,112	(2,473,205)	1,449,541

Total liabilities and shareholders' equity	$2,888,550	$2,456,459	$916,766	$ (2,679,428)	$ 3,582,347

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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
AND COMPREHENSIVE INCOME (LOSS)
(in thousands)

	Year Ended December 31, 2012				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$90,552	$404,628	$464,331	$ (113,402)	$ 846,109
Cost of sales	111,531	444,956	351,283	(111,576)	796,194
Gross profit (loss)	(20,979)	(40,328)	113,048	(1,826)	49,915
Loss on sale of assets, net	—	(13,475)	(1)	—	(13,476)
Non-hedge loss on commodity derivative contracts	—	(10,507)	—	—	(10,507)
Selling, general and administrative expenses	(53,539)	(22,782)	(20,018)	1,924	(94,415)
Income (loss) from operations	(74,518)	(87,092)	93,029	98	(68,483)
Equity in earnings of investments	(12,264)	16,222	8,434	(3,958)	8,434
Net interest expense and other	(59,759)	392	(6,517)	(28)	(65,912)
Income (loss) before income taxes	(146,541)	(70,478)	94,946	(3,888)	(125,961)
Income tax provision (benefit)	(96,328)	24,186	12,951	33	(59,158)
Income (loss) from continuing operations	(50,213)	(94,664)	81,995	(3,921)	(66,803)
Income (loss) from discontinued operations, net of tax	(1,621)	25,305	—	—	23,684
Net income (loss) applicable to Helix	(51,834)	(69,359)	81,995	(3,921)	(43,119)
Net income applicable to noncontrolling interests	—	—	—	(3,178)	(3,178)
Preferred stock dividends	(37)	—	—	—	(37)
Net income (loss) applicable to Helix common shareholders	$(51,871)	$(69,359)	$81,995	$ (7,099)	$ (46,334)
Total comprehensive income (loss) applicable to Helix common shareholders	$(51,952)	$(82,219)	$89,260	$ (7,073)	$ (51,984)

	Year Ended December 31, 2011				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$84,748	$362,648	$367,114	$ (112,510)	$ 702,000
Cost of sales	72,902	281,267	309,429	(111,281)	552,317
Gross profit	11,846	81,381	57,685	(1,229)	149,683
Loss on sale of assets, net	(6)	—	—	—	(6)
Selling, general and administrative expenses	(74,205)	(25,963)	12,101	1,430	(86,637)
Income (loss) from operations	(62,365)	55,418	69,786	201	63,040
Equity in earnings of investments	262,990	7,340	22,215	(270,330)	22,215

Other than temporary loss on equity investments	—	—	(10,563)	—	(10,563)
Net interest expense and other	(157,546)	(6,787)	67,181	23,510	(73,642)
Income (loss) before income taxes	43,079	55,971	148,619	(246,619)	1,050
Income tax provision (benefit)	(63,242)	18,181	8,186	69	(36,806)
Income (loss) from continuing operations	106,321	37,790	140,433	(246,688)	37,856
Income from discontinued operations, net of tax	—	95,221	—	—	95,221
Net income (loss) applicable to Helix	106,321	133,011	140,433	(246,688)	133,077
Net income applicable to noncontrolling interests	—	—	—	(3,098)	(3,098)
Preferred stock dividends	(40)	—	—	—	(40)
Net income (loss) applicable to Helix common shareholders	$106,281	$133,011	$140,433	$ (249,786)	$ 129,939
Total comprehensive income (loss) applicable to Helix common shareholders	$107,575	$161,760	$140,214	$ (250,569)	$ 158,980

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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
AND COMPREHENSIVE INCOME (LOSS)
(in thousands)

