HELIX ENERGY SOLUTIONS GROUP INC
Form 10-K
February 24, 2012

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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2011

or

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) of the Securities Exchange Act of 1934

For the transition period from to

Commission File Number 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. þYes oNo

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. oYes þNo

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. þYes oNo

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). þYes oNo

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. o

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). oYes þNo

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, 2011 was approximately $1.6 billion.

The number of shares of the registrant's Common Stock outstanding as of February 16, 2012 was 105,627,721.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement for the Annual Meeting of Shareholders to be held on May 9, 2012, 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, including the potential sale of assets and/or other investments in our subsidiaries and facilities, or any other business plans, forecasts or objectives, any or all of which is subject to change;
- statements regarding our anticipated production volumes, results of exploration, exploitation, development, acquisition or operations expenditures, and current or prospective reserve levels with respect to any oil and gas property or well;
- statements related to commodity prices for oil and gas or with respect to the supply of and demand for oil and gas;
- statements relating to our proposed acquisition, exploration, development and/or production of oil and gas properties, prospects or other interests and any anticipated costs related thereto;
- statements related to environmental risks, exploration and development risks, or drilling and operating risks;
- statements relating to the construction or acquisition of vessels or equipment and any anticipated costs related thereto;
- 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;
- uncertainties inherent in the development and production of oil and gas and in estimating reserves;
- the geographic concentration of our oil and gas operations;
- the effect of regulations on the offshore Gulf of Mexico oil and gas operations;
- uncertainties regarding our ability to replace depletion;
- unexpected future capital expenditures (including the amount and nature thereof);
- impact of oil and gas price fluctuations and the cyclical nature of the oil and gas industry;

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- 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 effectiveness of our hedging activities;
- 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, including the exposure of our oil and gas operations to tropical storm activity in the Gulf of Mexico;
- the impact of operational disruptions affecting the Helix Producer I vessel which is crucial to producing oil and natural gas from our Phoenix field;
- the effect of environmental liabilities that are not covered by an effective indemnity or insurance;
- 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 18 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 field development solutions and other contracting services to the energy market as well as to our own oil and gas properties. We have three reporting business segments: Contracting Services, Production Facilities, and Oil and Gas. Our Contracting Services segment utilizes vessels, offshore equipment and methodologies to deliver services that may reduce finding and development costs and encompass the complete lifecycle of an offshore oil and gas field. These Contracting Services operations are primarily located in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions. Our Production Facilities segment consists of our ownership interest in certain production facilities in hub locations where there is potential for significant subsea tieback activity, our investment in a dynamically positioned floating production vessel (the “Helix Producer I” or “HP I”) and the recently established Helix Fast Action Response System (“HFRS” see “Our Strategy” below). All of our Production Facilities activities are located in the Gulf of Mexico. Our Oil and Gas segment engages in prospect generation, exploration, development and production activities all within in the Gulf of Mexico.

The future focus of the Company is on its Contracting Services businesses, including, well operations, robotics and subsea construction services. For additional information regarding this strategy and about our contracting services operations, see sections titled "Our Strategy," and "Contracting Services Operations" all included elsewhere within Item 1. "Business" of this Annual Report.

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 2011. 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.

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Please refer to the subsection "— Certain Definitions" on page 18 for definitions of additional terms commonly used in this Annual Report. Unless otherwise indicated any reference to Notes herein refers to our Notes to the Consolidated Financial Statements located 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. In July 2006, Helix acquired Remington Oil and Gas Corporation ("Remington"), an exploration, development and production company with operations located primarily in the Gulf of Mexico. 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 (see "Contracting Services Operations – Shelf Contracting" below and Note 3). Prior to the divestiture of CDI, Shelf Contracting Services was our fourth reporting business segment.

OUR STRATEGY

Over the past three years, we have focused on improving our balance sheet by increasing our liquidity through dispositions of non-core business assets, decreasing our planned capital spending and reducing the amount of our debt outstanding. Our focus is to shape the future direction of the Company around the Contracting Services business comprised of our well operations, robotics and subsea construction services. We plan to supplement the expansion of our Contracting Services business with the cash generated by our production facilities business activities and the substantial cash flow associated with our oil and gas business. We can generate cash from our oil and gas operations through a combination of existing and/or future production from our properties and/or the sale of all or a portion of our oil and gas assets.

Since the beginning of 2009, we have generated approximately $600 million in pre-tax proceeds from dispositions of non-core business assets. These transactions included approximately $55 million from the sale of individual oil and gas properties, over $500 million from the sale of our stockholdings in CDI and $25 million for the sale of our former reservoir consulting business.

The primary goal of our Contracting Services business is to provide services and methodologies to the oil and natural gas industry which we believe are critical to developing offshore reservoirs and maximizing the economics from marginal fields. A secondary goal is for our oil and gas operations to generate prospects and to find and develop oil and gas employing our key services and methodologies resulting in a reduction in finding and development costs. Meeting these goals drives our ability to achieve our overall objective of maximizing the value for our shareholders. In order to achieve these goals we will:

Continue Expansion of Contracting Services Capabilities. We will focus on providing offshore services that deliver the highest financial return to us. We are planning to make strategic investments in capital projects that expand our service capabilities or add capacity to existing services in our key operating regions. We recently announced that we are initiating construction of a new multi-service semi-submersible well intervention and well operations vessel similar to our existing Q4000 vessel. This vessel is expected to be completed and placed in service in 2015 at an approximate estimated cost of $525 million. Our most recent completed capital investments include: upgrading the capabilities of our Q4000 vessel, converting a ferry vessel into a dynamically positioned floating production unit vessel (the HP I), and converting a former dynamically positioned cable lay vessel into a deepwater pipelay vessel (the Caesar). We also completed the construction of the Well Enhancer that provides us with greater well intervention servicing capabilities, including installation of a coiled-tubing unit in 2010.

As recent evidence of our commitment to expand our contracting services capabilities we developed the HFRS. The HFRS was developed as a culmination of our experience as a responder in the Gulf oil spill response and containment efforts in 2010. The HFRS centers on two vessels, the HP I and the Q4000, both of which played a key role in Gulf oil spill response and containment efforts and are presently operating in the Gulf of Mexico. In 2011, we signed an agreement with Clean Gulf Associates

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("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 for a two-year term 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 of the CGA participant member companies specifying the day rates to be charged should the HFRS be deployed in connection with a well control incident. The retainer fee for the HFRS became effective April 1, 2011.

Monetize Oil and Gas Reserves and Non-Core Assets. As previously disclosed, we may pursue potential opportunities to sell all or a portion of our oil and gas assets. Until such time as we dispose of our oil and gas assets, we will continue to pursue potential alternatives to sell or reduce our interests in oil and gas reserves once value has been created via prospect generation, discovery and/or development engineering. We may sell interests in oil and gas reserves at any time during the life of the properties.

Focus Exploration Drilling on Select Deepwater Prospects. We are continuing to generate oil and gas prospects and expect to drill in areas we believe are likely to contain largely oil reserves, and where our contracting services assets may be utilized and incremental returns can be achieved through control of and application of our development services and methodologies. We plan to seek partners on these prospects to mitigate risk associated with the cost of drilling and development work.

Continue Exploitation Activities and Converting PUD/PDNP Reserves into Production. Over the years, our oil and gas operations have been able to achieve incremental operating returns and increased operating cash flow due in part to our ability to convert proved undeveloped reserves (“PUD”) and proved developed non-producing reserves (“PDNP”) into producing assets through successful exploitation drilling and well work. As of December 31, 2011, our PUD category represented approximately 16.1 MMBOE or 42% of our total estimated proved reserves. We will focus on cost effectively developing these reserves to generate oil and gas production, or alternatively, selling full or partial interests in them to fund our core Contracting Services business and/or retire outstanding debt.

CONTRACTING SERVICES OPERATIONS

We provide offshore services and methodologies that we believe are critical to developing offshore reservoirs and maximizing production economics. These “life of field” services are represented by four disciplines: (1) well operations, (2) robotics, (3) subsea construction and (4) production facilities. We have disaggregated our contracting service operations into two reportable segments: Contracting Services and Production Facilities. 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 services include:

- 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. In 2011, we 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 windmill foundations.

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

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

- 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 our Phoenix field (Note 5). In addition to the services provided by our HP I vessel, we maintain an equity investment in two production hub facilities in the Gulf of Mexico. We also established the HFRS as a response resource in permit applications to federal and state agencies.

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As of December 31, 2011, our contracting services operations' backlog supported by written agreements or contracts totaled $539.6 million, of which $505.0 million is expected to be performed in 2012. At December 31, 2010, our backlog totaled $267.3 million. 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.

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. However, some of our Contracting Services, generally our subsea construction activities, will often lag drilling operations by a period of 6 to 18 months, meaning that even if there were a sudden increase in deepwater permitting and subsequent drilling in the Gulf of Mexico, it probably would still be some time before we would start securing any awarded projects. The performance of our oil and gas 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.

Although we are still feeling the effects of the recent global recession and are experiencing the consequences of the additional regulatory requirements resulting from the Macondo well explosion and subsequent oil spill in the Gulf of Mexico in 2010, 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 emphasizes the need for continual replenishment of oil and gas production; (2) peaking global production rates; (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. Our strategy of combining contracting services operations and oil and gas operations allows us to focus on trends (4) through (6) in that we pursue long-term sustainable growth by applying specialized subsea services to the broad external offshore market but with a complementary focus on marginal fields and new reservoirs in which we currently have an equity stake.

Well Operations

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 Operations 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 operations to troubleshoot or enhance production, shift sleeves, log wells or perform recompletions. Three of our vessels serve as work platforms for well operations 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 operations "firsts" in increasingly deeper water without the use of a traditional drilling rig. In 2010, the Q4000 served as a key component in the Gulf well control and containment efforts. The Q4000 serves an important role in the HFRS that was established in 2011 (see "Our Strategy" above). In the North Sea, the Seawell has provided intervention and abandonment services for over 700 North Sea subsea wells since 1987. 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 reservoir developments. With the expected long-term increased demand for these services due to the growing number of subsea tree installations, we have the potential for significant backlog for well operations activities and, as a result, we constructed the Well Enhancer and it joined our fleet in October 2009 in the North Sea region.

In February 2012, we announced that we are initiating construction of a new multi-service semi-submersible well intervention and well operations vessel similar to our existing Q4000 vessel. This vessel is expected to be completed and placed in service in 2015 at an approximate estimated cost of $525 million.

The results of Well Operations are reported within our Contracting Services segment (Note 17).

Robotics

We have been actively engaged in Robotics for over 25 years. We operate ROVs, trenchers and ROVDrills designed for offshore construction. As marine construction support in the Gulf of Mexico and other areas of the world moves to deeper waters, use of ROV systems is increasing and the scope of their services is becoming more significant. Our 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 these subsea construction developments in the Gulf of Mexico and internationally. Our 41 ROVs and three trencher systems operate in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions. We currently lease five vessels to support our Robotics services and we have historically engaged additional vessels on short-term (spot) charters as needed. In 2012, we expect to take possession of a new-build vessel, the Grand Canyon, that was commissioned specifically for our use under terms of a long-term charter agreement. The Grand Canyon will initially be deployed to support our new T1200 trencher system.

Over the past few years there has been a dramatic increase in offshore activity associated with the growing alternative energy industry. Specifically there has been a large increase in the amount of services performed on behalf of the wind farm 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 less suitable vessels but these types of services are now contracted to vessels such as our Deep Cygnus chartered vessel and the soon to be commissioned Grand Canyon chartered vessel that are more suitable for harsh weather conditions which can occur offshore, especially in the North Sea region where wind farming is presently concentrated. In 2011, over 15% of our robotics revenues were related to alternative energy contracts. Our robotics division is positioned to continue to increase the services it provides to the alternative energy business. This increase is expected to include the use of our vessels as previously discussed, our trenchers (including the new T-1200 expected to be completed in 2012) that are used to bury the power generation lines and our ROV fleet used in both the installation process as well as ongoing maintenance of such offshore infrastructure.

The results of Robotics are reported within our Contracting Services segment (Note 17).

Subsea Construction

For over 30 years, we have supported offshore oil and natural gas infrastructure projects by providing our construction services. Construction services which we believe are critical to the development of fields in the deepwater include the use of umbilical lay and pipelay vessels and ROVs. We currently own three subsea umbilical lay and pipelay vessels. The Intrepid is a 381-foot DP-2 vessel capable of laying rigid and flexible pipe (up to 8 inches in diameter) and umbilicals. The Express is a 502-foot DP-2 vessel also capable of laying rigid and flexible pipe (up to 14 inches in diameter) and umbilicals. In January 2006, we acquired the Caesar, a mono-hull built in 2002 for the cable lay market. The Caesar is 485 feet long and is equipped with a DP-2 system. The Caesar was placed in service in the Gulf of Mexico in May 2010 following its conversion into a subsea pipelay asset capable of laying rigid pipe up to 30 inches in diameter.

The results of our Subsea Construction operations are reported within our Contracting Services segment (Note 17).

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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. We are positioned to facilitate the tie back of certain of these smaller reservoirs to these hubs through our Contracting Services operations. Ownership of production facilities enables us to earn a transmission company type return through tariff charges while 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 our Phoenix field, which we acquired in 2006 after the hurricanes of 2005 destroyed the TLP which was being used to produce the field. Once production in the Phoenix field ceases to be economic, this re-deployable facility is expected to move to a new location as contracted by a third party, or by our direction to be used to produce other internally-owned reservoirs.

As noted in “Our Strategy” above, we established the HFRS in 2011. The HFRS was contracted to certain members of CGA, a consortium of oil and gas industry participants in the Gulf of Mexico, who have executed a utilization agreement with us. CGA pays us a fixed retainer fee for our vessels, the Q4000 and HP I, both of which are currently operating in the Gulf of Mexico, to be named as well control resources in filed response plans filed with federal and state authorities. This retainer fee is a component of our Production Facilities business segment.

The results of production facilities services are reported as our Production Facilities segment (Note 17).

Shelf Contracting

Our former Shelf Contracting segment represented the operations and results of CDI while CDI was a consolidated, majority-owned subsidiary of Helix. We deconsolidated CDI on June 10, 2009 when our ownership interest in CDI decreased below 50% (Note 3). In 2011, we sold our remaining ownership interest in CDI. Shelf Contracting services provided by CDI included manned diving services, pipelay and pipebury services, platform installation and salvage service. Shelf Contracting also performed saturation, surface and mixed gas diving which enabled us to provide a full complement of manned diving services in water depths of up to 1,000 feet. For the results of our former Shelf Contracting services segment see Note 17.

OIL & GAS OPERATIONS

In 1992, we formed our oil and gas business unit to achieve incremental returns, to expand the utilization of our contracting services assets, and to develop and provide more efficient solutions for offshore abandonment requirements. We have evolved this business model to include not only mature oil and gas properties but also proved and unproved reserves yet to be explored and developed. We have assembled services that allow us to create value at key points in the life of a reservoir from exploration through development, life of field management and operating through abandonment. At December 31, 2011, our estimated proved reserves totaled approximately 38.9 MMBOE, all of which are associated with properties located in the Gulf of Mexico.

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As we previously indicated, under certain circumstances we might consider strategic sales of some or all of our oil and gas properties. As evidence of this strategy, in December 2011 we sold our ownership interest in Green Canyon Block 490 for gross proceeds of approximately $31 million. The transaction is also subject to certain customary closing conditions, which will result in the receipt of additional proceeds for capital expenditures we paid subsequent to the sale transaction effective date. In January 2012, we sold our oil and gas properties within the Main Pass area of the Gulf of Mexico. These seven Main Pass properties were all operated by third parties and the acquirer obtained our ownership interests by assuming our pro rata share of each field's asset retirement obligation. See Note 5 for additional information regarding our recent sale of oil and gas properties. We believe that owning interests in oil and gas reservoirs, particularly in the deepwater, provides the following:

- a potential backlog for our contracting service assets as a hedge against cyclical service asset utilization;
- potential utilization for new non-conventional applications of contracting service assets to hedge against lack of initial market acceptance and utilization risk; and
- incremental returns.

Our oil and gas operations are currently involved in all stages of a reservoir's life. This complete life-cycle involvement allows us to potentially improve the economics of a reservoir that might otherwise be considered non-commercial or non-impact and has identified us as a value adding partner to many producers. Our expertise, along with similarly aligned interests, allows us to develop more efficient relationships with other producers. With a historical focus on acquiring non-impact reservoirs or mature fields, we have been successful in acquiring equity interests in several undeveloped reservoirs in the Deepwater. In the event we continue to own and operate our oil and gas assets, developing these fields over the next few years will require significant capital commitments by us and/or others.

Our oil and gas operations have a prospect inventory, mostly in the Deepwater, which we believe may generate additional life of field services for our Contracting Services vessels. Our Oil and Gas segment has a proven track record of developing prospects into production in the U.S. Gulf of Mexico. We plan to seek partners on these prospects to mitigate risk associated with the costs of drilling and development.

We identify prospective oil and gas properties primarily by using 3-D seismic technology. After acquiring an interest in a prospective property, our strategy is to partner with others to drill one or more exploratory wells. If the exploratory well(s) find commercial oil and/or gas reserves, we complete the well(s) and install the necessary infrastructure to begin producing the oil and/or gas. Because our operations are located in the Gulf of Mexico, we must install facilities such as offshore platforms and gathering pipelines in order to produce the oil and gas and deliver it to the marketplace. Certain properties require additional drilling to fully develop the oil and gas reserves and maximize the production from a particular discovery.

Our oil and gas operations include an experienced team of personnel providing services in geology, geophysics, reservoir engineering, drilling, production engineering, facilities management, lease operations and petroleum land management. We seek to maximize profitability by lowering finding and development costs, lowering development time and cost, operating the field more effectively, and extending the reservoir life through well exploitation operations. When a company sells a property on the Outer Continental Shelf ("OCS"), it retains the financial responsibility for the asset retirement obligations if its purchaser becomes financially unable to do so. Thus, it becomes important that a property be sold to a purchaser that has the financial wherewithal to perform its plug and abandonment obligations. We believe we have a strong reputation among major and independent oil companies. In addition, our reservoir engineering and geophysical expertise, along with our access to contracting service assets that can positively impact development costs, have enabled us to partner with many other oil and gas companies in offshore development projects. We share ownership in our oil and gas properties with various industry participants.

We currently operate the majority of our offshore properties. An operator is generally able to maintain a greater degree of control over the timing and amount of capital expenditures than a non-operating interest owner. See Item 2. Properties "— Summary of Oil and Natural Gas Reserve Data" for detailed disclosures of our oil and gas properties.

The results of our oil and gas operations are reported within our Oil and Gas segment (Note 17).