	Year Ended December 31, 2010				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$183,147	$376,134	$334,726	$ (119,538)	$ 774,469
Cost of sales	124,722	287,709	302,051	(104,830)	609,652
Gross profit	58,425	88,425	32,675	(14,708)	164,817
Goodwill impairment	—	—	(16,743)	—	(16,743)
Gain on sale of assets, net	3,159	—	5,959	—	9,118
Selling, general and administrative expenses	(67,165)	(18,268)	(22,482)	1,802	(106,113)
Loss from operations	(5,581)	70,157	(591)	(12,906)	51,079
Equity in earnings of investments	(60,443)	8,473	19,469	51,970	19,469
Other than temporary loss on equity investments	(2,240)	—	—	—	(2,240)
Net interest expense and other	(59,522)	(1,991)	(5,125)	—	(66,638)
Income (loss) before income taxes	(127,786)	76,639	13,753	39,064	1,670
Income tax provision (benefit)	(9,175)	23,465	9,405	(4,529)	19,166
Income (loss) from continuing operations	(118,611)	53,174	4,348	43,593	(17,496)
Loss from discontinued operations, net of tax	—	(106,657)	—	—	(106,657)
Net income (loss) applicable to Helix	(118,611)	(53,483)	4,348	43,593	(124,153)
Net income applicable to noncontrolling interests	—	—	—	(2,835)	(2,835)
Preferred stock dividends	(114)	—	—	—	(114)
Net income (loss) applicable to Helix common shareholders	$(118,725)	$(53,483)	$4,348	$ 40,758	$ (127,102)
Total comprehensive income (loss) applicable to Helix common shareholders	$(119,051)	$(59,969)	$(5,653)	$ 40,754	$ (143,919)

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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31, 2012				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flows from operating activities:					
Net income (loss), including noncontrolling interests	$(51,834)	$(69,359)	$81,995	$ (3,921)	$ (43,119)
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by (used in) operating activities:					
Equity in earnings of affiliates	12,264	(16,222)	—	3,958	—
Other adjustments	106,022	126,672	6,349	(19,856)	219,187
Cash provided by (used in) operating activities	66,452	41,091	88,344	(19,819)	176,068
Cash provided by discontinued operations	1,621	274,809	—	—	276,430
Net cash provided by (used in) operating activities	68,073	315,900	88,344	(19,819)	452,498
Cash flows from investing activities:					
Capital expenditures	(2,422)	(38,197)	(282,420)	—	(323,039)
Distributions from equity investments, net	—	—	7,797	—	7,797
Proceeds from sale of assets	—	19,530	—	—	19,530
Cash used in investing activities	(2,422)	(18,667)	(274,623)	—	(295,712)
Cash used in discontinued operations	—	(120,057)	—	—	(120,057)
Net cash used in investing activities	(2,422)	(138,724)	(274,623)	—	(415,769)
Cash flows from financing activities:					
Borrowings of debt	400,000	—	—	—	400,000
Repayments of debt	(520,357)	—	(4,877)	—	(525,234)
Deferred financing costs	(7,580)	—	—	—	(7,580)
Distributions to noncontrolling interests	—	—	(5,287)	—	(5,287)
Repurchases of common stock	(7,197)	—	—	—	(7,197)
Excess tax from stock-based compensation	(1,186)	—	—	—	(1,186)
Exercise of stock options, net and other	1,252	—	—	—	1,252
Intercompany financing	(44,468)	(175,172)	199,821	19,819	—
Net cash provided by (used in) financing activities	(179,536)	(175,172)	189,657	19,819	(145,232)
Effect of exchange rate changes on cash and cash equivalents	—	—	(860)	—	(860)
Net increase (decrease) in cash and cash equivalents	(113,885)	2,004	2,518	—	(109,363)
Cash and cash equivalents:					
Balance, beginning of year	495,484	2,434	48,547	—	546,465

Balance, end of year	381,599	4,438	51,065	—	437,102
Less cash from discontinued operations, end of year	—	2	—	—	2
Cash from continuing operations, end of year	$381,599	$4,436	$51,065	$ —	$ 437,100