GEOGRAPHIC AREAS

Revenue by individually significant country is as follows (in thousands):

	Year Ended December 31, 2011	2010	2009
United States	$ 1,013,476	$ 827,597	$ 923,481
United Kingdom	275,499	198,011	124,896
India	44,772	56,311	233,466
Other	64,860	117,919	179,844
Total	$ 1,398,607	$ 1,199,838	$ 1,461,687

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 depreciation, by individually significant country (in thousands):

	Year Ended December 31, 2011	2010	2009
United States	$ 2,034,978	$ 2,236,455	$ 2,564,673
United Kingdom	281,430	275,012	284,637
Other	14,919	15,613	14,396
Total	$ 2,331,327	$ 2,527,080	$ 2,863,706

CUSTOMERS

Our customers include major and independent oil and gas producers and suppliers, pipeline transmission companies and offshore engineering and construction firms. The level of services required by any particular contracting customer depends 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, was as follows: 2011— Shell (49%); 2010 — Shell (29%) and BP Plc (17%) and 2009—Shell (19%). These customers were primarily purchasers of our oil and natural gas production. We estimate that in 2011 we provided subsea services to over 75 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 subsea construction, well operations and production facilities vessels. In addition, our production portfolio inherently provides a backlog of work for our services that we can complete at our option based on market conditions. As of December 31, 2011, our contracting services operations' backlog supported by written agreements or contracts totaled $539.6 million, of which $505.0 million is expected to be performed in 2012. These backlog contracts are cancellable without penalty in many cases. Backlog is not a reliable indicator of total annual revenue for our Contracting Services businesses 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 are also important. Our principal competitors include Oceaneering International, Inc., Saipem, Allseas Group S.A., Subsea 7 S.A., Technip and McDermott International, Inc. Our competitors in the well operations business are the international drilling contractors and specialized contractors.

Our oil and gas operations compete with large integrated oil and gas companies as well as independent exploration and production companies for offshore leases on properties. We also encounter significant competition for the acquisition of mature oil and gas properties. If we continue to own our oil and gas business, our potential ability to acquire additional future properties will depend upon our ability to evaluate and select suitable properties and consummate transactions in a historically highly competitive environment. Many of our competitors may have significantly more financial, personnel, technological, and other resources available to them. In addition, some of the larger integrated companies may be better able to respond to industry changes including price fluctuation, oil and natural gas demand, and governmental regulations. Small or mid-sized producers, and in some cases financial players, with a focus on acquisition of proved developed and undeveloped reserves, are often competition for development properties.

TRAINING, SAFETY AND QUALITY ASSURANCE

We have established a corporate culture in which QHSE remains among the highest of priorities. Our corporate goal, based on the belief that all accidents can be prevented, is to provide an incident-free workplace by focusing on correct and safe behavior. Our QHSE procedures, training programs and management system were developed by management personnel, common industry work practices and by employees with on-site experience who understand the 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 enhance and provide continuous improvements to our behavioral based safety process, as well as our training programs, that continue to focus on safety through open communication. The process includes the documentation of all daily observations, collection of data and data treatment to provide the mechanism of understanding both safe and unsafe behaviors at the worksite. In addition, we initiated scheduled hazard hunts by project management on each vessel, complete with assigned responsibilities and action due dates. Our Contracting Services business has 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 U.S. Customs Service, as well as private industry organizations such as the American Bureau of Shipping (“ABS”). The BOEM and BSEE formally comprised the Bureau of Ocean Energy Management, Regulation and Enforcement (“BOEMRE”) until October 2011. Prior to June 2010 the BOEMRE was known as the Minerals Management Service (“MMS”). 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.

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. Operators on the OCS are currently required to post an area-wide bond of $3.0 million, or $0.5 million per producing lease. We have provided adequate financial assurance for our offshore leases as required by the BOEM.

We acquire production rights to offshore mature oil and gas properties under federal oil and gas leases, which the BOEM and BSEE administers. These leases contain relatively standardized terms and require compliance with detailed BOEM and BSEE regulations and orders pursuant to the Outer Continental Shelf Lands Act (“OCSLA”). These BOEM and BSEE directives are subject to change. The BOEM and BSEE have promulgated regulations requiring offshore production facilities located on the OCS to meet stringent engineering and construction specifications. The BOEM and BSEE also has issued regulations restricting the flaring or venting of natural gas and prohibiting the burning of liquid hydrocarbons without prior authorization. Similarly, the BOEM and BSEE have promulgated other regulations governing the plugging and abandonment of wells located offshore and the removal of all production facilities. Finally, under certain circumstances, the BOEM and BSEE may require any operations on federal leases to be suspended or terminated or may expel unsafe operators from existing OCS platforms and bar them from obtaining future leases. Suspension or termination of our operations or expulsion from operating on our leases and obtaining future leases could have a material adverse effect on our financial condition and results of operations.

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 on October 12, 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), 2010-N05 (Safety NTL), NTL 2010-N06 (Environmental NTL) and the Interim Final Rule (Drilling Safety Rule), and NTL 2010-N10 (Compliance and Evaluation NTL). Inspections will be conducted of each deepwater drilling operation for compliance with BOEM and BSEE regulations, including but not limited to the testing of blow out 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.

Under the OCSLA and the Federal Oil and Gas Royalty Management Act, the ONRR establishes regulations that set the basis for royalties on oil and gas. The regulations address the proper way to value production for royalty purposes, including the deductibility of certain post-production costs from that value. Separate sets of regulations govern natural gas and oil and are subject to periodic revision by the ONRR.

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 (“NGPA”), and the regulations promulgated thereunder by the Federal Energy Regulatory Commission (“FERC”). In the past, the federal government has regulated the prices at which oil and gas could be sold. Deregulation of wellhead sales in the natural gas industry began with the enactment of the NGPA. In 1989, the

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Natural Gas Wellhead Decontrol Act was enacted, removing both price and non-price controls from natural gas sold in "first sales" no later than January 1, 1993. While sales by producers of natural gas, and all sales of crude oil, condensate and natural gas liquids currently can be made at uncontrolled market prices, Congress could reenact price controls in the future.

Sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation remain subject to extensive federal and state regulation. Several major regulatory changes have been implemented by Congress and FERC since 1985 that affect the economics of natural gas production, transportation and sales. In addition, as a result of the Energy Policy Act of 2005, FERC continues to promulgate revisions to various aspects of the rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies, that remain subject to FERC jurisdiction. In addition, however, changes in FERC rules and regulations may also affect the intrastate transportation of natural gas, as well as the sale of natural gas in interstate and intrastate commerce, under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry, and to prevent fraud and manipulation of interstate transportation markets. We cannot predict what further action FERC will take on these matters, but we do not believe any such action will materially adversely affect us differently from other companies with which we compete.

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. In the past, the natural gas industry has been heavily regulated. There is no assurance that the regulatory approach currently pursued by FERC will continue indefinitely.

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 $350 million for onshore facilities, all removal costs plus $75 million for offshore facilities, and the greater 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.

OPA also imposes ongoing requirements on a Responsible Party, including preparation of an oil spill contingency plan and maintaining proof of financial responsibility to cover a majority of the costs in a potential spill. We believe that we have appropriate spill contingency plans in place. With respect to financial responsibility, OPA requires the Responsible Party for certain offshore facilities to demonstrate financial responsibility of not less than $35 million, with the financial responsibility requirement potentially increasing up to $150 million if the risk posed by the quantity or quality of oil that is explored for or produced indicates that a greater amount is required. The BOEM has promulgated regulations implementing these financial responsibility requirements for covered offshore facilities. Under the BOEM regulations, the amount of financial responsibility required for an offshore facility is increased above the minimum amounts if the “worst case” oil spill volume calculated for the facility exceeds certain limits established in the regulations. We believe that we currently have established adequate proof of financial responsibility for our onshore and offshore facilities and that we satisfy the BOEM requirements for financial responsibility under OPA and applicable regulations.

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 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, on October 30, 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, with reporting beginning in 2012 for emissions in 2011.

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.

INSURANCE MATTERS

The well operations, robotics and subsea construction activities 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 flow.

Similarly, our oil and gas operations are subject to risks incident to the operation of oil and gas wells, including but not limited to uncontrolled flows of oil, gas, brine or well fluids into the environment, blowouts, cratering, mechanical difficulties, fires, explosions or other physical damage, pollution or other risks, any of which could result in substantial losses to us. Although we maintain insurance against some of these risks we cannot insure against all possible losses. As a result, any damage or loss not covered by our insurance could have a material adverse effect on our financial condition, results of operations and cash flow.

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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 1152ber 72005 Plan - Lovoi-12-0 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 Intrepid, Seawell and Express, and $375,000 on the Caesar. In addition to the primary deductibles, the vessels are subject to an annual aggregate deductible of $1.75 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 also maintain 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 have not insured for windstorm damage under traditional insurance policies for the past three years because premium and deductibles would be relatively substantial for the coverage provided. In order to mitigate potential loss with respect to our most significant oil and gas properties from hurricanes in the Gulf of Mexico, we purchased Catastrophic Bond instruments covering each of the last three insurance years, with the most recent instrument covering the period from July 1, 2011 through June 30, 2012. Our current Catastrophic Bond provides for payments of negotiated amounts should the eye of a Category 2 or Category 3 or greater hurricane pass within specific pre-defined areas encompassing our more significant oil and gas producing fields.

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, 2011, we had 1,655 employees, approximately 675 of which were salaried personnel. As of December 31, 2011, we also contracted with third parties to utilize 140 non-U.S. citizens to crew our foreign flagged vessels. Except for a very limited number of our workshop employees in Australia, 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, 2011, 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 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.

BOEMRE: Until October 1, 2011, the Bureau of Ocean Energy Management, Regulation and Enforcement, an agency of the Department of Interior, had responsibility for all aspects of offshore federal leasing, including for overseeing the development of energy and mineral resources on the Outer Continental Shelf of the Gulf of Mexico. The multi-departmental BOEMRE was the successor to the Mineral Management Service ("MMS"), which until June 2010 was the federal regulatory body overseeing the development of mineral resources in the United States. Effective October 1, 2011, the BOEMRE was separated into two separate federal agencies, the Bureau of Ocean Energy Management ("BOEM") and the Bureau of Safety and Environmental Management ("BSEE").

BOEM: As noted above, the BOEM is one of two successor federal agencies to BOEMRE. The 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 BSEE is the second of the two successor federal agencies to BOEMRE. The 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

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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.

E&P: Oil and gas exploration and production activities.

F&D: Total cost of finding and developing oil and gas reserves.

G&G: Geological and geophysical.

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.

Peer Group-Contracting Services: For purposes of this Annual Report on Form 10-K, FMC Technologies, Inc. (NYSE: FTI), Atwood Oceanics, Inc. (NYSE: ATW), McDermott International, Inc. (NYSE: MDR), Oceaneering International, Inc. (NYSE: OII), Cameron International Corporation (NYSE: CAM), Oil States International, Inc. (NYSE: OIS), Rowan Companies, Inc. (NYSE: RDC), Superior Energy Services, Inc (NYSE: SPN), Tetra Technologies, Inc. (NYSE: TTI), Petrofac (LSE:PFC.L) and Dril-Quip, Inc. (NYSE:DRQ).

Peer Group-Oil and Gas: For purposes of this Annual Report, ATP Oil & Gas Corporation (NASDAQ: ATPG), W&T Offshore, Inc. (NYSE: WTI), Energy XXI (Bermuda) Limited (NYSE: EXXI), and Stone Energy Corporation (NYSE: SGY).

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.

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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.

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 Operations 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.

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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.

Risks Relating to General Corporate Matters

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:

- 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 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;
- consolidation by our customers, which could result in loss of a customer; and
- 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.

The Deepwater Horizon drilling rig explosion in the Gulf of Mexico, the subsequent oil spill and the resulting enhanced regulations for deepwater drilling offshore the United States may impact our oil and gas business located offshore in the Gulf of Mexico and reduce the need for our services in the Gulf of Mexico.

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 on October 12, 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), 2010-N05 (Safety NTL), NTL 2010-N06 (Environmental NTL) and the Interim Final Rule (Drilling Safety Rule), and NTL 210-N10 (Compliance and Evaluation NTL). BSEE also plans to conduct inspections of each deepwater drilling operation for compliance with BSEE's regulations, including but not limited to the testing of blow out 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 has established a mechanism relating to the availability of blowout containment resources, including our HFRS 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. 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

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oil and gas wells. In addition, growth in our oil and gas business and any potential disposition of that business will be affected by the ability to develop our portfolio of prospects. We can provide no assurance regarding the timing of future drilling permits. With respect to our services business, if the issuance of permits is significantly delayed, and 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 following the Deepwater Horizon rig explosion, and potentially in other areas around the world, may impact our oil and gas business and reduce the need for our services in those areas.

The Deepwater Horizon rig explosion in the Gulf of Mexico and its aftermath has resulted in new regulations in the United States, which may result in substantial increases in costs or delays in drilling or other operations in the Gulf of Mexico, oil and gas projects becoming potentially non-economic, and a corresponding reduced demand for our services. 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. In addition, safety requirements or other governmental regulations could increase our costs of operation of our oil and gas business and impact our ability to divest the assets of that business. Likewise this could also result in increased costs of operating our contracting services business, and our potential consumers' oil and gas projects becoming non-economic, which could also negatively affect the demand for our contracting services business. If the United States or other countries where we operate enact stricter restrictions on offshore drilling or further regulate offshore drilling or contracting services operations, our business, financial condition and results of operations could be materially affected.

Government Regulation, including recent legislative initiatives, may affect demand for our services.

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. In addition, because we hold federal leases, the federal government requires us to comply with numerous additional regulations that focus on government contractors. 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,

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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, on October 30, 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 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, with reporting beginning in 2012 for emissions in 2011.

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 products and 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.

In 2009, U.S. Customs and Border Protection ("CBP") issued a proposed modification to its prior rulings regarding the application of the Jones Act to the carriage by foreign flag vessels of items relating to certain offshore activities on the OCS. CBP withdrew the proposed modifications later that year. 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 implemented the same modifications as the CBP 2009 proposal. 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, this 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 pipelay or well operation services.

Beginning in 2011, the federal government has proposed to levy a tax on offshore production and to repeal a number of existing tax preferences for domestic oil and gas producers. The tax preferences include, but are not limited to, the elimination of the immediate expensing of intangible drilling costs, the use of percentage depletion methodology in respect to oil and gas wells, the ability to claim the domestic manufacturing deduction against income derived from oil and gas production and other preference items. The elimination of one or all of these tax preferences may have an adverse impact on our financial results in future years. In addition, it is uncertain as to whether we will be able to recoup these additional tax costs from our customers.

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 United States economy and the worldwide economy may require some time to recover from the recent global recession. 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

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may also adversely affect our revenues from our oil and gas business and indirectly, our service business. The extent of the impact of these factors on our results of operations and cash flow 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.

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 as witnessed in 2008 and 2009 and the developing 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.

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.

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 the Company's 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

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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.

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

As of December 31, 2011, we had approximately $1.2 billion of consolidated indebtedness outstanding. The significant 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 flow 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 flow 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, such as was experienced in late 2008 and in 2009, 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.

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

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The Company's 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 the Company's consolidated financial statements is the U.S. dollar. Certain of the Company's assets, liabilities, expenses and revenues are denominated in other countries' currencies. Those assets, liabilities, expenses and revenues are translated into U.S. dollars at the applicable exchange rates to prepare the Company's 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 the Company's 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 the Company's results.

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

The businesses 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 the exploration and production business, some of the larger integrated companies may be better able to respond to industry changes including price fluctuations, oil and gas demand, political change and government regulations.

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 products and services require 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, our results of operations could be harmed.

We have a history of growing through acquisitions of large assets and acquisitions of companies. We must plan and manage our acquisitions effectively to achieve revenue growth and maintain profitability in our evolving market. If we fail to effectively manage current and future acquisitions, our results of operations could be adversely affected. 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 growth of our business.

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

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.

Risks Relating to our Contracting Services Operations

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:

- 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.

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 construction activity expands into deeper water in the Gulf of Mexico and other deepwater basins of the world, a greater percentage of our revenues will be from deepwater construction projects that are larger and more complex, and thus riskier, than shallow water projects. 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 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 typically 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, including our vessels and structures on our offshore oil and gas properties, 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 both service and production 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.

If we bid too low on a turnkey contract, we suffer adverse economic consequences.

A significant amount of our projects are performed on a qualified turnkey basis where described work is delivered for a fixed price and extra work, which is subject to customer approval, is billed separately. The revenue, cost and gross profit realized on a turnkey contract can vary from the estimated amount because of changes in offshore job conditions, variations in labor and equipment productivity from the original estimates, the performance of third parties such as equipment suppliers, or other factors. These variations and risks inherent in the marine construction industry may result in our experiencing reduced profitability or losses on projects.

Risks Relating to our Oil and Gas Operations

Exploration and production of oil and natural gas is a high-risk activity and is subject to a variety of factors that we cannot control.

Our oil and gas business is subject to all of the risks and uncertainties normally associated with the exploration for and development and production of oil and natural gas, including uncertainties as to the presence, size and recoverability of hydrocarbons. We may not encounter commercially productive oil and natural gas reservoirs. We may not recover all or any portion of our investment in new wells. The presence of unanticipated pressures or irregularities in formations, miscalculations or accidents may cause our drilling activities to be unsuccessful and/or result in a total loss of our investment, which could have a material adverse effect on our financial condition, results of operations and cash flows. In addition, we often are uncertain as to the future cost or timing of drilling, completing and operating wells.

Projecting future natural gas and oil production is imprecise. Producing oil and gas reservoirs eventually have declining production rates. Projections of production rates rely on certain assumptions regarding historical production patterns in the area or formation tests for a particular producing horizon. Actual production rates could differ materially from such projections. Production rates also can depend on a number of additional factors, including commodity prices, market demand and the political, economic and regulatory climate.

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Our business is subject to all of the operating risks associated with drilling for and producing oil and natural gas, including:

- fires;
- title problems;
- explosions;
- pressures and irregularities in formations;
- equipment availability;
- blow-outs and surface cratering;
- uncontrollable flows of underground natural gas, oil and formation water;
- natural events and natural disasters, such as loop currents, hurricanes and other adverse weather conditions;
- pipe or cement failures;
- casing collapses;
- lost or damaged oilfield drilling and service tools;
- abnormally pressured formations; and
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases.

If any of these events occurs, we could incur substantial losses as a result of injury or loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties, suspension of our operations and repairs to resume operations.

Natural gas and oil prices are volatile, which makes future revenue uncertain.

Our financial condition, cash flow and results of operations depend in part on the prices we receive for the oil and gas we produce. The market prices for oil and gas are subject to fluctuation in response to events beyond our control, such as:

- supply of and demand for oil and gas;
- market uncertainty;
- worldwide political and economic instability; and
- government regulations.

Oil and gas prices have historically been volatile, and such volatility is likely to continue. Our ability to estimate the value of producing properties for acquisition or disposition, and to budget and project the financial returns of exploration and development projects is made more difficult by this volatility. In addition, to the extent we do not forward sell or enter into costless collars or swap financial contracts in order to hedge our exposure to price volatility, a dramatic decline in such prices could have a substantial and material effect on:

- our revenues;
- results of operations;
- cashflow;
- financial condition;
- our ability to increase production and grow reserves in an economically efficient manner; and
- our access to capital.

Our commodity price risk management related to some of our oil and gas production may reduce our potential gains from increases in oil and gas prices.

Oil and gas prices can fluctuate significantly and have a direct impact on our revenues. To manage our exposure to the risks inherent in such a volatile market, from time to time we have entered into contracts to financially hedge the future cash flow associated with our production. This means that a portion of our production is sold at a fixed price or within a fixed price range as a shield against dramatic price declines that could occur in the market. We have hedged a significant portion of our anticipated production for both 2012 and 2013 with such financial hedging contracts. We may from time to time

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engage in other hedging activities including the forward sale of future production. These hedging activities may limit our benefit from commodity price increases.

We are vulnerable to risks associated with the Gulf of Mexico because our oil and gas operations are located exclusively in that area and our proved reserves are concentrated in a limited number of fields.

Our concentration of oil and gas properties in the Gulf of Mexico makes us more vulnerable to the risks associated with operating in that area than our competitors with more geographically diverse operations. These risks include:

- tropical storms and hurricanes, which are common in the Gulf of Mexico during certain times of the year;
- extensive governmental regulation (including regulations that may, in certain circumstances, impose strict liability for pollution damage); and
- interruption or termination of operations by governmental authorities based on environmental, safety or other considerations.