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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31, 2011				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flows from operating activities:					
Net income (loss), including noncontrolling interests	$106,321	$133,011	$140,433	$ (246,688)	$ 133,077
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by (used in) operating activities:					
Equity in earnings of affiliates	(262,990)	(7,340)	—	270,330	—
Other adjustments	39,860	(30,770)	40,293	198	49,581
Cash provided by (used in) operating activities	(116,809)	94,901	180,726	23,840	182,658
Cash provided by discontinued operations	—	384,498	—	—	384,498
Net cash provided by (used in) operating activities	(116,809)	479,399	180,726	23,840	567,156
Cash flows from investing activities:					
Capital expenditures	(32,417)	(55,124)	(12,613)	—	(100,154)
Distributions from equity investments, net	—	—	1,266	—	1,266
Proceeds from sale of Cal Dive common stock	3,588	—	—	—	3,588
Cash used in investing activities	(28,829)	(55,124)	(11,347)	—	(95,300)
Cash used in discontinued operations	—	(87,017)	—	—	(87,017)
Net cash used in investing activities	(28,829)	(142,141)	(11,347)	—	(182,317)
Cash flows from financing activities:					
Borrowings of debt	109,400	—	—	—	109,400
Repayments of debt	(317,485)	—	(4,645)	—	(322,130)
Deferred financing costs	(9,311)	—	—	—	(9,311)
Repurchases of common stock	(7,604)	—	—	—	(7,604)
Excess tax from stock-based compensation	(1,013)	—	—	—	(1,013)
Exercise of stock options, net and other	1,978	—	(1,215)	—	763
Intercompany financing	488,723	(338,118)	(126,765)	(23,840)	—
Net cash provided by (used in) financing activities	264,688	(338,118)	(132,625)	(23,840)	(229,895)
Effect of exchange rate changes on cash and cash equivalents	—	—	436	—	436
Net increase (decrease) in cash and cash equivalents	119,050	(860)	37,190	—	155,380
Cash and cash equivalents:					
Balance, beginning of year	376,434	3,294	11,357	—	391,085

Balance, end of year	495,484	2,434	48,547	—	546,465
Less cash from discontinued operations, end of year	—	2	—	—	2
Cash from continuing operations, end of year	$495,484	$2,432	$48,547	$ —	$ 546,463

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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31, 2010				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flows from operating activities:					
Net income (loss), including noncontrolling interests	$(118,611)	$(53,483)	$4,348	$ 43,593	$ (124,153)
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by (used in) operating activities:					
Equity in earnings of affiliates	60,443	(8,473)	—	(51,970)	—
Other adjustments	94,376	45,567	76,865	(21,283)	195,525
Cash provided by (used in) operating activities	36,208	(16,389)	81,213	(29,660)	71,372
Cash provided by discontinued operations	—	260,082	—	—	260,082
Net cash provided by (used in) operating activities	36,208	243,693	81,213	(29,660)	331,454
Cash flows from investing activities:					
Capital expenditures	(56,650)	(37,155)	(28,413)	—	(122,218)
Distributions from equity investments, net	—	—	2,286	—	2,286
Proceeds from insurance reimbursement	7,020	—	—	—	7,020
Proceeds from sale of assets	6,042	—	—	—	6,042
Cash used in investing activities	(43,588)	(37,155)	(26,127)	—	(106,870)
Cash used in discontinued operations	—	(74,686)	-	—	(74,686)
Net cash used in investing activities	(43,588)	(111,841)	(26,127)	—	(181,556)
Cash flows from financing activities:					
Repayments of debt	(4,326)	—	(4,424)	—	(8,750)
Deferred financing costs	(2,947)	—	—	—	(2,947)
Repurchases of common stock	(11,680)	—	—	—	(11,680)
Excess tax from stock-based compensation	(3,945)	—	—	—	(3,945)
Exercise of stock options, net and other	560	—	(2,517)	—	(1,957)
Intercompany financing	147,410	(131,080)	(45,990)	29,660	—
Net cash provided by (used in) financing activities	125,072	(131,080)	(52,931)	29,660	(29,279)
Effect of exchange rate changes on cash and cash equivalents	—	—	(207)	—	(207)
Net increase in cash and cash equivalents	117,692	772	1,948	—	120,412
Cash and cash equivalents:					
Balance, beginning of year	258,742	2,522	9,409	—	270,673
Balance, end of year	376,434	3,294	11,357	—	391,085
	—	1	—	—	1