Any event affecting this area in which we operate our oil and gas properties may have an adverse effect on our financial position, results of operations and cash flow. We also may incur substantial liabilities to third parties or governmental entities, which could have a material adverse effect on our financial condition, results of operations and cash flow.

All of our estimated proved reserves are located in the Gulf of Mexico and we have two fields, Bushwood located at Garden Banks Blocks 462, 463, 506 and 507 and Phoenix located at Green Canyon Blocks 236, 237, 238 and 282, that represents approximately 16% and 23%, respectively, of our total estimated proved reserves as of December 31, 2011. If the proved reserves at these fields are affected by any combination of adverse factors our future estimates of proved reserves could be decreased, perhaps significantly, which may have an adverse effect on our future results of operations and cash flows. Production from the Phoenix field totaled approximately 11,250 barrels per day in 2011 or 47% of our average daily production level. If an adverse event were to occur to our wells or the HP I, which serves as the processing unit for the field’s production, our results of operations and cash flows would be adversely affected.

Estimates of crude oil and natural gas reserves depend on many factors and assumptions, including various assumptions that are based on conditions in existence as of the dates of the estimates. Any material change in those conditions, or other factors affecting those assumptions, could impair the quantity and value of our crude oil and natural gas reserves.

This Annual Report contains estimates of our proved oil and natural gas reserves and the estimated future net cash flows therefrom based upon reports for the years ended December 31, 2011 and 2010, prepared by independent petroleum engineers. These reports rely upon 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 data for each reservoir. As a result, these estimates are inherently imprecise. Actual future production, cash flows, development and production expenditures, operating expenses and asset retirement costs and quantities of recoverable oil and gas reserves may vary from those estimated in these reports. Any significant variance in these assumptions could materially affect the estimated quantity and value of our proved reserves. You should not assume that the present value of future net cash flows from our proved reserves referred to in this Annual Report is the current market value of our estimated oil and gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the average of oil and gas prices on the first day of the month for the past twelve months and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the net present value estimate. In addition, if costs of abandonment are materially greater than our estimates, they could have an adverse effect on financial position, cash flows and results of operations.

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Approximately 68% of our total estimated proved reserves are either PDNP, PDSI or PUD and those reserves may not ultimately be produced or developed.

As of December 31, 2011, approximately 18% of our total estimated proved reserves were PDNP, 9% were PDSI and approximately 42% were PUD. These reserves may not ultimately be developed or produced. Furthermore, not all of our PUD or PDNP may be ultimately produced during the time periods we have planned, at the costs we have budgeted, or at all, which in turn may have a material adverse effect on our results of operations and cash flow.

Reserve replacement may not offset depletion.

Oil and gas properties are depleting assets. We replace reserves through acquisitions, exploration and exploitation of current properties. Approximately 68% of our proved reserves at December 31, 2011 are PUD, PDSI and PDNP. Further, our proved producing reserves at December 31, 2011 are expected to experience annual decline rates ranging from 30% to 40% over the next ten years. If we are unable to acquire additional properties or if we are unable to find additional reserves through exploration or exploitation of our properties, our future cash flows from oil and gas operations could decrease.

We are, in part, dependent on third parties with respect to the transportation of our oil and gas production and in certain cases, third party operators who influence our productivity.

Notwithstanding our ability to produce hydrocarbons, we are dependent on third party transporters to bring our oil and gas production to the market. In the event a third party transporter experiences operational difficulties, due to force majeure including weather damage, pipeline shut-ins, or otherwise, this can directly influence our ability to sell commodities that we are able to produce. In addition, with respect to oil and gas projects that we do not operate, we have limited influence over operations, including limited control over the maintenance of safety and environmental standards. The operators of those properties may, depending on the terms of the applicable joint operating agreement:

- refuse to initiate exploration or development projects;
- initiate exploration or development projects on a slower or faster schedule than we would prefer;
- delay the pace of exploratory drilling or development; and/or
- drill more wells or build more facilities on a project than we can afford, whether on a cash basis or through financing, which may limit our participation in those projects or limit the percentage of our revenues from those projects.

The occurrence of any of the foregoing events could have a material adverse effect on our anticipated exploration and development activities.

Our oil and gas operations involve significant risks, and we do not have insurance coverage for all risks.

Our oil and gas operations are subject to risks incident to the operation of oil and gas wells, including, but not limited to, uncontrollable flows of oil, gas, brine or well fluids into the environment, blowouts, cratering, mechanical difficulties, fires, explosions or other physical damage, pollution and other risks, any of which could result in substantial losses to us. We maintain insurance against some, but not all, of the risks described above. As a result, any damage not covered by our insurance could have a material adverse effect on our financial condition, results of operations and cash flow.

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.

Since the beginning of 2009, dispositions of non-core business assets (see “Our Strategy” above) resulted in receipt of the following pre-tax proceeds:

- Approximately $55 million from the sale of individual oil and gas properties;
- $100 million from the sale of a total of 15.2 million shares of CDI common stock held by us to CDI in separate transactions in January and June 2009;
- Approximately $404.4 million, net of underwriting fees, from the sale of a total of 45.8 million shares of CDI common stock held by us to third parties in separate public secondary offerings one each in June 2009 and September 2009 (for additional information regarding the sales of CDI common shares by us see Note 3); and
- $25 million for the sale of our subsurface reservoir consulting business in April 2009.

OUR VESSELS

We own a fleet of seven vessels and 40 ROVs, three trenchers, and two ROV Drills. We also lease five 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
Intrepid (3)	Bahamas	8/1997	381	89	Capable	DP	400
Floating Production Unit —							
Helix Producer I (4)	Bahamas	4/2009	528	95	—	DP	26 and 26

Well Operations —							
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
Normand Clough (6)	Norway	11/2008	385	120	Capable	DP	250
Robotics —							
41 ROVs, 3 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
Island Pioneer (8)	Vanuatu	5/2008	312	110	—	DP	140
Deep Cygnus (8)	Panama	4/2010	400	92	—	DP	150 and 25
Stril Explorer (8)	Isle of Man	10/2011	251	70	—	DP	60 and 10

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(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 9.

(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 9).

(5) Subject to vessel mortgage securing our MARAD debt described in Note 9.

(6) Chartered by our Australian joint venture, in we which maintain a 50% ownership interest – Note 7

(7) Average age of our fleet of ROVs, trenchers and ROV Drills is approximately 5.2 years.

(8) Leased. One ROV is leased, we own the remaining 40 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, 2011, 2010 and 2009:

	Year Ended December 31,		
	2011	2010	2009
Contracting Services:			
Pipelay and robotics support	76%	84%	79%
Well operations	90%	83%	82%
ROVs	60%	62%	68%

We incur routine drydock, 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. 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. First production began in July 2007. The Independence Hub facility is capable of processing up to one Bcf per day of gas.

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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.

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 our Phoenix field; however, in June 2010 as we approached reestablishment of production from the Phoenix field, the vessel was contracted to assist in the Gulf oil spill response and containment efforts (Note 1). Following these services, the HP I returned to the Phoenix field, where production commenced in October 2010. The results of Kommandor LLC and the HP I are consolidated within our Production Facilities business segment (Note 17).

SUMMARY OF OIL AND NATURAL GAS RESERVE DATA

Accounting Rules Activities

We adopted the oil and gas modernization disclosure rules on December 31, 2009 in conjunction with our year-end 2009 proved reserve estimates. The most significant effect the adoption of these rules has had on our estimated reserve process is the use of the average oil and gas price for the year and the impact of the rules requiring development of proved undeveloped reserves within five years, which affected us in both 2011 and 2010 and could significantly impact future estimates of our proved reserves (see “Proved Undeveloped Reserves” below).

Internal Controls Over Reserve Estimation Process

Our policies regarding internal controls over the recording of reserve estimates require reserves to be in compliance with the SEC definitions and guidance and prepared in accordance with generally accepted petroleum engineering principles. Responsibility for compliance in reserves bookings is delegated to our Manager—Planning and Reserve Evaluation.

Our Manager—Planning and Reserve Evaluation prepares all reserve estimates covering all of our oil and gas properties. Our Manager—Planning and Reserve Evaluation is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Our Manager—Planning and Reserve Evaluation attended Texas A&M University for his undergraduate and graduate studies in Petroleum Engineering and has over 11 years of industry experience with positions of increasing responsibility in engineering and reservoir evaluations.

We employ full-time experienced reserve engineers and geologists who are responsible 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. Our internal reservoir engineers analyzed 100% of our oil and gas fields on an annual basis (65 fields as of December 31, 2011).

Lastly, we engage a third party independent reservoir engineer firm to separately review our reserve estimation process and the results of this process. We also separately engaged the independent reservoir engineer firm to prepare their own estimates of our proved reserves during each of the years ended December 31, 2011, 2010 and 2009. Their report for the proved reserve estimates at December 31, 2011 is included herein as Exhibit 99.1 to this Annual Report.

The table below sets forth the approximate estimate of our proved reserves as of December 31, 2011. Proved reserves cannot be measured exactly because the estimation of reserves involves numerous judgmental determinations. 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.

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	As of December 31, 2011		
	Proved Developed Reserves	Proved Undeveloped Reserves	Total Proved Reserves
Gas (Bcf)	59,859	37,162	97,021
Oil (MBbls)	12,754	9,935	22,689
Total (MBOE)	22,731	16,129	38,860

Proved Undeveloped Reserves (“PUDs”)

At December 31, 2011, our PUDs totaled 37.2 Bcf of natural gas and 9.9 MMBbls of crude oil for a total of 16.1 MMBOE. Our PUDs represent approximately 42% of our total estimates of proved oil and natural gas reserves at December 31, 2011. At December 31, 2010 our estimated PUD reserves totaled 38.3 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.

At December 31, 2011, our most substantial PUDs are located at our East Cameron Block 346 and Bushwood fields (see “Significant Oil and Gas Properties” below). The East Cameron Block 346 field has estimated PUD reserves of approximately 4.3 MMBOE, which represents approximately 26% of our total PUD reserves and approximately 11% of our total estimated proved reserves. Our Bushwood field has estimated PUDs totaling approximately 3.1 MMBOE, which represents approximately 19% of all our estimated PUD reserves and 8% of our total estimated proved reserves. 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, $40.1 million in 2010 and $53.2 million in 2009. All PUD drilling locations are expected to be drilled pursuant with the newly enacted requirements (see “Accounting Rules Activity” above). Accordingly, estimated future development costs related to the development of PUDs are approximately $336.2 million at December 31, 2011.

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 19.

Significant Oil and Gas Properties

Our oil and gas properties consist of interests in developed and undeveloped oil and gas leases. As of December 31, 2011, our exploration, development and production operations were located exclusively in the United States and located offshore in the Gulf of Mexico. We have one inactive field, known as Camelot, located in the North Sea. We plan to substantially complete the abandonment of the Camelot field during 2012 in accordance with applicable United Kingdom regulations.

All of our production during 2011 and the 38.9 MMBOE of total estimated proved reserves at December 31, 2011 (approximately 68% of such total estimated reserves are PUDs, PDSI, and PDNP) is attributed to our properties located in the U.S. Gulf of Mexico. The following table provides a brief description of our oil and gas properties we consider most significant to us at December 31, 2011:

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	Development Location	Net Total Proved Reserves (MMBOE)	Net Proved Reserves Mix Oil %	Gas %	2011 Net Production (MMBOE)	Average WI%	Expected First Production
Deepwater							
Bushwood(1)	U.S. GOM	6.2	9	91	1.3	51	Producing
Phoenix(2)	U.S. GOM	8.8	77	23	4.1	70	Producing
Gunnison(3)	U.S. GOM	2.3	81	19	0.3	19	Producing
Outer Continental Shelf							
East Cameron 346	U.S. GOM	5.2	81	19	0.1	75	Producing
South Timbalier 86/63	U.S. GOM	3.7	45	55	0.4	91	Producing
South Pass 89	U.S. GOM	1.2	30	70	0.1	27	Producing
High Island A557	U.S. GOM	2.9	70	30	0.3	100	Producing
South Marsh Island 130	U.S. GOM	2.4	81	19	0.5	100	Producing
Ship Shoal 223/224	U.S. GOM	1.0	29	71	0.3	51	Producing
Eugene Island 302	U.S. GOM	1.2	82	18	-	100	PDSI 2012

(1) Garden Banks Blocks 462, 463, 506 and 507. Although the Bushwood field is currently producing, there remains a significant amount of PUD reserves that we intend to develop in order to sustain future production from the field.

(2) Green Canyon Blocks 236, 237, 238 and 282.

(3) Third party operated property comprised of Garden Banks Blocks 625, 667, 668 and 669.

United States Offshore

Deepwater

The proved reserves estimates associated with our three fields in the Deepwater of the Gulf of Mexico totaled approximately 17.3 MMBOE or approximately 44% of our total estimated proved reserves at December 31, 2011. We operate both the Phoenix field and certain portions of the Bushwood field, representing approximately 87% 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 Jake field at Green Canyon Block 490 for gross proceeds of approximately $31 million. The Jake field was substantially developed during 2011. Our net production from our Deepwater properties totaled approximately 5.7 MMBOE in 2011 as compared to 4.5 MMBOE in 2010. The increased production reflects the commencement of production from the Phoenix field in October 2010, and was partially offset by decreasing production from both the Bushwood and Gunnison fields.

Outer Continental Shelf

The estimated proved reserves for our 62 fields in the Gulf of Mexico on the OCS totaled approximately 21.6 MMBOE, or 56% of our total estimated proved reserves, as of December 31, 2011. Our net production from the OCS properties totaled approximately 3.0 MMBOE in 2011 and 3.4 MMBOE in 2010. Our largest field on the OCS is East Cameron Block 346, the total estimated proved reserves of which represents approximately 24% of our aggregated OCS estimated proved reserves (or approximately 13% of total estimated proved reserves). Only three other individual OCS fields represented over 5% of our total estimated proved reserves at December 31, 2011. The South Timbalier Blocks 86/63 field represented approximately 17% of our total estimated OCS proved reserves (or approximately 10% of our total estimated proved reserves), the High Island Block 557 field represented approximately 14% of our total estimated OCS proved reserves (or approximately 7.5% of our total estimated proved reserves) and the South Marsh Island Block 130 field represented approximately 11% of total OCS proved reserves (approximately 6% of total estimated proved reserves). We are the operator of 89% of our OCS properties the aggregate estimated proved reserves of which totals approximately 19.2 MMBOE .

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As long as we continue to have interests in our oil and gas properties, we will continue to advance our development activities and may pursue additional future exploration opportunities primarily in the Deepwater of the Gulf of Mexico.

United Kingdom Offshore

In December 2006, we acquired the Camelot field, located 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 5). We are now obligated to pay the entire asset retirement obligation for the field (estimated to approximate $27.3 million at December 31, 2011). During 2011, we commenced abandonment of the Camelot field in accordance with the then applicable U.K. regulations. We plan to substantially complete these abandonment activities in 2012. In 2011, we recorded impairment charges totaling approximately $20 million to increase the estimated asset retirement obligation associated with this field following changes in certain U.K. regulations (Note 5). Excluding these impairment charges, the results of our U.K. operations were immaterial for each of the three years ended December 31, 2011, 2010 and 2009, respectively.

Production, Price and Cost Data

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

	Year Ended December 31,		
	2011	2010	2009
Production:			
Gas (Bcf)	17	27	27
Oil (MMBbls)	6	3	3
Total (MBOE)	8,694	7,870	7,297
Average sales prices realized (including hedges):			
Gas (per Mcf)(1)	$ 6.04	$ 6.01	$ 4.48
Oil (per Bbl)	$ 100.91	$ 75.27	$ 67.11
Total (BOE)	$ 79.26	$ 52.78	$ 41.98
Average production cost per BOE	$ 20.73	$ 17.24	$ 16.42
Average depletion and amortization per BOE	$ 25.29	$ 29.89	$ 23.20

(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, 2011 is as follows:

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
United States – Offshore	231	182	232	123	463	305

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.

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The following table summarizes non-producing wells and wells with multiple completions as of December 31, 2011:

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Not producing (shut-in)	77	56	128	67	205	123
Multiple completions	15	7	42	18	57	25

Developed and Undeveloped Acreage

The developed and undeveloped acreage (including both leases and concessions) that we held at December 31, 2011 is as follows:

	Undeveloped		Developed	
	Gross	Net	Gross	Net
United States – Offshore	135,628	117,500	316,986	184,885

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
2012	26,515	18,755
2013	30,760	30,760
2014	5,760	5,760
2015	5,760	5,760
2016	40,320	33,408
2017 and beyond	26,513	23,057
Total	135,628	117,500

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, 2011, 2010 and 2009:

	Net Exploratory Wells	Net Development Wells

	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2011	—	—	—	—	—	—
Year ended December 31, 2010	—	—	—	1.0	—	1.0
Year ended December 31, 2009	0.3	—	0.3	—	—	—

No wells were drilled in the United Kingdom in 2011, 2010 or 2009. We did not have any wells in progress at December 31, 2011.

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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.

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 5, for additional information regarding our oil and gas operations.

FACILITIES

Our corporate headquarters are located at 400 North Sam Houston Parkway, East, Suite 400, Houston, Texas. We own the Aberdeen (Dyce), Scotland facility and our Spoolbase in Ingleside, Texas. All other facilities are leased.

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	

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Location	Function	Size
Perth, Australia	Helix Well Ops SEA Pty Ltd Well Ops SEA Pty Ltd Helix Energy Services Pty Limited Corporate Offices	2.3 acres (Buildings: 36,706 square feet)
Singapore	Canyon Offshore International Corp Corporate, Operations and Sales Helix Offshore Crewing Service Pte. Ltd. Corporate Headquarters	22,486 square feet

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 has 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.

We have received value added tax (VAT) assessments from the State of Andhra Pradesh, India (the "State") in the amount of approximately $28 million related to our subsea and diving contract in India entered into in December 2006 for the tax years 2007, 2008, 2009, and 2010. 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 would have a material negative effect on our consolidated results of operations while also impacting our financial position.

Item 4. Removed and Reserved.

Executive Officers of the Company

The executive officers of Helix are as follows:

Name	Age	Position
Owen Kratz	57	President and Chief Executive Officer and Director
Anthony Tripodo	59	Executive Vice President and Chief Financial Officer

Alisa B. Johnson	54	Executive Vice President, General Counsel and Corporate Secretary
Johnny Edwards	58	Executive Vice President — Oil & Gas
Clifford V. Chamblee	52	Executive Vice President — Contracting Services
Lloyd A. Hajdik	46	Senior Vice President — Finance and Chief Accounting Officer

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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 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).

Johnny Edwards is Executive Vice President — Oil & Gas of Helix. He was named Executive Vice President — Oil & Gas in March 2010. Mr. Edwards joined the Company in its oil and gas subsidiary, Energy Resources Technology GOM, Inc. (ERT), in 1994. Mr. Edwards served as President of ERT since 2000. Prior to becoming President of ERT, Mr. Edwards held several positions with increasing responsibilities at ERT managing the engineering and acquisitions for the company. Mr. Edwards has been involved in the oil and gas industry for over 35 years. Prior to joining ERT, Mr. Edwards spent 19 years in a broad range of engineering, operations and management positions with ARCO Oil & Gas Co. Mr. Edwards has a Bachelor of Science degree in chemical engineering from Louisiana Tech University.