Less cash from discontinued operations, end of year					
Cash from continuing operations, end of year	$376,434	$3,293	$11,357	$ —	$ 391,084

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Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

(a) Evaluation of disclosure controls and procedures. Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") as of the end of the fiscal year ended December 31, 2012. Based on this evaluation, the principal executive officer and the principal financial officer conclude that our disclosure controls and procedures were effective as of the end of the fiscal year ended December 31, 2012 to ensure that information that is required to be disclosed by us in the reports we file or submit under the Exchange Act is (i) identified, recorded, processed, summarized and reported, on a timely basis and (ii) accumulated and communicated to our management, as appropriate, to allow timely decisions regarding required disclosure.

(b) Changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Securities Exchange Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

(c) Changes in Internal Control. There was not any change in our internal control over financial reporting that occurred during the fourth quarter of fiscal 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting and the Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting thereon are set forth in Part II, Item 8 of this report on Form 10-K on page 61 and page 62, respectively.

Item 9B. Other Information

On February 19, 2013, the Board of Directors elected Clifford V. Chamblee to the position of Chief Operating Officer. Additional information regarding Mr. Chamblee can be found in Part I of this Annual Report on Form 10-K. At the same meeting, Johnny Edwards was not re-elected as Executive Vice President — Oil & Gas. Also on February 19, 2013, the Compensation Committee of the Board of Directors approved the following defined performance metrics for the 2013 Short-Term Incentive Cash Bonus Program:

- 75% based on the achievement by the Company of certain EBITDA targets;
- 15% based on Company return on capital goals; and
- 10% based on maintenance of CAPEX spending within levels approved by the Board of Directors.

On February 19, 2013, we amended the credit agreement to waive certain year end oil and gas reporting requirements and covenant compliance as a result of the sale of ERT.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Except as set forth below, the information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with our 2013 Annual Meeting of Shareholders to be held on May 7, 2013. See also "Executive Officers of the Registrant" appearing in Part I of this Report.

Code of Ethics

We have adopted a Code of Business Conduct and Ethics for all directors, officers and employees as well as a Code of Ethics for Chief Executive Officer and Senior Financial Officers specific to those officers. Copies of these documents are available at our Website www.helixesg.com under Corporate Governance. Interested parties may also request a free copy of these documents from:

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Helix Energy Solutions Group, Inc.
ATTN: Corporate Secretary
400 N. Sam Houston Parkway E., Suite 400
Houston, Texas 77060

Item 11. Executive Compensation

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with our 2013 Annual Meeting of Shareholders to be held on May 7, 2013.

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 to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with our 2013 Annual Meeting of Shareholders to be held on May 7, 2013.

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 to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with our 2013 Annual Meeting of Shareholders to be held on May 7, 2013.

Item 14. Principal Accounting Fees and Services

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection our 2013 Annual Meeting of Shareholders to be held on May 7, 2013.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(1)Financial Statements

The following financial statements included on pages 61 through 124 in this Annual Report are for the fiscal year ended December 31, 2012.

- Management's Report on Internal Control Over Financial Reporting
- Report of Independent Registered Public Accounting Firm
- Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting
- Consolidated Balance Sheets as of December 31, 2012 and 2011
- Consolidated Statements of Operations for the Years Ended December 31, 2012, 2011 and 2010
- Consolidated Statements of Comprehensive Income (Loss) for the Years Ended December 31, 2012, 2011 and 2010
- Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2012, 2011 and 2010

- Consolidated Statements of Cash Flows for the Years Ended December 31, 2012, 2011 and 2010
- Notes to Consolidated Financial Statements

All financial statement schedules are omitted because the information is not required or because the information required is in the financial statements or notes thereto.

(2)Exhibits

Pursuant to Item 601(b)(4)(iii), the Registrant agrees to forward to the commission, upon request, a copy of any instrument with respect to long-term debt not exceeding 10% of the total assets of the Registrant and its consolidated subsidiaries. Reference is made to Exhibit listing beginning on page 128 hereof.

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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.

HELIX ENERGY SOLUTIONS GROUP, INC.

By: /s/ ANTHONY TRIPODO
Anthony Tripodo
Executive Vice President and
Chief Financial Officer

February 22, 2013

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

Signature	Title	Date
/s/ OWEN KRATZ Owen Kratz	President, Chief Executive Officer and Director (principal executive officer)	February 22, 2013
/s/ ANTHONY TRIPODO Anthony Tripodo	Executive Vice President and Chief Financial Officer (principal financial officer)	February 22, 2013
/s/ LLOYD A. HAJDIK Lloyd A. Hajdik	Senior Vice President — Finance and Chief Accounting Officer (principal accounting officer)	February 22, 2013
/s/ JOHN V. LOVOI John V. Lovoi	Director	February 22, 2013
/s/ T. WILLIAM PORTER T. William Porter	Director	February 22, 2013
/s/ NANCY K. QUINN Nancy K. Quinn	Director	February 22, 2013
/s/ JAN A. RASK Jan A. Rask	Director	February 22, 2013
/s/ WILLIAM L. TRANSIER William L. Transier	Director	February 22, 2013
/s/ JAMES A. WATT James A. Watt	Director	February 22, 2013

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INDEX TO EXHIBITS

Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
3.1	2005 Amended and Restated Articles of Incorporation, as amended, of registrant.	Exhibit 3.1 to the Current Report on Form 8-K filed on March 1, 2006 (000-22739)
3.2	Second Amended and Restated By-Laws of Helix, as amended.	Exhibit 3.1 to the Current Report on Form 8-K filed on September 28, 2006 (001-32936)
4.1	Credit Agreement dated July 3, 2006 by and among Helix Energy Solutions Group, Inc., and Bank of America, N.A., as administrative agent and as lender, together with the other lender parties thereto.	Exhibit 4.1 to the Current Report on Form 8-K filed on July 5, 2006 (001-32936)
4.2	Amendment No. 1 to Credit Agreement, dated as of November 29, 2007, by and among Helix, as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto.	Exhibit 10.3 to the Current Report on Form 8-K filed on December 21, 2007 (001-32936)
4.3	Amendment No. 2 to Credit Agreement, dated as of October 9, 2009, by and among Helix, as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto.	Exhibit 10.1 to the Current Report on Form 8-K filed on October 13, 2009 (001-32936)
4.4	Amendment No. 3 to Credit Agreement, dated as of February 19, 2010, by and among Helix, as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto.	Exhibit 10.1 to the Current Report on Form 8-K filed on February 24, 2010 (001-32936)
4.5	Amendment No. 4 to Credit Agreement, dated as of June 8, 2011, by and among Helix, as borrower, Bank of America, N.A., as administrative agent, swing line lender and L/C issuer, and the lenders named thereto.	Exhibit 10.1 to the Current Report on Form 8-K filed on June 9, 2011 (001-32936)
4.6	Amendment No. 5 to Credit Agreement dated November 11, 2011 by and among Helix Energy Solutions Group, Inc., as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto.	Exhibit 4.1 to the Current Report on Form 8-K filed on March 7, 2012 (001-32936)
4.7	Amendment No. 6 to Credit Agreement, dated as of February 21, 2012 by and among Helix, as borrower, Bank of America, N.A., as administrative agent, swing line lender and L/C issuer and the lenders named thereto.	Exhibit 4.6 to the 2011 Form 10-K filed on February 24, 2012 (001-32936)
4.8	Amendment No. 7 to Credit Agreement dated September 26, 2012 by and among Helix Energy Solutions Group, Inc., as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto.	Exhibit 10.1 to the Current Report on Form 8-K filed on October 1, 2012 (001-32936)
4.9	Amendment No. 8 to Credit Agreement dated February 19, 2013 by and among Helix Energy	Filed herewith