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, supply chain and corporate planning functions as well as oversight to ERT. 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 2002 to 2003, Mr. Tripodo was Executive Vice President of Veritas DGC, Inc., an international oilfield service company specializing in geophysical services. Prior to becoming Executive Vice President, he was President of Veritas DGC's North and South American Group. From 1997 to 2001, he was Executive Vice President, Chief Financial Officer and Treasurer of Veritas. 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 graduated Summa Cum Laude with a Bachelor of Arts degree from St. Thomas University (Miami).

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 has been involved with the energy industry for over 20 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.

Clifford V. Chamblee joined the Company in its ROV 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 managing the operations of Canyon including 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 Cal Dive International, Inc. (now known as

Helix). 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.

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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.

PART II

Item 5. Market for the Registrant's Common Equity, Related Shareholder 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
2010		
First Quarter	$ 14.80	$ 9.98
Second Quarter	$ 17.00	$ 9.70
Third Quarter	$ 11.32	$ 8.38
Fourth Quarter	$ 14.48	$ 10.88
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(1)	$ 19.69	$ 15.55

(1) Through February 22, 2012

On February 16, 2012, the closing sale price of our common stock on the NYSE was $18.65 per share. As of February 16, 2012, there were 351 registered shareholders and 24,054 beneficial stockholders 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, 2006 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: ATP Oil & Gas Corporation, Atwood Oceanics Inc., Cameron International Corporation, Dril-Quip, Inc., Energy XXI (Bermuda) Limited, FMC Technologies, Inc., McDermott International, Inc., Oceaneering International, Inc., Oil States International, Inc., Petrofac Ltd, Rowan Companies, Inc., Stone Energy Corp., Superior Energy Services, Inc., TETRA Technologies, Inc., and W&T Offshore, 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, 2011 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, 2006 in our common stock at the closing price on that date price and on December 31, 2006 in the three indices presented. We paid no cash dividends during the period presented. The cumulative total percentage returns for the period presented were as follows: our stock — (49.6%); the Peer Group — 56.5%; the OSX — 8.2%; and S&P 500- (11.3)%. These results are not necessarily indicative of future performance.

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

	As of December 31,					
	2006	2007	2008	2009	2010	2011
Helix	$100.0	$132.3	$ 23.1	$ 37.5	$ 38.7	$ 50.4
Peer Group Index	$100.0	$147.5	$ 53.3	$114.0	$159.6	$156.5
Oil Service Index	$100.0	$150.9	$ 60.7	$ 97.5	$122.6	$108.2
S&P 500	$100.0	$103.5	$ 63.7	$ 78.6	$ 88.7	$ 88.7

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, 2011	498,851	$ 13.06	497,412	
November 1 to November 30, 2011				
December 1 to December 31, 2011	265	16.91		
	499,116	$ 13.06	497,412	

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(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 14). In October 2011, we repurchased the then remaining available shares under stock buyback program. Additional shares became available under the stock buyback program in January 2012 (see footnote (3) below).

(3) Amount as of December 31, 2011. In January 2012, we issued approximately 0.4 million shares to certain of our employees. These grants will increase the number of shares available for repurchase by a corresponding amount (Note 12).

Item 6. Selected Financial Data.

The financial data presented below for each of the five years ended December 31, 2011, 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.

	Year Ended December 31,				
	2011	2010	2009 (1)	2008	2007
	(amounts in thousands, except per share data)				
Net revenues	$1,398,607	$ 1,199,838	$1,461,687	$2,114,074	$1,732,420
Gross profit	330,592	33,672	243,162	372,191	505,907
Operating income (loss) (2)	235,528	(94,656)	203,815	(414,222)	411,279
Equity in earnings of investments	22,215	19,469	32,329	31,854	19,573
Income (loss) from continuing operations	133,077	(124,153)	166,170	(580,245)	343,639
Income (loss) from discontinued operations, net of taxes			9,581	(9,812)	1,347
Net income (loss), including noncontrolling interests(3)	133,077	(124,153)	175,751	(590,057)	344,986
Net (income) loss applicable to noncontrolling interests	(3,098)	(2,835)	(19,697)	(45,873)	(29,288)
Net income (loss) applicable to Helix	129,979	(126,988)	156,054	(635,930)	315,698
Preferred stock dividends (4)	(40)	(114)	(54,187)	(3,192)	(3,716)
Net income (loss) applicable to Helix common shareholders	129,979	(127,102)	101,867	(639,122)	311,982
Adjusted EBITDAX, less Cal Dive (5)	$ 668,662	$ 430,326	$ 490,092	$ 575,272	$ 608,813
Basic earnings (loss) per share of common stock:					
Continuing operations	$ 1.23	(1.22)	$ 0.92	$ (6.94)	$ 3.40

Discontinued operations						0.09		(0.11)		0.02
Net income (loss) per common share	$	1.23	$	(1.22)	$	1.01	$	(7.05)	$	3.42
Diluted earnings (loss) per share of common stock:										
Continuing operations	$	1.22	$	(1.22)	$	0.87	$	(6.94)	$	3.25
Discontinued operations						0.09		(0.11)		0.01
Net income (loss) per common share	$	1.22	$	(1.22)	$	0.96	$	(7.05)	$	3.26
Weighted average common shares outstanding:										
Basic		104,528		103,857		99,136		90,650		90,086
Diluted		104,953		103,857		105,720		90,650		95,647

(1) Excludes the results of Cal Dive subsequent to June 10, 2009 following its deconsolidation from our consolidated financial statements (Notes 1, 2 and 3).

(2) Oil and gas property impairment charges totaled $132.6 million in 2011, $181.1 million in 2010, $120.6 million in 2009, $920.0 million in 2008 and $64.1 million in 2007. Our oil and gas 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 totaling $10.9 million in 2011, $8.3 million in 2010, $24.4 million in 2009, $32.9 million in 2008 and $26.7 million in 2007.

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(3) In 2009, we had $77.3 million of gains on the sales of Cal Dive common stock held by us. Also includes the impact of gains on Cal Dive equity transactions of $98.5 million for the year ended December 31, 2007. See Note 3 for additional information related to our transactions involving Cal Dive common stock.

(4) The amount in 2009, includes $53.4 million of beneficial conversion charges related to our convertible preferred stock (Note 11).

(5) This is a non-GAAP financial measure. See "Non-GAAP Financial Measures" below for an explanation of the definition and use of such measure as well as a reconciliation of these amount to each year's respective reported income (loss) from continuing operations.

			As of December 31,		
	2011	2010	2009 (1)	2008	2007
			(In thousands)		
Working capital	$ 548,066	$ 373,057	$ 197,072	$ 287,225	$ 48,290
Total assets	3,582,347	3,592,020	3,779,533	5,067,066 (2)	5,449,515
Long-term debt (including current maturities)	1,155,321	1,357,932	1,360,739	2,027,226	1,758,186
Convertible preferred stock	1,000	1,000(3)	6,000(3)	55,000	55,000
Total controlling interest shareholders' equity	1,421,403	1,260,604	1,405,257	1,191,149(2)	1,829,951
Noncontrolling interests	28,138	25,040	22,205	322,627	263,926
Total equity	1,449,541	1,285,644	1,427,462	1,513,776	2,093,877

(1) Reflects deconsolidation of Cal Dive effective June 10, 2009 (Notes 1, 2 and 3).

(2) Includes the $907.6 million of impairment charges recorded to reduce goodwill, intangible assets with indefinite lives and certain oil and gas properties to their estimated fair values.

(3) 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 11).

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 EBITDAX, a non-GAAP financial measure, that is commonly used in the oil and natural gas industry but is not a recognized accounting term under GAAP. We use EBITDAX 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 EBITDAX 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 to compare our results to other companies that have different financing, capital and tax structures.

We define EBITDAX as income (loss) from continuing operations plus income taxes, net interest expense and other, depreciation, depletion and amortization expense and exploration expenses. We separately disclose our non cash oil and gas property impairment charges, which, if not material, would be reflected as a component of our depreciation, depletion 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.

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 EBITDAX, we deduct the non-controlling interests related to the adjustment components of EBITDAX, the adjustment components of EBITDAX of any discontinued operations, the gain or loss on the sale of assets, and the portion of our asset impairment charges that are considered cash-related charges. Asset impairment charges that are considered cash are those that affect future cash outflows most notably those related to adjustment to our asset retirement obligations.

Other companies may calculate their measures of EBITDAX and Adjusted EBITDAX differently than we do, which may limit its usefulness as a comparative measure. Because EBITDAX 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 that GAAP financial measure. A reconciliation of our net income (loss) attributable to common shareholders to EBITDAX is as follows:

	Year Ended December 31,				
	2011	2010	2009	2008	2007
	(amounts in thousands)				
Income (loss) from continuing operations	$ 133,077	$(124,153)	$166,170	$ (580,245)	$ 343,639
Adjustments:					
Income tax provision (benefit)	14,903	(39,598)	95,822	86,779	171,862
Net interest expense and other	99,953	86,324	51,495	111,098	67,047
Depreciation, depletion and amortization expense	311,103	317,116	262,617	333,726	329,798
Asset impairment charges(1)	149,730	200,066	121,855	919,986	75,865
Exploration expenses	10,914	8,276	24,383	32,926	26,725
EBITDAX	719,680	448,031	722,342	904,270	1,014,936
Adjustments:					
Non-controlling interest in Cal Dive			(44,785)	(105,280)	(61,404)
Non-controlling interest in Kommandor LLC	(4,060)	(3,878)	(3,344)	102	(82)
Discontinued operations(2)		(16)	(290)	3,242	3,696
Gain on sales of assets	(5,278)	(9,405)	(79,362)	(73,471)	(202,064)
Asset impairments charges	(41,680)	(4,406)	(48,178)	(13,031)	
ADJUSTED EBITDAX	$ 668,662	$ 430,326	$546,383	$ 715,832	$ 755,082
ADJUSTED EBITDAX	$ 668,662	$ 430,326	$546,383	$ 715,832	$ 755,082
Less Cal Dive, net of non-controlling interests			(56,291)	(140,560)	(146,269)
ADJUSTED EBITDAX less Cal Dive	$ 668,662	$ 430,326	$490,092	$ 575,272	$ 608,813

(1) Includes impairment charges related to our oil and gas properties, other than temporary losses on our equity investments and any impairment charges associated with goodwill and other intangible assets. Amount in 2011 also includes a $6.6 million impairment charge related to our well intervention equipment in Australia (Note 2). The amount in 2007 also includes $11.8 million related to Cal Dive's impairment of an equity investment in

Offshore Technology Solutions Limited.

(2) Amounts are associated with Helix RDS Limited, our former reservoir technology consulting company that we sold in April 2009 (Note 1).

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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 reservoir development solutions and other contracting services to the energy market as well as to our own oil and gas properties. Our oil and gas business is a prospect generation, exploration, development and production company. Employing our own key services and methodologies, we seek to lower finding and development costs, relative to industry norms.

Our Strategy

Over the past three years, we have focused on improving our balance sheet by increasing our liquidity through dispositions of non-core business assets, decreasing our planned capital spending and reducing the amount of our debt outstanding. Our focus is to shape the future direction of the Company around our Contracting Services business that is comprised of our well operations, robotics and subsea construction services while supplementing these efforts with our production facilities business activities and the substantial cash flow associated with our oil and gas business through a combination of existing and/or future production from our properties and the sale of all or a portion of our oil and gas assets.

Since the beginning of 2009, we have generated approximately $600 million in pre-tax proceeds from dispositions of non-core business assets. These transactions included approximately $55 million from the sale of individual oil and gas properties, over $500 million from the sale of our stockholdings in CDI and $25 million for the sale of our former reservoir consulting business.

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. However, some of our Contracting Services, more specifically our subsea construction services, will often lag drilling operations by a period of 6 to 18 months, meaning that even if there were a sudden increase in deepwater permitting and subsequent drilling in the Gulf of Mexico, it probably would still be some time before we would start securing any awarded projects. The performance of our oil and gas 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:

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- 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;
- 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.

Oil prices increased significantly in 2011 (the average price for West Texas Intermediate ("WTI") crude oil was $94.88 per barrel in 2011 compared to $79.48 per barrel in 2010). Commencing in the latter part of the first quarter of 2011, the price that we received for the majority of our crude oil sales volumes increased significantly over the WTI market price. Historically the price we receive for most of our crude oil, as priced using a number of Gulf Coast crude oil price indexes, closely correlated with current market prices of WTI crude oil; however, because of a substantial increase in crude oil inventories at Cushing, Oklahoma the price of Gulf Coast crude is now substantially higher than WTI. Currently the price we receive for our crude oil more closely correlates with the Brent crude oil price in the North Sea.
The premium we received for our oil sales was anywhere from $8-$25 per barrel greater than the given WTI price during the affected months in 2011. We do not know how long the price variance of our crude oil and WTI will continue but most analysts believe this premium will continue over at least the first half of 2012.

Prices for natural gas have decreased significantly from the record highs in mid-2008 primarily reflecting the increased supply from non-traditional sources of natural gas such as production from shale formations and tight sands, as well as decreased demand following the economic downturn that commenced in mid-to-late 2008, and the currently warmer than expected winter conditions over most of the U.S. Although there have been signs that the economy may be improving, most economists believe that the recovery will be slow and the economy will take time to recover to previous levels. The oil and natural gas industry has been adversely affected by the uncertainty of the general timing and level of the economic recovery as well as the more recent uncertainties concerning increased government regulation of the industry in the United States (as further discussed below).

In April 2010, an explosion occurred on the Deepwater Horizon drilling rig located on the site of the Macondo well at Mississippi Canyon Block 252 (Note 1). The resulting events included loss of life, the complete destruction of the drilling rig and an oil spill the magnitude of which was unprecedented in U.S. territorial waters. In October 2010, the DOI lifted the deepwater drilling moratorium that had been in place since May 2010 and instructed the BOEMRE (now the BOEM and BSEE) that it could resume issuing drilling permits conditioned on the requesting company's compliance with all revised drilling, safety and environmental requirements. The BOEMRE resumed issuing deepwater drilling permits in late February 2011. See below for a discussion of our HFRS, which currently represents one of the containment systems that have been included in deepwater drilling permit applications with BOEMRE (now the BOEM and BSEE) under its new guidelines.

While we did not have any plans to drill any additional deepwater wells during the period covered by the drilling moratorium in 2010, our contracting services businesses rely heavily on industry investment in the Gulf of Mexico and the results of this drilling moratorium and subsequent delay in the drilling permit process has adversely affected our results of operations and financial position.   Although our contracting services activities during 2010 remained substantially unaffected, delays in restarting drilling in the deepwater of the Gulf of Mexico, due to failure to issue permits or otherwise, have resulted in a deferral or cancellation of portions of our contracted backlog and have decreased current opportunities for contracts for work in the Gulf of Mexico and may continue to affect future opportunities for work in the Gulf of Mexico.

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Furthermore, the continuing delays in the permitting process and any subsequent related developments in the Gulf of Mexico could require us to pursue relocation of our vessels located in the Gulf of Mexico to other international locations, such as the North Sea, West Africa, Southeast Asia, Brazil and Mexico.

Although we are still feeling the effects of the recent global recession and are beginning to experience the consequences of the additional regulatory requirements resulting from the aftermath of the oil spill in the Gulf of Mexico, 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 requires the need for continual replenishment of oil and gas production; (2) peaking global production rates; (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. Our strategy of combining contracting services operations and oil and gas operations allows us to focus on trends (4) through (6) in that we pursue long-term sustainable growth by applying specialized subsea services to the broad external offshore market but with a complementary focus on marginal fields and new reservoirs in which we currently have an equity stake.

At December 31, 2011, we had cash on hand of $546.5 million and $558.6 million available for borrowing under our revolving credit facilities. Our capital expenditures for 2012 are expected to total approximately $445 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

We have continued to evolve our business model by completing a variety of transactions and activities that we believe will continue to have significant impacts on our financial position, results of operations and cash flow. In 2005 and 2006, we acquired the majority of our oil and gas operations, including in large part the July 2006 acquisition of Remington Oil and Gas Corporation, an exploration, development and production company, for approximately $1.4 billion paid with a combination of cash and Helix common stock and the assumption of $358.4 million of liabilities. In March 2006, we changed our name from Cal Dive International, Inc. to Helix Energy Solutions Group, Inc., leaving the “Cal Dive” name to our former Shelf Contracting subsidiary (see “Reduction in Ownership of Cal Dive” below), and in December 2006 completed a carve-out initial public offering of Cal Dive, selling a 26.5% stake and receiving pre-tax net proceeds of $264.4 million and a pre-tax dividend of $200 million derived from borrowings under the Cal Dive revolving credit facility.

During 2006 we committed to four capital projects that have expanded and will continue to expand our contracting services capabilities:

- upgrading of the Q4000;
- construction of a multi-service DP dive support/well intervention vessel (Well Enhancer). The Well Enhancer joined our fleet in October 2009;
- conversion of the Caesar into a deepwater pipelay vessel; the Caesar was commissioned into our fleet in May 2010; and
- conversion of a ferry vessel into a DP floating production unit (the Helix Producer I or HP I); the HP I was commissioned in April 2009 and its production facilities upgrades were certified and placed in service in June 2010.

During 2007, we successfully completed the drilling of exploratory wells in our Bushwood prospect located in Garden Banks Blocks 462, 463, 506 and 507 in the Gulf of Mexico. In January 2009, we announced an additional discovery at the Bushwood field as well as the commencement of initial sustained production from the field. Production from the Bushwood field increased in early 2010 following completion of long delayed repairs of a third party pipeline providing service to the field as well as the development of a substantial amount of our proved undeveloped oil reserves at the field. Oil production from the Danny reservoir within the Bushwood field commenced in early February 2010. On October 19, 2010, we reestablished production from our Phoenix field at Green Canyon Blocks 236, 237, 238 and 282, using the HP I as the field's production unit.

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In February 2012, we announced that we are initiating construction of a new multi-service semi-submersible well intervention and well operations vessel similar to our existing Q4000 vessel. This vessel is expected to be completed and placed in service in 2015 at an approximate estimated cost of $525 million.

Reduction in Ownership of Cal Dive

At December 31, 2008, we owned 57.2% of Cal Dive. In January 2009, we sold approximately 13.6 million shares of Cal Dive common stock held by us to Cal Dive for $86 million. This transaction reduced our ownership in Cal Dive to approximately 51%.

In June 2009, we sold 22.6 million shares of Cal Dive held by us pursuant to an underwritten secondary public offering ("Offering"). Proceeds from the Offering totaled approximately $182.9 million, net of underwriting fees. Separately, pursuant to a Stock Repurchase Agreement with Cal Dive, simultaneously with the closing of the Offering Cal Dive repurchased from us approximately 1.6 million shares of its common stock for net proceeds of $14 million at $8.50 per share, the Offering price. Following the closing of these two transactions, our ownership of Cal Dive common stock was reduced to approximately 26%.

Because these transactions reduced our ownership in Cal Dive to less than 50%, the $59.4 million gain resulting from the sale of these shares is reflected in "Gain (loss) on investment in Cal Dive common stock" in the accompanying consolidated statement of operations. Because we no longer held a controlling interest in Cal Dive, we ceased consolidating Cal Dive effective June 10, 2009, the closing date of the Offering, and we commenced accounting for our remaining ownership interest in Cal Dive under the equity method of accounting until September 23, 2009 as discussed below.

On September 23, 2009, we sold 20.6 million shares of Cal Dive common stock held by us pursuant to a second secondary public offering ("Second Offering"). On September 24, 2009, the underwriters sold an additional 2.6 million shares of Cal Dive common stock held by us pursuant to their overallotment option under the terms of the Second Offering. The price for the Second Offering was $10 per share, with resulting proceeds totaling approximately $221.5 million, net of underwriting fees. We recorded a $17.9 million gain associated with the Second Offering transaction, which was recorded as a component of "Gain (loss) on investment in Cal Dive common stock" in the accompanying consolidated statement of operations.

In March 2011, we sold our remaining 0.5 million shares of Cal Dive common stock in open market transactions for $3.6 million in gross proceeds, which resulted in a pre-tax gain of approximately $0.8 million (Note 3). For more information regarding the reduction in our ownership in Cal Dive see Notes 1, 2 and 3.

Results of Operations

Our operations are conducted through two lines of business: contracting services and oil and gas. We have disaggregated our contracting services operations into two reportable business segments, which are Contracting Services and Production Facilities. Our third business segment is Oil and Gas. In June 2009, we ceased consolidating the results and operations of Cal Dive, our former Shelf Contracting business segment, following the sale of a substantial amount of our remaining ownership of Cal Dive (Note 3). Each line item within our consolidated statement of operations for the years ended December 31, 2010 is impacted significantly when compared to the year ended December 31, 2009 as a result of the deconsolidation of the Cal Dive results. Our 2009 consolidated results include Cal Dive's results through June 10, 2009 and we recorded our approximate 26% share of Cal Dive's results for the period June 11, 2009 through September 23, 2009 to equity in earnings of investments as required under the equity method of accounting. We continued to disclose the operating results of the Shelf Contracting business as a segment through June 10, 2009.

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

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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 our well operations, robotics and subsea construction services. 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 7). 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. As of December 31, 2011, our Contracting Services had backlog of approximately $490.3 million, including $471.8 million expected to be performed in 2012. Backlog for the HP I totaled approximately $49.4 million at December 31, 2011, including $33.3 million expected to be serviced in 2012. At December 31, 2010, our combined backlog for both Contracting Services and the HP I totaled $267.3 million. These backlog contracts are cancellable without penalty in many cases. Backlog is not a reliable indicator of total annual revenue for our Contracting Services businesses as contracts may be added, cancelled and in many cases modified while in progress.

Oil and Gas Operations

We began our oil and gas operations to achieve incremental returns, to expand our off-season utilization of our Contracting Services assets, and to provide a more efficient solution to offshore abandonment. We have evolved this business model to include not only mature oil and gas properties but also proved and unproved reserves yet to be developed and explored. By owning oil and gas reservoirs and prospects, we are able to utilize the services we otherwise provide to third parties to create value at key points in the life of our own reservoirs including during the exploration and development stages, the field management stage, and the abandonment stage. It is also a feature of our business model to opportunistically monetize part of the created reservoir value, through sales of working interests, in order to help fund field development and reduce gross profit deferrals from our Contracting Services operations. Therefore the reservoir value we create is realized through oil and gas production and/or monetization of working interest stakes.

Discontinued Operations

In April 2009, we sold Helix RDS Limited, our former reservoir technology consulting company, to a subsidiary of Baker Hughes Incorporated for $25 million. We have presented the results of Helix RDS as discontinued operations in the accompanying consolidated financial statements (Note 1). There were no material results from discontinued operations in the years ended December 31, 2011 and 2010. Helix RDS was previously a component of our Contracting Services business. We recognized an $8.3 million gain on the sale of Helix RDS.

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,		Increase/
	2011	2010	(Decrease)
Revenues (in thousands) –			
Contracting Services	$ 738,235	$ 780,339	$ (42,104)
Oil and Gas	696,607	425,369	271,238
Production facilities	75,460	117,300	(41,840)
Intercompany elimination	(111,695)	(123,170)	11,475
	$ 1,398,607	$ 1,199,838	$ 198,769

Gross profit (loss) (in thousands) –			
Contracting Services(1)	$ 137,444	$ 132,723	$ 4,721
Oil and Gas(2)	156,967	(140,714)	297,681
Production facilities	39,170	64,203	(25,033)
Corporate	(3,082)	(3,428)	346
Intercompany elimination	93	(19,112)	19,205
	$ 330,592	$ 33,672	$ 296,920

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	Year Ended December 31, 2011	2010	
Gross Margin –			
Contracting Services	19%	17%	2pts
Oil and Gas (1)	23%	(33)%	56pts
Production facilities	52%	55%	(3)pts
Total company	24%	3%	21pts
Number of vessels(3)/ Utilization(4) –			
Contracting Services:			
Pipelay and Robotics support vessels	8/76%	7/84%	
Well operations	3/90%	4/83%	
ROVs/Trenchers/ROVDrill Units	46/60%	46/62%	

(1) Included a $6.6 million charge in 2011 to partially impair our subsea well intervention equipment located in Australia (Note 2).

(2) Included asset impairment charges of oil and gas properties totaling $132.6 million in 2011 and $181.1 million in 2010. These amounts also include exploration expenses totaling $10.9 million in 2011 and $8.3 million in 2010, which primarily reflect the write off of expiring leasehold costs (Note 5).

(3) Represented number of vessels as of the end 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 operations vessels count included one vessel chartered by us from our Australian joint venture company (Note 7).

(4) 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 were as follows (in thousands):

	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 were 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)

As disclosed in Item 2. “Properties” elsewhere in this Annual Report, all of our current oil and gas operations are located in the U.S. Gulf of Mexico. We have one property located offshore of the United Kingdom (“U.K.”). We plan to substantially complete the plugging of the wells and removal of the structures from this field in 2012 in accordance with the applicable U.K. regulations (Note 5). We had no revenue associated with our U.K. oil and gas operations in 2011 or 2010. The total operating costs associated with our U.K. oil and gas operations totaled $4.0 million and $3.7 million in 2011 and 2010, respectively.

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

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	Year Ended December 31, 2011	2010	Increase/ (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 increase 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
Miscellaneous revenues 1	$ 7,478	$ 10,005	$ (2,527)

(1) Miscellaneous revenues primarily relate to fees earned under our process handling agreements.

Presenting the expenses of our Oil and Gas segment on a cost per barrel of production basis normalizes for the impact of production gains/losses and provides a measure of expense control efficiencies. 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)	$ 130,182	$ 14.97	$ 87,688	$ 11.14
Workover (3)	16,534	1.90	23,156	2.94
Transportation	8,589	0.99	6,924	0.88
Repairs and maintenance	12,256	1.41	8,033	1.02
Overhead and company labor	12,682	1.46	9,884	1.26
Sub Total	$ 180,243	$ 20.73	$ 135,685	$ 17.24
Depletion and amortization	$ 205,035	$ 23.58	$ 219,773	$ 27.92
Abandonment	803	0.09	1,050	0.13
Accretion	14,880	1.71	15,517	1.97
Impairments (Note 5)	132,603	15.25	181,083	23.01
Net hurricane (reimbursements) costs	(4,838)	(0.55)	4,699	0.60
	348,483	40.08	422,122	53.63
Total	$ 528,726	$ 60.81	$ 557,807	$ 70.87

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(1) Excludes exploration expense 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 charges resulting from Hurricane Ike in September 2008. Amounts in 2010 primarily reflect efforts to resolve production issues at both our Bushwood and East Cameron Block 346 fields.

In the following disclosure regarding our results of operations please refer to the tables above and Note 17 for supplemental information regarding our business segment results. Our disclosures specifically refer to our Contracting Services, Production Facilities and Oil and Gas segments.

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 Gulf oil spill 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. In 2012, we expect our three well intervention vessels as well as one of our pipelay/construction vessels to be subject to a regulatory dry dock, with the majority of these dry docks expected to occur in the first half of 2012. As previously noted our Q4000, Express and HP I vessels were involved in the Gulf oil spill response and containment efforts in the second and third quarters of 2010.

Oil and Gas revenues increased 64% in 2011, as compared to 2010, reflecting increased oil production and higher oil prices. Our production increased by 824 MBOE, as compared to 2010. Our production for 2011 benefited from a full year of oil production from our 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 our Bushwood field.

Our Production Facilities revenues decreased 36% in 2011, reflecting a full year's utilization of the HP I at the Phoenix field (which is owned 70% by us) as compared to utilization by a third party in the Gulf oil spill response 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 benefitted from our increased scope of internal work related to our oil and gas properties as well as the Express and Q4000 both being contracted to participate in the Gulf oil spill response and containment efforts.

The Oil and Gas gross profit increase of $297.7 million for 2011, over 2010, was due primarily to increased oil production and higher oil price realizations. The increase in our production is primarily related to the commencement of production from our Phoenix field in October 2010. Our oil and gas gross profit was adversely affected by impairment charges totaling $132.6 million in 2011 and $181.1 million in 2010. See Note 5 for additional disclosure regarding our impairment charges covering the periods covered by this Annual Report.

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, which is owned 70% by us, as opposed to approximately five months of third party utilization during the Gulf oil spill response and containment efforts in 2010.

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Gain on Sale of Assets, Net. Gain on sale of assets, net, was $4.5 million in 2011 compared to a gain of $9.4 million in 2010. In December 2011, we sold our interest in the Jake field at Green Canyon Block 490 for approximately $31 million in pre-tax gross proceeds. In 2010, we completed a sale of unused equipment relating to our Contracting Services business, which resulted in a $3.2 million gain. The majority of our remaining gain in 2010 was associated with the acquisition of the 50% working interest held by our former co-owner in the Camelot field in the United Kingdom. See Note 5 for additional information regarding our acquisition and dispositions of oil and gas properties.

Selling, General and Administrative Expenses. Selling, general and administrative expenses totaled $99.6 million in 2011, which was $22.5 million lower than expenses incurred in 2010. The decrease primary 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 (Note 16).

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 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 7). 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 disruptions caused by Tropical Storm Lee in early September 2011.

Other Than Temporary Impairment Loss. In December 2011, our joint partner in 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 7).

Net Interest Expense. We reported net interest expense of $95.8 million in 2011 as compared to $85.3 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. The decrease in capitalized interest was offset by lower interest rates and lower levels of debt since year end 2010. Interest income increased to $2.1 million in 2011 from $1.4 million in 2010, reflecting our substantially higher cash balances.

Other Income (Expense). Other expense totaled $4.2 million in 2011 as compared to $1.0 million for 2010. The increase in other expense primarily reflects 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 $0.9 million in 2010. In 2011, other expense also includes the $2.4 million premium we paid to early extinguish approximately $75.0 million of Senior Unsecured Notes we purchased during the year (Note 9).

Provision for Income Taxes A provision for income taxes of $14.9 million was recorded in 2011 compared to an income tax benefit of $39.6 million in 2010. The variance primarily reflects increased profitability in 2011. The effective tax rate for 2011 was 10.1%; this was more favorable than the 24.2% tax benefit that was recorded for 2010. 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 business.

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Comparison of Years Ended December 31, 2010 and 2009

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

	Year Ended December 31, 2010	Year Ended December 31, 2009	Increase/ (Decrease)
Revenues (in thousands) –			
Contracting Services	$ 780,339	$ 796,158	$ (15,819)
Shelf Contracting(1)	—	404,709	(404,709)
Oil and Gas	425,369	385,338	40,031
Production facilities	117,300	3,395	113,905
Intercompany elimination	(123,170)	(127,913)	4,743
	$1,199,838	$ 1,461,687	$ (261,849)
Gross profit (loss) (in thousands) –			
Contracting Services	$ 132,723	$ 148,375	$ (15,652)
Shelf Contracting(1)	—	92,728	(92,728)
Oil and Gas(2)	(140,714)	21,788	(162,502)
Production facilities	64,203	(3,478)	67,681
Corporate	(3,428)	(2,797)	(631)
Intercompany elimination	(19,112)	(13,454)	(5,658)
	$ 33,672	$ 243,162	$ (209,490)
Gross Margin –			
Contracting Services	17%	19%	(2)pts
Shelf Contracting(1)	N/A	23%	(23)pts
Oil and Gas (2)	(33)%	6%	(39)pts
Production facilities	55%	N/A	55 pts
Total company	3%	17%	(14)pt
Number of vessels(3)/ Utilization(4) –			
Contracting Services:			
Pipelay and Robotics support vessels	7/84%	7/79%	
Well operations	4/83%	3/82%	
ROVs/Trenchers/ROVDrill Units	46/62%	47/68%	

1(1) Represented results of our former majority-owned subsidiary, CDI. We deconsolidated CDI from our financial statements in June 2009 (see "Reduction in Ownership of Cal Dive" above and Note 3).

2(2) Included oil and gas property asset impairment charges totaling $181.1 million in 2010 and $120.6 million in 2009. These amounts also include exploration expenses totaling $8.3 million in 2010 and $24.4 million in 2009, which primarily reflect the write off of expiring leasehold costs (Note 5).

(3) Represented number of vessels as of the end 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 operations vessels count included one vessel chartered by us from our Australian joint venture.

4(4) 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.

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Intercompany segment revenues during the years ended December 31, 2010 and 2009 were as follows (in thousands):

	Year Ended December 31, 2010	2009	Increase/ (Decrease)
Contracting Services	$109,012	$ 120,048	$ (11,036)
Production Facilities	14,158	—	14,158
Shelf Contracting	—	7,865	(7,865)
	$123,170	$ 127,913	$ (4,743)

Intercompany segment profit during the years ended December 31, 2010 and 2009 was as follows (in thousands):

	Year Ended December 31, 2010	2009	Increase/ (Decrease)
Contracting Services	$ 15,655	$ 13,205	$ 2,450
Production Facilities	3,457	(116)	3,573
Shelf Contracting	—	365	(365)
	$ 19,112	$ 13,454	$ 5,658

Our U.K. oil and gas revenues totaled $1.0 million in 2009 on production volumes of 0.2 Bcfe. The total operating costs associated with our U.K. oil and gas operations totaled $3.7 million in both 2010 and 2009. The following table details various financial and operational highlights related to our Oil and Gas segment for the periods presented:

	Year Ended December 31, 2010	2009	Increase/ (Decrease)
Oil and Gas information–			
Oil production volume (MBbls)	3,354	2,741	613
Oil sales revenue (in thousands)	$252,445	$183,973	$ 68,472
Average oil sales price per Bbl (excluding hedges)	$ 78.46	$ 64.15	$ 14.31
Average realized oil price per Bbl (including hedges)	$ 75.27	$ 67.11	$ 8.16
Increase in oil sales revenue due to:			
Change in prices (in thousands)	$ 22,359		
Change in production volume (in thousands)	46,113		
Total increase in oil sales revenue (in thousands)	$ 68,472		

	Year Ended December 31, 2010	2009	Increase/ (Decrease)
Gas production volume (MMcf)	27,097	27,334	(237)
Gas sales revenue (in thousands)	$ 162,919	$ 122,335	$ 40,584

Average gas sales price per mcf (excluding hedges)	$ 4.67	$ 4.15	$ 0.52
Average realized gas price per mcf (including hedges)	$ 6.01	$ 4.48	$ 1.53
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$ 42,005		
Change in production volume (in thousands)	(1,421)		
Total increase in gas sales revenue (in thousands)	$ 40,584		
Total production (MBOE)	7,870	7,297	573
Price per barrel	$ 52.78	$ 42.00	$ 10.78
Oil and Gas revenue information (in thousands)-			
Oil and gas sales revenue	$ 415,364	$ 306,308	$ 109,056
Miscellaneous revenues(1)	$ 10,005	$ 79,030	$ (69,025)

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(1) Miscellaneous revenues primarily relate to fees earned under our process handling agreements. The amount in 2009 also includes $73.5 million of accrued royalty payments previously involved in a legal dispute. These accrued royalties were reversed in January 2009. See Note 5, for additional information regarding the resolution of our royalty dispute.

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

	Year Ended December 31,			
	2010		2009	
	Total	Per Barrel	Total	Per Barrel
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$ 87,688	$ 11.14	$ 78,348	$ 10.74
Workover (3)	23,156	2.94	9,790	1.34
Transportation	6,924	0.88	8,209	1.12
Repairs and maintenance	8,033	1.02	13,469	1.85
Overhead and company labor	9,884	1.26	10,020	1.37
Sub Total	$ 135,685	$ 17.24	$ 119,836	$ 16.42
Depletion and amortization	$ 219,773	$ 27.92	$ 154,052	$ 21.11
Abandonment	1,050	0.13	4,369	0.60
Accretion	15,517	1.97	15,204	2.09
Impairments (4)	181,083	23.01	69,038	9.46
Net hurricane (reimbursements) costs (5)	4,699	0.60	(23,332)	(3.20)
	422,122	53.63	219,331	30.06
Total	$ 557,807	$ 70.87	$ 339,167	$ 46.48

(1) Excludes exploration expense of $8.3 million and $24.4 million for the years ended December 31, 2010 and 2009, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

(3) Excludes all hurricane-related costs and charges resulting from Hurricane Ike in September 2008 (see (5) below). Increase in 2010 primarily reflects our first quarter of 2010 efforts to resolve production issues at both our Bushwood and East Cameron Block 346 fields.

(4) Includes impairment charges for certain oil and gas properties exclusive of hurricane related charges discussed in (5) below.

(5) Amounts related to damages sustained from Hurricane Ike in September 2008 (Note 4). Hurricane-related impairments and adjustments to asset retirement obligations totaled $51.5 million in 2009.

Revenues. Our total revenues decreased by 18% in 2010 as compared to 2009 primarily reflecting the disposition of our Shelf Contracting business operations in June 2009 (see “Reduction of Cal Dive Ownership” above and Note 3). Excluding the effect of removing revenues associated with our former Shelf Contracting business our total revenues increased by 14% in 2010 as compared to those recognized in 2009.

Contracting Services revenues decreased 2% in 2010 as compared to 2009. The decrease reflects a higher amount of internal vessel utilization for development of our oil and gas properties in the first half of 2010, the scheduled regulatory dry docking of our Seawell vessel in February 2010, and the completion of a large international construction project in the third quarter of 2009 ($121 million of revenues in 2009). Overall the utilization levels for our vessels increased in 2010 as compared to 2009; however, the total number and utilization rate for our ROVs decreased slightly. Our revenues in 2010 benefitted from two Contracting Services vessels being added to our fleet subsequent to September 30, 2009 (the Well Enhancer in October 2009 and the Caesar in May 2010). As previously noted, our Q4000 and Express vessels participated extensively in the Gulf oil spill response and containment efforts. These vessels were released by the contractor, BP, in October 2010. In order to be contracted by BP, these vessels had to defer other projects from their existing backlog.

Our Production Facilities revenues increased substantially in 2010 reflecting the HP I being placed in service in June 2010, following the final installation of its production processing facility upgrades and receipt of its certification by U.S. Coast Guard. Just prior to the HP I beginning service to our Phoenix field, the vessel was contracted by BP to assist in the Gulf oil spill response and containment efforts. The HP I was released by BP in early October; it then re-mobilized to the Phoenix field where production commenced on October 19, 2010. The HP I remains in the Phoenix field, where it is expected to remain until the field depletes.

Oil and Gas revenues increased by 10% in 2010 as compared to 2009. The increase is attributable to a significant increase in the realized prices of both oil (12%) and natural gas (34%) as compared to amounts realized in 2009. Our production also increased by 573 MBOE as compared to the same period in 2009. The increase in sales volumes primarily reflects the incremental production from the Bushwood field following certain recompletion and development activities that were completed in the first quarter of 2010, including the development of the Danny oil reservoir with initial production in February 2010 and the reestablishment of production from the Phoenix field in October 2010 (this field last produced in 2005 when it was owned by others (Note 5)).