	Solutions Group, Inc., as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto.	
4.10	Form of Common Stock certificate.	Exhibit 4.7 to the Form 8-A filed on June 30, 2006 (001-32936)
4.11	Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of August 16, 2000.	Exhibit 4.4 to the 2001 Form 10-K filed on March 28, 2002 (000-22739)
4.12	Amendment No. 1 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of January 25, 2002.	Exhibit 4.9 to the 2002 Form 10-K/A filed on April 8, 2003 (000-22739)
4.13	Amendment No. 2 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of November 15, 2002.	Exhibit 4.4 to the Form S-3 filed on February 26, 2003 (333-103451)

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Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
4.14	Amendment No. 3 Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of July 31, 2003.	Exhibit 4.12 to the 2004 Form 10-K filed on March 16, 2005 (000-22739)
4.15	Amendment No. 4 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of December 15, 2004.	Exhibit 4.13 to the 2004 Form 10-K filed on March 16, 2005 (000-22739)
4.16	Indenture relating to the 3.25% Convertible Senior Notes due 2025 dated as of March 30, 2005, between Cal Dive International, Inc. and JPMorgan Chase Bank, National Association, as Trustee.	Exhibit 4.1 to the Current Report on Form 8-K filed on April 4, 2005 (000-22739)
4.17	Form of 3.25% Convertible Senior Note due 2025.	Filed as Exhibit A to Exhibit 4.16 (000-22739)
4.18	Registration Rights Agreement dated as of March 30, 2005, between Cal Dive International, Inc. and Banc of America Securities LLC, as representative of the initial purchasers.	Exhibit 4.3 to the Current Report on Form 8-K filed on April 4, 2005 (000-22739)
4.19	Trust Indenture, dated as of August 16, 2000, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee.	Exhibit 4.1 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.20	Supplement No. 1 to Trust Indenture, dated as of January 25, 2002, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee.	Exhibit 4.2 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.21	Supplement No. 2 to Trust Indenture, dated as of November 15, 2002, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee.	Exhibit 4.3 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.22	Supplement No. 3 to Trust Indenture, dated as of December 14, 2004, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee.	Exhibit 4.4 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.23	Supplement No. 4 to Trust Indenture, dated September 30, 2005, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee.	Exhibit 4.5 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.24	Form of United States Government Guaranteed Ship Financing Bonds, Q4000 Series 4.93% Sinking Fund Bonds Due February 1, 2027.	Filed as Exhibit A to Exhibit 4.23 (000-22739)
4.25	Form of Third Amended and Restated Promissory Note to United States of America.	Exhibit 4.6 to the Current Report on Form 8-K filed on October 6, 2005 (000-22739)
4.26	Indenture, dated as of December 21, 2007, by and among Helix Energy Solutions Group, Inc., the Guarantors and Wells Fargo Bank, N.A.	Exhibit 4.1 to the Current Report on Form 8-K filed on December 21, 2007 (001-32936)
4.27	Indenture dated as of March 12, 2012 between Helix Energy Solutions Group, Inc. and The Bank of New York Mellon Trust Company, N.A., as Trustee.	Exhibit 4.1 to the Current Report on Form 8-K filed on March 12, 2012 (001-32936)

10.1 *	1995 Long Term Incentive Plan, as amended.	Exhibit 10.3 to the Form S-1 filed on September 4, 1996 (333-11399)
10.2 *	Amendment to 1995 Long Term Incentive Plan of Helix Energy Solutions Group, Inc.	Exhibit 10.2 to the 2008 Form 10-K filed on March 2, 2009 (001-32936)
10.3 *	2009 Long-Term Incentive Cash Plan of Helix Energy Solutions Group, Inc.	Exhibit 10.1 to the Current Report on Form 8-K filed on January 6, 2009 (001-32936)
10.4 *	Form of Award Letter related to the 2009 Long-Term Incentive Cash Plan.	Exhibit 10.2 to the Current Report on Form 8-K filed on January 6, 2009 (001-32936)