Our oil and gas revenues for the year ended December 31, 2009 benefitted from $73.5 million of accrued royalty payments that were previously in dispute. Following a favorable appellate judicial ruling in January 2009, we reversed these amounts as oil and gas revenues in the first quarter of 2009 and began accounting for the additional oil and gas revenues associated with the previously disputed royalty net revenue interest (Note 5).

Gross Profit. Gross profit for 2010 decreased by $209.5 million as compared to 2009. Excluding the effect of our former Shelf Contracting business, our continuing businesses gross profit decreased by $116.8 million, or 78%, in 2010 as compared to 2009.

Contracting Services gross profit decreased by $15.7 million, or 11%, in 2010 from 2009. We generally experienced higher utilization for our vessels in 2010 than in 2009. The majority of our subsea construction and well operations contracts were performed at rates yielding favorable margins during the first half of 2010; however, much of those services represented internal work for the development of our oil and gas properties, most notably the Bushwood field. Two of our Contracting Services vessels, the Q4000 and the Express, participated extensively in the Gulf oil spill response and containment efforts. Other than our participation in these efforts, our U.S. Gulf of Mexico operations began to diminish in the latter part of 2010 as our existing backlog of previously negotiated service contracts decreased either by our completion of certain contracted work or in many cases, the deferral of projects in the deepwater pending receipt of regulatory approvals that were halted by the U.S. Department of Interior issuance of a drilling moratorium from April 2010 to October 2010. Although the deepwater moratorium was lifted in October 2010, no permits were issued until late February 2011.

Our Contracting Services gross profit was also adversely affected rather significantly by two specific projects in 2010. One project represented the initial pipelay contract work for our Caesar vessel, that was commissioned in May 2010. The approximate $12 million loss on this project primarily reflected start-up and weather-related issues. The other project that resulted in a significant loss in 2010 was located offshore China. Our WOSEA subsidiary was contracted by a Chinese company to perform a large field abandonment project, and WOSEA chartered the Normand Clough vessel from the Australian joint venture to perform the project. Even though we expected the abandonment of the subsea wells would be challenging, the project proved to be much more difficult than we anticipated from a structural standpoint reflecting the condition of the wells, start-up issues related to utilizing the repaired subsea intervention device (“SID”), and lastly and most notably weather-related issues in the China Sea. We had initially expected to complete the job by the end of October 2010, but because of the combination of the aforementioned factors we did not leave the field until early February 2011, and only after it was mutually agreed to reduce the project's original scope of work. The total pre-tax operating loss associated with this project was approximately $30 million in 2010 (see "Liquidity and Resources - Contingencies" below).

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Our Oil and Gas segment's gross profit decreased by $162.5 million, which includes greater year-over-year property impairment charges, totaling $181.1 million in 2010 and $120.6 million in 2009, partially offset by a decrease in exploration expenses totaling $8.3 million in 2010 and $24.4 million in 2009. Separately, following the significant reduction in estimates of proved reserves during 2010 (Notes 5 and 19), the depletion rate for many of our oil and gas fields increased substantially, most notably at our Bushwood field where our revised depletion rate resulted in an incremental $72.3 million of depletion expense in 2010. Our Oil and Gas gross profit in 2009 benefitted from the resolution of the $73.5 million of previously disputed royalty payments and $23.3 million of insurance reimbursements in excess of hurricane related costs incurred during the year ended December 31, 2009 (Note 4). See Note 5 for a discussion of our oil and gas impairment charges for 2010 and 2009.

The substantial increase in our Production Facilities' gross profit ($67.7 million) reflects the HP I commencing contract work in 2010. The HP I was first utilized in the Gulf oil spill response and containment efforts from June to October 2010 and has since been engaged to process production for our Phoenix field, where production commenced on October 19, 2010.

Goodwill impairments. In November 2010, in connection with our annual assessment of goodwill, we concluded that the $16.7 million of goodwill attributed to our Australian well operations subsidiary was impaired and we charged the full amount of its goodwill to expense in the fourth quarter of 2010 (Note 2).

Gain on Sale of Assets, Net. Gain on sale of assets, net, was $9.4 million in 2010 compared to a gain of $2.0 million in 2009. In the fourth quarter of 2010, we completed a sale of unused equipment relating to our Contracting Services business, which resulted in a $3.2 million gain. The majority of our remaining gain in 2010 was associated with the acquisition of the remaining 50% working interest in our Camelot field in the United Kingdom (Note 5). The gain in 2009 related to the sale of the East Cameron Block 316 and our remaining 10% ownership interest in the Bass Lite field in January 2009.

Selling, General and Administrative Expenses. Selling, general and administrative expenses totaled $122.1 million in 2010, which was $8.8 million lower than expenses incurred in 2009. Selling, general and administrative expenses associated with our former Shelf Contracting business totaled $33.7 million for the period prior to its deconsolidation in June 2009. Excluding the selling and administrative expenses associated with our former Shelf Contracting business, our selling, general and administrative expenses increased $24.9 million in 2010 as compared to 2009. The increase primary reflects a $17.5 million charge related to settlement of litigation in Australia involving the termination of an international construction contract within our Contracting Services segment. The increase in 2010 also reflects recognizing $4.1 million of bad debt expense within our Contracting Services segment, including one $4.0 million allowance for doubtful account reserve related to a separate international construction contract (Note 16).

Equity in Earnings of Investments. Equity in earnings of investments decreased by $12.9 million in 2010 as compared to 2009. This decrease primarily reflects $8.1 million related to our approximate 26% ownership interest in Cal Dive that was accounted for under the equity method accounting from June 10, 2009 to September 23, 2009 following its deconsolidation (Note 3). The remainder of our equity in earnings of investments included a decrease of $4.0 million for our share of Independence Hub reflecting periodic disruptions of production in the eastern Gulf of Mexico, primarily attributable to pipelines being shut in for repairs. Earnings related to our investment in Deepwater Gateway increased by $0.8 million in 2010 as compared to 2009 reflecting increased throughput at the facility following the repair of certain hurricane related damage that affected production from the fields processed through the Marco Polo TLP. Lastly, our Australian joint venture yielded a $3.6 million loss in 2010 primarily representing start-up costs associated with its operations.

Net Interest Expense and Other. We reported net interest and other expense of $86.3 million in 2010 as compared to $51.5 million in 2009. Interest and other expense associated with Cal Dive totaled $6.6 million prior to deconsolidation in June 2009. Excluding Cal Dive, gross interest expense was $99.2 million for both 2010 and 2009 Capitalized interest decreased to $12.5 million in 2010 compared to $48.1 million

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in 2009 reflecting the completion of our major capital projects, including the construction of the Well Enhancer, the conversions of the Caesar and HP I, and the development of our Bushwood and Phoenix fields. The decrease in capitalized interest was offset by lower interest rates and lower levels of debt since year end 2009. We recorded $2.6 million of unrealized losses associated with mark-to-market adjustments related to our foreign exchange contracts in 2010 as compared to $3.3 million of unrealized gains in 2009. Interest income increased to $1.4 million in 2010 from $0.9 million in 2009, reflecting our higher cash balances.

Provision for Income Taxes An income tax benefit of $39.6 million was recorded in 2010 compared to an income tax expense of $95.8 million in 2009. The variance primarily reflects decreased profitability in the current year. The effective tax rate for 2010 was a 24.2% benefit; this was less favorable than the 36.6% tax provision that was recorded for 2009. 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, which was slightly offset by effects of the deconsolidation of CDI in 2009.

Liquidity and Capital Resources

Overview

The following tables present certain information useful in the analysis of our financial condition and liquidity for the periods presented (in thousands):

	2011	2010
Net working capital	$ 548,066	$ 373,057
Long-term debt(1)	$1,147,444	$1,347,753
Liquidity(2)	$1,105,065	$ 787,296

(1) Long-term debt does not include the current maturities portion of the long-term debt as that amount is included in net working capital.

(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 carrying amount of our debt, including current maturities as of December 31, 2011 and 2010, is as follows (amount in thousands):

	2011	2010
Term Loan (matures July 2015) (1)	$ 279,750	$ 410,441
Revolving Credit Facility (matures July 2015) (1)		
Convertible Senior Notes (matures March 2025) (2)	290,445	281,472
Senior Unsecured Notes (matures January 2016)	474,960	550,000
MARAD Debt (matures February 2027)	110,166	114,811
Loan Notes		1,208
Total	$ 1,155,321	$ 1,357,932

(1)

Represents earliest date debt would mature; see Note 9 for conditions that would provide extension of the maturity date.

(2) This amount is net of the unamortized debt discount of $9.6 million and $18.5 million, respectively. The notes will increase to the $300 million face amount through accretion of non-cash interest charges through 2012. Notes may be redeemed by holders beginning in December 2012 (see "Contractual Commitments and Commercial Commitments" below and Note 9).

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	Year Ended December 31,		
	2011	2010	2009
Net cash provided by (used in):			
Operating activities	$ 567,156	$ 331,454	$ 417,677
Investing activities	$ (182,317)	$ (181,556)	$ (68,532)
Financing activities	$ (229,895)	$ (29,279)	$ (300,709)

As of December 31, 2011, our liquidity totaled $1.1 billion, including cash and cash equivalents of $546.5 million and $558.6 million of available borrowing capacity under our Revolving Credit Facility (Note 9).

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 also intend to repay debt with any additional free cash flow from operations and/or cash received from any dispositions of our non- core business assets. Historically, we have funded our capital program, including acquisitions, with cash flow 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 may reduce planned capital spending and seek further additional dispositions of our non-core business assets (see “Executive Summary” above). We also have a reasonable basis for estimating our future cash flow supported by our remaining Contracting Services backlog and the hedged portion of our estimated oil and gas production through 2013. We believe that internally generated cash flow and available borrowing capacity under our amended Revolving Credit Facility will be sufficient to fund our operations throughout 2012. In the first half of 2009, we repaid the remaining $349.5 million of borrowings outstanding under our Revolving Credit Facility. At December 31, 2011, we had no borrowings outstanding under our Revolving Credit Facility.

In accordance with our Credit Agreement, Senior Unsecured Notes, Convertible Senior Notes and the MARAD debt, we are required to comply with certain covenants and restrictions, including certain financial ratios such as collateral coverage, interest coverage, consolidated indebtedness leverage, and the maintenance of minimum net worth, working capital and debt-to-equity requirements. The 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 provide for our subsidiaries to incur project financing indebtedness (such as our MARAD loan) secured by the underlying asset, provided that the 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 equal to the amount of proceeds received from such occurrences (or at least 60% of the proceeds from the disposition of certain assets). Such prepayments will be applied first to the Term Loan, and any excess will then be applied to the Revolving Loans. As of December 31, 2011 and 2010, we were in compliance with all of our debt covenants and restrictions.

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 Convertible Senior Notes can be converted prior to stated maturity under certain triggering events specified in the indenture governing the Convertible Senior Notes. To the extent we do not have cash on hand or long-term financing secured to cover the conversion, the Convertible Senior Notes would be classified as a current liability in the accompanying consolidated balance sheet. No conversion triggers were met during the years ended December 31, 2011 and 2010. The holders may redeem the Convertible Senior Notes beginning December 2012 (Note 9). As the holders have this option, we

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assessed whether or not this debt was required to be classified as a current liability at December 31, 2011 but concluded this debt still qualified as a long term debt because: a) we possess enough borrowing capacity under our Revolving Credit Facility (matures July 2015) to settle the Convertible Senior Notes in full and b) it is our intent to utilize our Revolving Credit Facility borrowing capacity or other alternative financing proceeds to settle our Convertible Senior Notes, if and when the holders exercise their redemption option.

In June 2011, the Credit Agreement was amended 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 (Note 22). Under terms of this amendment, the lenders will provide us $100 million in additional proceeds under a new term loan (Term Loan A). The terms of the new Term Loan A are the same as those regarding the Revolving Credit Facility, with the Term Loan A requiring $5 million annual amortization of the principal balance. The Term Loan A will fund in March 2012 and we plan to use these proceeds and $100 million of existing liquidity to redeem $200 million in principal of our Senior Unsecured Notes outstanding. See Note 9 for additional information related to our long-term debt, including more information regarding our June 2011 and other amendments of our Credit Agreement and our requirements and obligations under the debt agreements.

Working Capital

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

Net cash flows from operating activities decreased by $86.2 million in 2010 as compared to 2009. This decrease includes the effect of the deconsolidation of Cal Dive in June 2009 (Note 3), the receipt of insurance proceeds associated with the settlement of our Hurricane Ike claims (Note 4), our increased internal utilization of vessels for developing our oil and gas properties in the first quarter of 2010, and a decrease in our working capital cash flows.

Investing Activities

Capital expenditures have consisted principally of the purchase or construction of dynamically positioned vessels, strategic acquisitions of select businesses, improvements to existing vessels, acquisition 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, 2011, 2010 and 2009 were as follows (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Capital expenditures:			
Contracting services	$(69,259)	$(65,949)	$(204,228)
Shelf contracting			(39,569)
Oil and gas	(119,614)	(84,554)	(137,168)
Production facilities	(30,896)	(56,269)	(42,408)
Contribution to equity investments	(2,699)	(8,253)	(1,657)
Distributions from equity investments, net(1)	3,965	10,539	6,742
Proceeds from insurance reimbursements		16,106	

Proceeds from sale of Cal Dive common stock	3,588		418,168
Reduction in cash from deconsolidation of Cal Dive			(112,995)
Proceeds from sale of properties (2)	31,000	6,894	23,717
Other, net	1,598	(70)	(6)
Net cash used in investing activities	(182,317)	(181,556)	(89,404)
Net cash provided by discontinued operations(3)			20,872
Net cash used in investing activities	$(182,317)	$(181,556)	$(68,532)

(1) Distributions from equity investments is net of undistributed equity earnings from our investments.
Gross distributions from our equity investments are detailed in Note 7.

(2) For additional information related to sales of properties, see Note 5.

(3) Amount for 2009 included the sale of Helix RDS for $25 million, see Note 1.

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Restricted Cash

We had restricted cash totaling $33.7 million at December 31, 2011 and $35.3 million at December 31, 2010, all of which was related to funds required to be escrowed to cover the future asset retirement obligations associated with our South Marsh Island Block 130 field. We have fully satisfied the requirements under the escrow agreement. We have used a small portion of these escrowed funds to pay for the initial reclamation activities at the South Marsh Island Block 130 field. Reclamation activities at the field will occur over many years and will be funded with these escrowed amounts. These amounts are reflected in other assets, net in the accompanying consolidated balance sheets.

Outlook

We anticipate capital expenditures in 2012 will total approximately $445 million. The estimates for these capital expenditures 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 capital expenditures given any prolonged economic downturn or inability to execute sales transactions related to our remaining non-core business assets, most notably all or a portion of our oil and gas business assets. We believe internally generated cash flow, 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 2012 initiatives.

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual cash obligations as of December 31, 2011 and the scheduled years in which the obligations are contractually due (in thousands):

	Total (1)	Less Than 1 year	1-3 Years	3-5 Years	More Than 5 Years
Convertible Senior Notes(2)	$ 300,000	$	$	$	$300,000
Senior Unsecured Notes	474,960			474,960	
Term Loan(3)	279,750	3,000	6,000	270,750	
Revolving Loans(4)					
MARAD debt	110,166	4,877	10,496	11,569	83,224
Interest related to long-term debt	413,956	76,365	150,255	83,396	103,940
Drilling and development costs	12,667	12,667			
Property and equipment	29,819	29,819			
Operating leases(5)	54,426	42,813	9,418	1,589	606
Total cash obligations	$1,675,744	$169,541	$176,169	$842,264	$487,770

(1) Excludes unsecured letters of credit outstanding at December 31, 2011 totaling $41.4 million. These letters of credit primarily guarantee asset retirement obligations as well as various contract bidding, insurance activities and shipyard commitments.

(2) Contractual maturity in 2025 (Notes can be redeemed by us or we may be required to purchase beginning in December 2012). Notes can be converted prior to stated maturity if the closing sales 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 120% of the closing price on that 30th trading day (i.e. $38.56 per share) and under certain triggering events as specified in the indenture governing the Convertible Senior Notes. To the extent we do not have alternative long-term financing secured to cover the conversion, the Convertible Senior Notes would be classified as a current liability in the accompanying balance sheet. As of December 31, 2011, the conversion trigger was not met.

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(3) Our Term Loan will mature on July 1, 2015 but may extend to July 1, 2016 if our Senior Unsecured Notes are either refinanced or repaid in full by July 1, 2015 (Note 9).

(4) 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 9).

(5) Operating leases include facility leases and vessel charter leases. Vessel charter lease commitments at December 31, 2011 were approximately $44.6 million.

Contingencies

Whenever we have a contract that qualifies as a loss contract, we estimate the future shortfall between our anticipated future revenues and future costs. We had one such contract in 2008, which was ultimately terminated because of the delay in the delivery of the Caesar. As of December 31, 2008, we estimated the loss under this contract at $9.0 million. In the second quarter of 2009, services under this contract were substantially completed by a third party and we revised our estimated loss to approximately $15.8 million. Subsequently, we settled the liability for $12.7 million. Accordingly, we included an additional $3.7 million of charges to cost of sales in the accompanying consolidated statements of operations for the year ended December 31, 2009. We paid $7.2 million of the loss in 2008 and the remaining $5.5 million in the second quarter of 2010.

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 our WOSEA subsidiary 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.

In 2006, 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 and claims 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,

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in 2010 we established an allowance against our trade receivable balance that reduces its balance to an amount we believe is ultimately realizable based on ongoing negotiations. 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 related to a subsea construction and diving contract we entered into in December 2006 in India for the tax years 2007, 2008, 2009, and 2010. 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 we believe that we have complied with all rules and regulations as relate 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.

See Item 3. Legal Proceedings and Notes 2 and 16 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). In early 2009, we recorded an aggregate of $53.4 million beneficial conversion charges related to our Convertible Preferred Stock. The holder has redeemed a total of $54 million of shares of our Convertible Preferred Stock with $1 million remaining outstanding at December 31, 2011. See Note 11 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. For a detailed discussion on the application of our accounting policies see Note 2.

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, particularly our subsea construction 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, 2011 and 2010 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.

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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. 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.

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. At December 31, 2010, we had one contract for a project that was deemed to be in loss status and we recorded an aggregate $30.0 million pre-tax charge to cost of sales related to the loss to completion of the contract (see "Contingencies above and Notes 2 and 16). We recognize additional contract revenue related to claims when the claim is probable and legally enforceable.

Oil and Gas Revenues

We record revenues from the sales of crude oil and natural gas when delivery to the customer has occurred, prices are fixed and determinable, collection is reasonably assured and title has transferred. This occurs when production has been delivered to a pipeline or a barge lifting has occurred. We may have an interest with other producers in certain properties. In this case, we use the entitlements method to account for sales of production. Under the entitlements method, we may receive more or less than our entitled share of production. If we receive more than our entitled share of production, the imbalance is treated as a liability. If we receive less than our entitled share, the imbalance is recorded as an asset. As of December 31, 2011, the net imbalance was a $0.9 million asset and was included in Other Current Assets ($5.1 million) and Accrued Liabilities ($4.2 million) in the accompanying consolidated balance sheet.

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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, 2011 we had two reporting units with goodwill and our impairment analysis.

In 2011, we adopted the new accounting standards intended 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. Early adoption is permitted, including for annual and interim goodwill impairment tests performed, if an entity's financial statements for the most recent annual or interim period have not yet been issued. The Company early adopted this standard for its annual goodwill impairment tests in 2011.

All of our remaining goodwill at December 31, 2011 ($62.2 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 1 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.

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 had been 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

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(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.

We did not record any impairment of goodwill in 2009 based on our evaluations conducted throughout the year.   We primarily focused our goodwill evaluations on our WOSEA reporting unit's goodwill as its results were adversely affected by damage to its main revenue generating asset. The asset repairs were substantially complete by December 31, 2009 and based on WOSEA's forecasted business activity no impairment of its goodwill was necessary during 2009. In 2010, WOSEA placed its revenue generating asset back in service and also entered into a joint venture in February 2010 (Note 7). Despite these positive developments, in 2010 WOSEA's operating results were disappointing and its near-term outlook also 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 1 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 2 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 was no goodwill impairment in 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, 2011, our principal non-U.S. subsidiaries had accumulated earnings and profits of approximately $113.4 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, 2011, 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 10 for discussion of net operating loss carry forwards, deferred income taxes and uncertain tax positions taken by us.

Accounting for Oil and Gas Properties

Acquisitions of producing offshore properties are recorded at the fair value exchanged at closing together with an estimate of their proportionate share of the asset retirement obligations assumed in the purchase (based upon working interest ownership percentage). In estimating the asset retirement obligations assumed in offshore property acquisitions, we perform detailed estimating procedures, including engineering studies, and then reflect the liability at fair value on a discounted basis as discussed below.

We follow the successful efforts method of accounting for our interests in oil and gas properties. Under the successful efforts 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. Capitalized costs of producing oil and gas properties are depleted to operations by the unit-of-production method based on proved developed oil and gas reserves on a field-by-field basis as determined by our engineers. Leasehold costs for producing properties are depleted using the units-of-production method based on the amount of total estimated proved reserves on a

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field-by-field basis. Costs incurred relating to unsuccessful exploratory wells are expensed in the period the drilling is determined to be unsuccessful (see "— Exploratory Drilling Costs" below).

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 "Oil and gas property impairments" 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—generally on a field-by-field basis for oil and gas assets. 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 flow 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 future production volumes, commodity prices, operating costs, project margins and capital project decisions, considering all available information at the date of review. The impairment review includes cash flows from proved developed and undeveloped reserves, including any development expenditures necessary to achieve that production. Additionally, when probable reserves exist, an appropriate risk-adjusted amount of these reserves may be included in the impairment calculation. We recorded property impairments totaling $132.6 million in 2011, $181.1 million in 2010 and $120.6 million in 2009, primarily related to downward reserve revisions, decreased natural gas prices, increased estimates of asset retirement obligations and weak end of life well performance in some of our properties.

We also periodically assess unproved properties for impairment based on exploration and drilling efforts to date on the individual prospects and lease expiration dates. 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 also impact the amounts and timing of impairment provisions. We recorded a total of $8.3 million in 2011, $6.4 million in 2010 and $20.1 million in 2009 of exploration expense to write off certain unproved oil and gas properties reflecting management's assessment that exploration activities would not commence prior to the respective lease expiration dates.

Exploratory Drilling Costs

In accordance with the successful efforts method of accounting, the costs of drilling an exploratory well are capitalized pending the determination of whether the well has found proved reserves. If proved reserves are not found, these capitalized costs are charged to exploration expense. A determination that proved reserves have been found results in the continued capitalization of the drilling costs of the well and its reclassification as a well containing proved reserves.

At times, it may be determined that an exploratory well may have found hydrocarbons at the time drilling is completed, but it may not be possible to classify the reserves at that time. In this case, we may continue to capitalize the drilling costs as a suspended well beyond one year when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project, or the reserves are deemed to be proved. If reserves are not ultimately deemed proved or economically viable, the well is considered impaired and its costs, net of any salvage value, are charged to expense. We did not write off any suspended well costs in 2011 or 2010 but did write off $0.5 million of such costs in 2009.

Estimated Proved Oil and Gas Reserves

The evaluation of our oil and gas reserves is critical to the management of our oil and gas operations. Decisions such as whether development of a property should proceed and what technical methods are available for development are based on an evaluation of reserves. Oil and gas reserve quantities are also used as the basis for calculating the unit-of-production rates for depreciation, depletion and amortization, evaluating impairment and estimating the life of our producing oil and gas properties in our asset retirement obligations. Our proved reserves are classified as either proved developed or proved undeveloped.

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Proved developed reserves are those reserves which can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves include reserves expected to be recovered from new wells, from undrilled proven reservoirs or from existing wells where a significant major expenditure is required for completion and production. All of the estimates of proved reserves in this Annual Report were prepared based on guidelines promulgated under generally accepted accounting principles in the United States. Our process for preparing reserve estimates is described in Item 2. Properties "— Summary of Oil and Natural Gas Reserve Data." Our estimated proved reserves in this Annual Report include only quantities that we expect to recover commercially using the average price for the last 12 months of any given year, costs, existing regulatory practices and technology. While we are reasonably certain that the estimated proved reserves will be produced, the timing and ultimate recovery can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and changes in projections of long-term oil and gas prices. Revisions can include upward or downward changes in the previously estimated volumes of proved reserves for existing fields due to evaluation of (1) already available geologic, reservoir or production data or (2) new geologic or reservoir data obtained from wells. Revisions can also include changes associated with significant changes in development strategy, oil and gas prices, or production equipment/facility capacity.

Accounting for Asset Retirement Obligations

Our asset retirement obligations consist of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. Our oil and gas operations personnel prepare detailed cost estimates to plug and abandon wells and remove necessary equipment in accordance with regulatory guidelines. We currently calculate the discounted value of the asset retirement obligation (based on an estimate of the year in which the abandonment will occur) and capitalize that portion as part of oil and gas properties and record the related abandonment liability. The recognition of an asset retirement obligation requires that management make numerous estimates, assumptions and judgments regarding factors such as the existence of a legal obligation or liability, estimated probabilities, amounts and timing of settlements, the credit-adjusted risk-free rate to be used, and inflation rates.

On an ongoing basis, our oil and gas operations personnel monitor the status of wells, and as fields deplete and no longer produce, our personnel will monitor the timing requirements set forth by the BOEM and BSEE for plugging and abandoning the wells and will commence abandonment operations when applicable. On an annual basis, management personnel review and update the abandonment estimates and assumptions for changes, among other things, in market conditions, interest rates and historical experience.

Derivative Instruments and Hedging Activities

Our risk management activities involve the use of derivative financial instruments to hedge the impact of market risk exposure primarily related to our oil and gas production 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. Hedge accounting does not apply to oil and gas forward sales contracts as these qualify for the normal purchase and sale scope exception. At December 31, 2011, we had no oil and gas forward contracts.

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 (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 (Note 20).

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.

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 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.

Property and Equipment

Property and equipment (excluding oil and gas properties 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 flow 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 2011, we recorded an asset impairment charge of $6.6 million to our subsea service equipment located 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. We had no assets that met the criteria of being classified as assets held for sale at December 31, 2011.

Equity Investments

We periodically review our investments in Deepwater Gateway, Independence Hub and the Australian joint venture 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

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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.   See Note 7 for information regarding a $10.6 million other than temporary impairment charge associated with our Australian joint venture.

Worker’s Compensation Claims

Our onshore employees are covered by Worker’s Compensation. Offshore employees, including divers, tenders and marine crews, are covered by our Maritime Employers Liability (“MEL”) insurance policy which covers Jones Act exposures. We incur workers’ compensation and MEL claims in the normal course of business, which management believes are substantially covered by insurance. Our insurers and legal counsel analyze each claim for potential exposure and estimate the ultimate liability of each claim. Actual liability can be materially different from our estimates and can have a direct impact on our liquidity and results of operations.

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

We are currently exposed to market risk in three major areas: interest rates, commodity prices and foreign currency exchange rates.

Interest Rate Risk. As of December 31, 2011, approximately 6.8% 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 January 2010 we entered into two-year cash flow hedging interest rate swaps to stabilize cash flows relating to interest payments on $200 million of our Term Loan. 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 contracts, which are settled monthly, begin 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 $1.5 million in interest expense for the year ended December 31, 2011.

Commodity Price Risk. We have utilized derivative financial instruments with respect to a portion of our 2011, 2010 and 2009 oil and gas production to achieve a more predictable cash flow. We do not enter into derivative or other financial instruments for trading purposes.

As of December 31, 2011, we had derivative contracts related to our oil and gas production totaling approximately 3.8 million barrels of oil and 17.0 Bcf of natural gas. At December 31, 2011, our existing contracts were as follows

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price a
Crude Oil:			(per barrel)
January 2012 — December 2012	Collar	75.0 MBbl	$ 96.67 — $118.57b
January 2012 — December 2012	Collar	139.0 MBbl	$ 99.42 — $117.59
January 2012 — December 2012	Swap	16.0 MBbl	$103.20
January 2013 — December 2013	Swap	41.7 MBbl	$99.15
January 2013 — December 2013	Collar	41.7 MBbl	$ 95.00 — $102.60

Natural Gas:			(per Mcf)
January 2012 — December 2012	Swaps	750.0 Mmcf	$4.35
January 2012 — December 2012	Collar	166.7 Mmcf	$4.75 — $5.09
January 2013 — December 2013	Swaps	500.0 Mmcf	$4.09

a. The prices quoted in the table above are NYMEX Henry Hub for natural gas. For oil most of the contracts are priced as Brent crude oil.
b. This contract is priced using NYMEX West Texas Intermediate for crude oil.

In February 2012, we entered into a costless collar financial derivative contract associated with a total of 0.1 MMBbls of our anticipated crude oil production in 2013, with a floor price of $100 per barrel and a ceiling price of $120 per barrel as indexed to Brent crude oil prices.

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Changes in NYMEX oil and gas strip prices would, assuming all other things being equal, cause the fair value of these instruments to increase or decrease inversely with the change in NYMEX prices.

Foreign Currency Exchange 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 WOUK and WOSEA). The functional currency for WOUK is the applicable local currency (British Pound). The functional currency for WOSEA is the applicable local currency (Australian Dollar). 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 in the shareholders' equity section of our balance sheet. At December 31, 2011, approximately 10% of our assets are impacted by changes in foreign currencies in relation to the U.S. dollar. We recorded unrealized gains (losses) of $(1.0) million, $(10.0) million and $30.6 million to accumulated other comprehensive income (loss) for the years ended December 31, 2011, 2010 and 2009, 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 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 they consider the 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 statements of operations as a component of other income (expense). These amounts resulted in a gains (loss) of $(1.6) million, $1.7 million and $2.2 million for the years ended December 31, 2011, 2010 and 2009, 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 flow 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 liability of $0.1 million as of December 31, 2011 and a net asset of $0.2 million at December 31, 2010. The gain (losses) resulting from changes in the fair value of our foreign currency forwards that were not designated for hedge accounting (Note 20) totaled $0.2 million, $(2.6) million and $3.3 million for the years ended December 31, 2011, 2010 and 2009, respectively.

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Item 8. Financial Statements and Supplementary Data.

INDEX TO FINANCIAL STATEMENTS

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, 2011, 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, 2011, 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, 2011, 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, 2011, 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, 2011 and 2010, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2011 and our report dated February 24, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 24, 2012

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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, 2011 and 2010, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2011. 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. 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) have been audited by other auditors whose reports have been furnished to us, and our opinion on the consolidated financial statements, insofar as it relates to the amounts included for Deepwater Gateway, L.L.C. and Independence Hub, LLC, is based solely on the reports of the other auditors. In the consolidated financial statements, the Company’s Equity investments includes approximately $176 million and $182 million from Deepwater Gateway, L.L.C. and Independence Hub, LLC combined at December 31, 2011 and 2010, respectively, and the Company’s Equity in earnings of investments includes approximately $20 million and $23 million for the years ended December 31, 2011 and 2010, respectively, from Deepwater Gateway, L.L.C. and Independence Hub, LLC combined.

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, 2011 and 2010, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 19 to the consolidated financial statements, in 2009 the Company changed its reserve estimates and required disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

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, 2011, 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 24, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 24, 2012

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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, 2011 and 2010, and the related statements of operations, cash flows and members' equity for each of the three years in the period ended December 31, 2011. 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 generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the auditing 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, 2011 and 2010, and the results of its operations and cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Houston, Texas
February 15, 2012

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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, 2011 and 2010, and the related statements of operations, cash flows, and members' equity for each of the three years in the period ended December 31, 2011. 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 generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the auditing 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, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Houston, Texas
February 15, 2012

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 546,465	$ 391,085
Accounts receivable —		
Trade, net of allowance for uncollectible accounts of $4,067 and $4,527	238,781	177,293
Unbilled revenue	24,338	33,712
Costs in excess of billing	13,037	15,699
Other current assets	121,621	123,065
Total current assets	944,242	740,854
Property and equipment	4,391,064	4,486,077
Less — Accumulated depreciation	(2,059,737)	(1,958,997)
	2,331,327	2,527,080
Other assets:		
Equity investments	175,656	187,031
Goodwill, net	62,215	62,494
Other assets, net	68,907	74,561
	$ 3,582,347	$ 3,592,020
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 147,043	$ 159,381
Accrued liabilities	239,963	198,237
Income tax payable	1,293	—
Current maturities of long-term debt	7,877	10,179
Total current liabilities	396,176	367,797
Long-term debt	1,147,444	1,347,753
Deferred income taxes	417,610	413,639
Asset retirement obligations	161,208	170,410
Other long-term liabilities	9,368	5,777
Total liabilities	2,131,806	2,305,376
Convertible preferred stock	1,000	1,000
Commitments and contingencies		
Shareholders' equity:		
Common stock, no par, 240,000 shares authorized, 105,530 and 105,592 shares issued	908,776	906,957
Retained earnings	522,644	392,705
Accumulated other comprehensive loss	(10,017)	(39,058)
Total controlling interest shareholders' equity	1,421,403	1,260,604
Noncontrolling interests	28,138	25,040
Total equity	1,449,541	1,285,644
	$ 3,582,347	$ 3,592,020

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

	Year Ended December 31,		
	2011	2010	2009
	(In thousands, except per share amounts)		
Net revenues:			
Contracting services	$ 702,000	$ 774,469	$ 1,076,349
Oil and gas	696,607	425,369	385,338
	1,398,607	1,199,838	1,461,687
Cost of sales:			
Contracting services	528,375	600,083	854,975
Oil and gas	396,123	376,724	218,617
Oil and gas property impairments	132,603	181,083	120,550
Exploration expense	10,914	8,276	24,383
	1,068,015	1,166,166	1,218,525
Gross profit	330,592	33,672	243,162
Goodwill impairments	—	(16,743)	—
Gain on oil and gas derivative commodity contracts	—	1,088	89,485
Gain on sale of assets, net	4,525	9,405	2,019
Selling, general and administrative expenses	(99,589)	(122,078)	(130,851)
Income (loss) from operations	235,528	(94,656)	203,815
Equity in earnings of investments	22,215	19,469	32,329
Other than temporary loss on equity investments	(10,563)	(2,240)	—
Gain on investment in Cal Dive common stock	753	—	77,343
Net interest expense	(95,796)	(85,303)	(56,733)
Other income (expense)	(4,157)	(1,021)	5,238
Income (loss) before income taxes	147,980	(163,751)	261,992
Provision (benefit) for income taxes	14,903	(39,598)	95,822
Income (loss) from continuing operations	133,077	(124,153)	166,170
Income from discontinued operations, net of tax	—	—	9,581
Net income (loss), including noncontrolling interests	133,077	(124,153)	175,751
Net income applicable to noncontrolling interests	(3,098)	(2,835)	(19,697)
Net income (loss) applicable to Helix	129,979	(126,988)	156,054
Preferred stock dividends	(40)	(114)	(748)
Preferred stock beneficial conversion charges	—	—	(53,439)
Net income (loss) applicable to Helix common shareholders	$ 129,939	$ (127,102)	$ 101,867
Basic earnings (loss) per share of common stock:			

Continuing operations	$	1.23	$	(1.22)	$	0.92
Discontinued operations		—		—		0.09
Net income (loss) per common share	$	1.23	$	(1.22)	$	1.01
Diluted earnings (loss) per share of common stock:						
Continuing operations	$	1.22	$	(1.22)	$	0.87
Discontinued operations		—		—		0.09
Net income (loss) per common share	$	1.22	$	(1.22)	$	0.96
Weighted average common shares outstanding:						
Basic		104,528		103,857		99,136
Diluted		104,953		103,857		105,720

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
(amounts 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, 2008	91,972	$ 806,905	$ 417,940	$ (33,696)	$ 1,191,149	$322,627	$ 1,513,776
Comprehensive income (loss)							
Net income	—	—	156,054	—	156,054	19,697	175,751
Effect of deconsolidation of Cal Dive (Note 3)	—	—	—	—	—	(320,119)	(320,119)
Foreign currency translations adjustments	—	—	—	30,617	30,617	—	30,617
Unrealized loss on hedges, net	—	—	—	(18,275)	(18,275)	—	(18,275)
Unrealized loss on investment held for sale (Note 2)	—	—	—	(887)	(887)	—	(887)
Comprehensive income (loss)					167,509	(300,422)	(132,913)
Convertible preferred stock dividends and preferred stock beneficial charges	—	—	(54,187)	—	(54,187)	—	(54,187)
Convertible preferred stock conversion (Note 11)	12,805	102,502	—	—	102,502	—	102,502
Other	—	(319)	—	—	(319)	—	(319)
Stock compensation expense	—	9,530	—	—	9,530	—	9,530
Stock repurchase	(1,116)	(13,995)	—	—	(13,995)	—	(13,995)
Activity in company stock plans, net	620	2,173	—	—	2,173	—	2,173

Excess tax benefit from stock-based compensation	—	895	—	—	895	—	895
Balance, December 31, 2009	104,281	$907,691	$ 519,807	$ (22,241)	$ 1,405,257	22,205	$1,427,462
Comprehensive income (loss)							
Net income	—	—	(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
Comprehensive income (loss)					(143,805)	2,835	(140,970)
Convertible preferred stock dividends and preferred stock beneficial charges	—	—	(114)	—	(114)	—	(114)
Convertible preferred stock conversion (Note 11)	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

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HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(Continued)
(amounts 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, 2010	105,592	$906,957	$ 392,705	$ (39,058)	$ 1,260,604	$ 25,040	$1,285,644
Comprehensive income (loss)							
Net income	—	—	129,979	—	129,979	3,098	133,077
Foreign currency translations adjustments	—	—	—	(1,002)	(1,002)	—	(1,002
Unrealized gain on hedges, net	—	—	—	30,043	30,043	—	30,043
Comprehensive income					159,020	3,098	162,118
Convertible preferred stock dividends and preferred stock beneficial charges	—	—	(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