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Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
10.5 *	Employment Agreement between Owen Kratz and the Company dated February 28, 1999.	Exhibit 10.5 to the 1998 Form 10-K filed on March 31, 1999 (000-22739)
10.6 *	Employment Agreement between Owen Kratz and the Company dated November 17, 2008.	Exhibit 10.1 to the Current Report on Form 8-K filed on November 19, 2008 (001-32936)
10.7 *	Helix 2005 Long Term Incentive Plan, including the Form of Restricted Stock Award Agreement.	Exhibit 10.1 to the Current Report on Form 8-K filed on May 12, 2005 (000-22739)
10.8 *	Amendment to 2005 Long Term Incentive Plan of Helix Energy Solutions Group, Inc.	Exhibit 10.10 to the 2008 Form 10-K filed on March 2, 2009 (001-32936)
10.9 *	Employment Agreement between Alisa B. Johnson and the Company dated November 17, 2008.	Exhibit 10.3 to the Current Report on Form 8-K filed on November 19, 2008 (001-32936)
10.10	Registration Rights Agreement dated as of December 21, 2007 by and among Helix Energy Solutions Group, Inc., the Guarantors named therein and Banc of America Securities LLC, as representative of the Initial Purchasers.	Exhibit 10.1 to the Current Report on Form 8-K filed on December 21, 2007 (001-32936)
10.11	Purchase Agreement dated as of December 18, 2007 by and among Helix Energy Solutions Group, Inc., the Guarantors named therein and Banc of America Securities LLC, and the other Initial Purchasers named therein.	Exhibit 10.2 to the Current Report on Form 8-K filed on December 21, 2007 (001-32936)
10.12	Employment Agreement between Anthony Tripodo and the Company dated June 25, 2008.	Exhibit 10.2 to the Current Report on Form 8-K filed on June 30, 2008 (001-32936)
10.13 *	First Amendment to Employment Agreement between Anthony Tripodo and the Company dated November 17, 2008.	Exhibit 10.5 to the Current Report on Form 8-K filed on November 19, 2008 (001-32936)
10.14 *	Employment Agreement between Lloyd A. Hajdik and the Company dated November 17, 2008.	Exhibit 10.4 to the Current Report on Form 8-K filed on November 19, 2008 (001-32936)
10.15 *	Employment Agreement by and between Helix Energy Solutions Group, Inc. and Johnny Edwards dated May 11, 2011.	Exhibit 10.1 to the Current Report on Form 8-K filed on May 13, 2011 (001-32936)
10.16 *	Employment Agreement by and between Helix Energy Solutions Group, Inc. and Clifford Chamblee dated May 11, 2011.	Exhibit 10.3 to the Quarterly Report on Form 10-Q filed on July 27, 2011 (001-32936)
10.17 *	Form of Cash Award Agreement.	Exhibit 10.1 to the Current Report on Form 8-K filed on December 15, 2011 (001-32936)
10.18 *	Form of Performance Units Award Agreement.	Exhibit 10.2 to the Current Report on Form 8-K filed on December 15,

		2011 (001-32936)
10.19 *	Form of Restricted Stock Award Agreement.	Exhibit 10.3 to the Current Report on Form 8-K filed on December 15, 2011 (001-32936)
10.20	Construction contract dated as of March 12, 2012 between Helix Energy Solution Group, Inc. and Jurong Shipyard Pte Ltd.	Exhibit 10.1 to the Current Report on Form 8-K filed on March 16, 2012 (001-32936)
10.21	The MODU Sale Agreement between Helix Energy Solutions Group, Inc. and Transocean Discoverer 534 LLC dated July 23, 2012.	Exhibit 10.2 to the Quarterly Report on Form 10-Q filed on July 25, 2012 (001-32936)

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Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
10.22 *	Amended and Restated 2005 Long-Term Incentive Plan of Helix Energy Solutions Group, Inc. dated May 9, 2012.	Exhibit 10.3 to the Quarterly Report on Form 10-Q filed on July 25, 2012 (001-32936)
10.23 *	Employee Stock Purchase Plan of Helix Energy Solutions Group, Inc. dated May 9, 2012.	Exhibit 10.4 to the Quarterly Report on Form 10-Q filed on July 25, 2012 (001-32936)
10.24	The Pipelay Asset Sale Agreement between Helix Energy Solutions Group, Inc. and Coastal Trade Limited dated October 15, 2012.	Exhibit 10.1 to the Current Report on Form 8-K filed on October 17, 2012 (001-32936)
10.25	Equity Purchase Agreement dated December 12, 2012, between Helix Energy Solutions Group, Inc. and Talos Production LLC.	Exhibit 10.1 to the Current Report on Form 8-K filed on December 13, 2012 (001-32936)
10.26	Third Correction Assignment of Overriding Royalty Interest dated December 12, 2012, by and between Energy Resource Technology GOM, Inc. and OKCD Investments, Ltd.	Exhibit 10.2 to the Current Report on Form 8-K filed on December 13, 2012 (001-32936)
10.27	Form of Indemnification Agreement, by and among Talos Production LLC, Energy Resource Technology GOM, LLC, CKB Petroleum, LLC, and Helix Energy Solutions Group, Inc.	Exhibit 10.3 to the Current Report on Form 8-K filed on December 13, 2012 (001-32936)
10.28 *	Non-Competition and Non-Solicitation Agreement dated December 12, 2012, by and among Energy Resource Technology GOM, Inc., CKB Petroleum, Inc., and Johnny Edwards.	Exhibit 10.4 to the Current Report on Form 8-K filed on December 13, 2012 (001-32936)
10.29 *	First Amendment to Employment Agreement dated December 12, 2012, by and between Helix Energy Solutions Group, Inc. and Johnny Edwards.	Exhibit 10.5 to the Current Report on Form 8-K filed on December 13, 2012 (001-32936)
10.30	Amendment No. 1 to Equity Purchase Agreement dated January 27, 2013, between Helix Energy Solutions Group, Inc. and Talos Production LLC.	Exhibit 10.1 to the Current Report on Form 8-K filed on January 28, 2013 (001-32936)
10.31	Amendment No. 2 to Equity Purchase Agreement dated February 6, 2013, between Helix Energy Solutions Group, Inc. and Talos Production LLC.	Exhibit 10.1 to the Current Report on Form 8-K filed on February 12, 2013 (001-32936)
14.1	Code of Ethics for Chief Executive Officer and Senior Financial Officers.	Exhibit 14.1 to the Registrant's Current Report on Form 8-K filed on December 8, 2009 (001-32936)
21.1	List of Subsidiaries of the Company.	Filed herewith
23.1	Consent of Ernst & Young LLP.	Filed herewith
23.2	Consent of Deloitte & Touche LLP. (Deepwater Gateway L.L.C.).	Filed herewith
23.3	Consent of Deloitte & Touche LLP. (Independence Hub LLC).	Filed herewith
31.1	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer.	Filed herewith
31.2		Filed herewith

	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Anthony Tripodo, Chief Financial Officer.	
32.1	Certification of Helix's Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes — Oxley Act of 2002.	Furnished herewith

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Exhibits	Description	Filed or Furnished Herewith or Incorporated by Reference from the Following Documents (Registration or File Number)
101.INS	XBRL Instance Document.	Furnished herewith
101.SCH	XBRL Schema Document.	Furnished herewith
101.CAL	XBRL Calculation Linkbase Document.	Furnished herewith
101.PRE	XBRL Presentation Linkbase Document.	Furnished herewith
101.DEF	XBRL Definition Linkbase Document.	Furnished herewith
101.LAB	XBRL Label Linkbase Document.	Furnished herewith

* Management contracts or compensatory plans or arrangements