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

	Year Ended December 31, 2011	2010	2009
	(In thousands)		
Cash flows from operating activities:			
Net income (loss), including noncontrolling interests	$ 133,077	$ (124,153)	$ 175,751
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by operating activities —			
Depreciation and amortization	311,103	317,116	262,617
Asset impairment charges	139,167	181,083	121,855
Goodwill and other indefinite-lived intangible impairments	—	16,743	—
Exploratory drilling and related expenditures	8,264	5,969	21,367
Equity in earnings of investments, net of distributions	—	—	(6,321)
Amortization of deferred financing costs	8,910	7,703	6,693
Income from discontinued operations	—	—	(9,581)
Stock compensation expense	8,365	8,996	11,992
Amortization of debt discount	8,973	8,409	7,880
Deferred income taxes	(4,188)	(46,836)	(64,926)
Excess tax benefit from stock-based compensation	1,013	3,945	(895)
Unrealized loss (gain) on derivative contracts	382	1,568	(5,237)
Loss on early extinguishment of Senior Unsecured Notes	2,354	—	—
Other than temporary loss on equity investments	10,563	2,240	—
Gain on investment in Cal Dive common stock	(753)	—	(77,343)
Gain on sale of assets	(4,525)	(9,405)	(2,019)
Changes in operating assets and liabilities:			
Accounts receivable, net	(47,998)	(46,191)	52,245
Other current assets	560	21,894	51,158
Income tax payable	6,472	214	48,831
Accounts payable and accrued liabilities	28,230	48,411	(62,341)
Oil and gas asset retirement costs	(41,980)	(61,763)	(45,038)
Other noncurrent, net	(833)	(4,489)	(62,750)
Cash provided by operating activities	567,156	331,454	423,938
Cash used in discontinued operations	—	—	(6,261)
Net cash provided by operating activities	567,156	331,454	417,677
Cash flows from investing activities:			
Capital expenditures	(219,769)	(206,772)	(423,373)
Investments in equity investments	(2,699)	(8,253)	(1,657)
Distributions from equity investments, net	3,965	10,539	6,742
Proceeds from insurance reimbursement	—	16,106	—
Proceeds from sale of Cal Dive common stock	3,588	—	418,168
Reduction in cash from deconsolidation of Cal Dive	—	—	(112,995)

Proceeds from sales of property		31,000		6,894		23,717
Decrease (increase) in restricted cash		1,598		(70)		(6)
Cash used in investing activities		(182,317)		(181,556)		(89,404)
Cash provided by discontinued operations		—		—		20,872
Net cash used in investing activities	$	(182,317)	$	(181,556)	$	(68,532)

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

	Years Ended December 31,		
	2011	2010	2009
	(in thousands)		
Cash flows from financing activities:			
Repayment of Helix term loan	$ (130,691)	$ (4,326)	$ (4,326)
Borrowings on Helix Revolver	109,400	—	—
Repayments on Helix Revolver	(109,400)	—	(349,500)
Early extinguishment of Senior Unsecured Notes	(77,394)	—	—
Repayment of MARAD borrowings	(4,645)	(4,424)	(4,214)
Borrowings on CDI Revolver	—	—	100,000
Repayments on CDI term loan	—	—	(20,000)
Loan notes repayment	(1,215)	(2,517)	(2,130)
Deferred financing costs	(9,311)	(2,947)	(6,970)
Preferred stock dividends paid	(40)	(114)	(645)
Repurchase of common stock	(7,604)	(11,680)	(13,995)
Excess tax benefit from stock-based compensation	(1,013)	(3,945)	895
Exercise of stock options, net	2,018	674	176
Net cash used in financing activities	(229,895)	(29,279)	(300,709)
Effect of exchange rate changes on cash and cash equivalents	436	(207)	(1,376)
Net increase in cash and cash equivalents	155,380	120,412	47,060
Cash and cash equivalents:			
Balance, beginning of year	391,085	270,673	223,613
Balance, end of year	$ 546,465	$ 391,085	$ 270,673

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 Report 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 3). We are an international offshore energy company that provides development solutions and other contracting services to the energy market as well as to our own oil and gas properties. Our Contracting Services segment utilizes our vessels, offshore equipment and proprietary technologies to deliver services that may reduce finding and development costs and cover the complete lifecycle of an offshore oil and gas field. Our Contracting Services are located primarily in the Gulf of Mexico, North Sea, Asia Pacific, and West Africa regions. Our Oil and Gas segment engages in prospect generation, exploration, development and production activities. Our oil and gas operations are located 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 operations, robotics, subsea construction and production facilities. We have disaggregated our contracting services operations into two continuing reportable business segments: Contracting Services and Production Facilities. Our Contracting Services business primarily consists of well operations, robotics and subsea construction activities. Formerly, we had a third Contracting Services business segment, Shelf Contracting, which represented the assets of CDI. We sold substantially all of our ownership of CDI through various transactions in 2009 (Note 3). Our Production Facilities business includes our equity investments in Deepwater Gateway, L.L.C. ("Deepwater Gateway") and Independence Hub, LLC ("Independence Hub") (Note 7), as well as our majority ownership of the Helix Producer I ("HP I") vessel.

Oil and Gas Operations

We began our oil and gas operations to achieve incremental returns, to expand our off-season asset utilization of our contracting services assets, and to provide a more efficient solution to offshore abandonment. We have evolved this business model to include not only mature oil and gas properties but also unproved and proved reserves yet to be explored and developed. This has led to the assembly of services that allows us to create value at key points in the life of a reservoir from exploration through development, life of field management and operating through abandonment.

Discontinued Operations

In April 2009, we sold Helix Energy Limited ("HEL"), our former reservoir technology consulting business, to a subsidiary of Baker Hughes Incorporated for $25 million. As a result of the sale of HEL, which entity's operations were conducted by its wholly owned subsidiary, Helix RDS Limited ("Helix RDS"), we have presented the results of Helix RDS as discontinued operations in the accompanying consolidated financial statements. HEL and Helix RDS were previously components of our Contracting Services segment. In 2009, we recognized an $8.3 million gain on the sale of HEL.

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Events in Gulf of Mexico

In April 2010, an explosion occurred on the Deepwater Horizon drilling rig located on the site of the Macondo well at Mississippi Canyon Block 252. The resulting events included loss of life, the complete destruction of the drilling rig, and an oil spill the magnitude of which was unprecedented in U.S. territorial waters. In May 2010, the U.S. Department of Interior ("DOI") announced a total moratorium on new drilling in the Gulf of Mexico. In October 2010, the DOI lifted the deepwater drilling moratorium and instructed the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE") that it could resume issuing drilling permits conditioned on the requesting company's compliance with all revised drilling, safety and environmental requirements. No post moratorium deepwater drilling permits were issued by BOEMRE until late February 2011. In October 2011, the BOEMRE separated into two new federal agencies, the Bureau of Ocean Energy Management ("BOEM") and Bureau of Safety and Environmental Management ("BSEE").

We developed the Helix Fast Response System ("HFRS") as a culmination of our experience as a responder in the Gulf oil spill response and containment efforts. The HFRS centers on two vessels, the HP I and the Q4000, both of which played a key role in the Gulf 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 for a two-year term 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. The retainer fee for the HFRS became effective April 1, 2011 and is a component of our Production Facilities business segment. A total of 55 permits have been granted to CGA participants for deepwater drilling operations identifying the HFRS to fulfill the BOERME (BOEM/BSEE) requirement to have a spill response and containment resource included in the submitted permit applications.

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 consolidated our former subsidiary CDI until June 10, 2009, at which time our ownership in CDI was reduced to less than 50%. We recorded our proportional share of CDI's results under the equity method of accounting until we sold substantially all of our ownership interest in CDI on September 23, 2009. We sold our remaining ownership interest in CDI in 2011. We also account for our Deepwater Gateway, Independence Hub and Australian joint venture investments under the equity method of accounting. Noncontrolling interests represent the minority shareholders' proportionate share of the equity in CDI until we deconsolidated its results in June 2009 and Kommandor LLC. All material intercompany accounts and transactions have been eliminated. Certain reclassifications were made to previously reported amounts in the consolidated financial statements and notes thereto to make them consistent with the current presentation format.

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.

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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

As of December 31, 2011 and 2010, we had $33.7 million and $35.3 million, respectively, of restricted cash included in other assets (Note 6), all of which related to funds required to be escrowed to cover the future asset retirement obligations associated with our South Marsh Island Block 130 field. We have fully satisfied the requirements under the escrow agreement. We have used a small portion of these escrowed funds to pay for the initial reclamation activities at the South Marsh Island Block 130 field. Reclamation activities at the field will occur over many years and will be funded with these escrowed amounts. These amounts are reflected in other assets, net in the accompanying consolidated balance sheets.

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

	Year Ended December 31,		
	2011	2010	2009
Interest paid, net of interest capitalized	$ 81,000	$ 68,534	$ 48,313
Income taxes paid	$ 11,216	$ 10,071	$ 106,480

Non-cash investing activities for the years ended December 31, 2011, 2010 and 2009 included $26.1 million, $21.9 million and $48.9 million, respectively, related to accruals of capital expenditures. The accruals have been reflected in the accompanying consolidated balance sheets as an increase in property and equipment and accounts payable.

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 18).

Inventories

We had inventory totaling $18.1 million at December 31, 2011 and $25.3 million at December 31, 2010. Our 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. These costs will be partially reimbursed by third party participants in the wells supplied with these materials. Our inventories are stated at the lower of cost or market value and we utilize the average cost method of maintaining our inventory. 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. This sale transaction closed in early January 2012. There were no charges to reduce inventory to its lower cost or market value in 2010. For the year ended December 31, 2009, we recorded an aggregate of $1.8 million of charges to cost of sales to reduce our inventory to its lower of cost or market value at various times throughout the year.

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Property and Equipment

Overview. Property and equipment is recorded at cost. The following is a summary of the gross components of property and equipment (dollars in thousands):

	Estimated Useful Life	2011	2010
ROVs/Vessels	10 to 30 years	$ 1,616,772	$ 1,573,471
Oil and gas leases and related equipment	Units-of-Production	2,574,693	2,747,895
Machinery, equipment, buildings and leasehold improvements	5 to 30 years	199,599	164,711
Total property and equipment		$ 4,391,064	$ 4,486,077

The cost of repairs and maintenance is charged to expense as incurred, while the cost of improvements is capitalized. Total repair and maintenance expenses totaled $40.1 million, $35.0 million and $35.6 million for the years ended December 31, 2011, 2010 and 2009, respectively. Included in machinery, equipment, buildings and leasehold improvements were $18.1 million and $17.8 million of capitalized software costs at December 31, 2011 and 2010, 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, 2011, 2010 and 2009.

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 flow 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 2011, in an acknowledgment of our declining operating results in Australia and in association with the reorganization of our Australian well operations business, 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. During 2009, we recorded an aggregate $1.3 million charge to reduce the carrying value of certain specific ROV equipment to its fair value of $6.1 million. There were no such impairments related to our vessels during 2011, 2010 and 2009. See Note 5 for disclosure related to the impairment of our 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, 2011 and 2010.

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

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accounting estimate. We depreciate our other property and equipment over its estimated useful life on a straight-line basis.

Oil and Gas Properties. All of our oil and gas properties are in the United States located offshore in the Gulf of Mexico. We follow 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 flow in the accompanying consolidated statements of cash flows. Costs incurred relating to unsuccessful exploratory wells are expensed in the period when the drilling is determined to be unsuccessful and are included as a reconciling item to net income (loss) in operating activities in the accompanying consolidated statements of cash flows.

Proved Properties. We assess proved oil and gas properties for possible impairment at least annually or when events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. We recognize an impairment loss 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 an impairment is indicated, the cash flows are discounted at an approximate rate that market participants would be willing to pay for similar types of assets and compared to the carrying value for determining the amount of the impairment loss to record. 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 Note 5 for additional information regarding our oil and gas property impairments.

Unproved Properties. We also periodically assess unproved properties for impairment based on exploration and drilling efforts to date on the individual prospects and lease expiration dates. 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 also impact the amounts and timing of impairment provisions. We recorded impairments to unproved oil and gas properties totaling \$8.3 million in 2011, \$6.4 million in 2010 and \$20.1 million in 2009. Such impairments were included in exploration expenses for our Oil and Gas business segment.

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 expense. At times, it may be determined that an exploratory well may have found hydrocarbons at the time drilling is completed, but it may not be possible to classify the reserves at that time. In this case, we may continue to capitalize the drilling costs as an uncompleted, or "suspended," well beyond one year if we can justify its completion as a producing well and we are making sufficient progress assessing the reserves and the economic and operating viability of the project. If reserves are not ultimately deemed proved or economically viable, the well is considered impaired and its costs, net of any salvage value, are charged to expense. See Note 5 for additional information regarding our exploration costs.

Properties Acquired from Business Combinations. Properties acquired through business combinations are recorded at their fair value. In determining the fair value of the proved and unproved properties, we prepare estimates of oil and gas reserves. We estimate future prices to apply to the estimated reserve quantities acquired and the estimated future operating and development costs to arrive at our estimates of future net revenues. For the fair value assigned to proved reserves, the future net revenues are discounted using a market-based weighted average cost of capital rate determined to be appropriate at the time of the acquisition. To compensate for inherent risks of estimating and valuing unproved reserves, probable and possible reserves are reduced by additional risk weighting factors.

Capitalized Interest. 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, 2011, 2010 and 2009 was $1.3 million, $12.5 million and $48.1 million, respectively.

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Equity Investments

We periodically review our equity investments in Deepwater Gateway, Independence Hub and our Australian joint venture 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. See Notes 3 and 9 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, 2011 we had two reporting units with goodwill and our impairment analysis.

In 2011, we adopted the new accounting standards intended 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. Early adoption is permitted, including for annual and interim goodwill impairment tests performed, if an entity’s financial statements for the most recent annual or interim period have not yet been issued. The Company early adopted this standard for its annual goodwill impairment tests in 2011.

All of our remaining goodwill at December 31, 2011 ($62.2 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 newly enacted accounting guidance to forego the historically mandated quantitative step 1 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.

Historically, 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

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reporting unit is allocated to all the assets and liabilities, including any unrecognized intangible assets, as if the reporting unit had been 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.

We did not record any impairment of goodwill in 2009 based on our evaluations conducted throughout the year. We primarily focused our goodwill evaluations on our Well Ops SEA Pty Ltd ("WOSEA") reporting unit's goodwill as its results were adversely affected by damage to its main revenue generating asset. The asset repairs were substantially complete at December 31, 2009 and based on WOSEA's then forecasted business activity no impairment of its goodwill was necessary during 2009. WOSEA placed its revenue generating asset back in service in 2010 and also entered into the an Australian joint venture in February 2010 (Note 7). 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 1 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 2 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 business segment.

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

	Contracting Services
Balance at December 31, 2009 (1)	$ 78,643
Impairments (2)	(16,743)
Other adjustments(3)	594
Balance at December 31, 2010	62,494
Impairments	—
Other adjustments(3)	(279)
Balance at December 31, 2011	$ 62,215

(1) Prior to 2009, we fully impaired our oil and gas related goodwill ($704.3 million) as well as the $8.3 million of goodwill associated with our former reservoir consulting business.
(2) Amount reflects full write off of goodwill associated with our WOSEA operations.
(3) Reflects foreign currency adjustment for certain amounts of our goodwill.

At December 31, 2011, our only remaining intangible asset, other than goodwill, was $1.6 million ($0.5 million, net of accumulated amortization) for intellectual property related to our well operations business in the North Sea. Total amortization expenses for intangible assets for the years ended December 31, 2011, 2010, and 2009 was $0.1 million, $0.1 million and $2.4 million, respectively. We expect to record a total of $0.1 million of amortization expense related to our remaining unamortized intellectual property for each of the next five years.

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Recertification Costs and Deferred Drydock 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 drydock. 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 drydock and related recertification costs over the length of time for which we expect to receive benefits from the drydock 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 drydock and related recertification processes. A drydock 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, 2011 and 2010, capitalized deferred drydock charges included within Other Assets in the accompanying consolidated balance sheets (Note 6) totaled $5.4 million and $11.1 million, respectively. During the years ended December 31, 2011, 2010 and 2009, drydock amortization expense was $7.6 million, $6.9 million and $16.4 million, respectively. Amounts attributed to Cal Dive's operations totaled $9.3 million for the period prior to its deconsolidation in June 2009.

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 consist of estimated costs for dismantlement, removal, site reclamation and similar activities associated with our 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 (both long term and current) for the years ended December 31, 2011 and 2010 (in thousands):

	2011	2010
Asset retirement obligations at January 1,	$ 234,936	$ 248,128
Liability incurred during the period	4,982	18,056
Liability settled during the period	(42,675)	(55,114)
Other revisions in estimated cash flows	42,268(1)	8,349
Accretion expense (included in depreciation and amortization)	14,880	15,517
Asset retirement obligations at December 31,	$ 254,391	$ 234,936

(1) Includes impairment charges totaling $41.7 million, including $20.0 million associated with our only United Kingdom oil and gas property, to increase the estimated asset retirement obligation related to properties that are no longer producing oil or natural gas.

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 Contracting Services contracts are contracts that contain either lump-sum, turnkey or other 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.

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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, 2011 and 2010 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 the 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 16 for information regarding our more significant loss contracts during the three years ended December 31, 2011.

Oil and Gas Revenues

We record revenues from the sales of crude oil and natural gas 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, we use the entitlements method to account for sales of production. Under the entitlements method, we may receive more or less than our entitled share of production. If we receive more than our entitled share of production, the imbalance is treated as a liability. If we receive less than our entitled share, the imbalance is recorded as an asset. As of December 31, 2011, the net imbalance was a $0.9 million asset and was included in Other Current Assets ($5.1 million) and Accrued Liabilities ($4.2 million) in the accompanying consolidated balance sheet.

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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 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, 2011, 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

The functional currency for our foreign subsidiary, Helix Well Ops (U.K.) Limited is the applicable local currency (British Pound), and the functional currency of WOSEA is the applicable local currency (Australian Dollar). 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, 2011 and 2010 and the resulting translation adjustment, which was an unrealized losses of $1.0 million and $10.0 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 $(1.6) million in 2011, $1.7 million in 2010 and $2.2 million in 2009. These realized amounts are exclusive of any unrealized gains or losses from our foreign currency exchange derivative contracts.

Derivative Instruments and Hedging Activities

We are currently exposed to market risk in three major areas: commodity price, interest and foreign currency exchange rates. Our risk management activities involve the use of derivative financial instruments to hedge the impact of market risk exposure primarily related to our oil and gas production prices, variable interest rates and foreign currency exchange rates. All derivatives are reflected in our balance sheet at fair value, unless otherwise noted.

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, 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.

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, the 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

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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 are amortized to earnings over the remaining period of the original forecasted transaction.

Commodity Price Risks

The fair value of 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. Our actual results may differ from our estimates, and these differences can be positive or negative.

Historically, we have entered into various financial derivative contracts, including costless collar and swap contracts, to stabilize cash flows relating to a portion of our expected oil and gas production. At December 31, 2008, our commodity derivative contracts continue to qualify for hedge accounting. However, the effects of the hurricane damage sustained in the third quarter of 2008 continued to disrupt our production causing most of our 2009 natural gas financial contracts to no longer qualified for hedge accounting as of March 31, 2009. At their inception, our forward sales contracts qualified for the normal purchases and sales scope exception but due to disruptions in our production as a result of damage caused by the 2008 hurricanes these contracts ceased to qualify for the scope exception at March 31, 2009. As previously noted, contracts that fail to qualify for hedge accounting must be marked-to-market each reporting period.

At December 31, 2009, all the then existing commodity derivative contracts qualified for hedge accounting. In June 2010, oil contracts for 480 MBbl of our anticipated production during the third quarter of 2010 ceased to qualify for hedge accounting as a result of our decision to contract the HP I to assist in the Gulf oil spill response and containment efforts rather than commencing production from our Phoenix field. In September 2010, we concluded that oil contracts covering 480 MBbls of the fourth quarter 2010 anticipated production ceased to qualify for hedge accounting because of uncertainty as to when the Phoenix field would be ready to commence initial production following extensions of the HP I contract to assist BP in the oil spill response and containment efforts. The HP I returned to the Phoenix field in October and initial production from the field commenced on October 19, 2010. At December 31, 2011, all of our existing commodity derivative contracts qualified for hedge accounting treatment.

The aggregate fair value of our commodity derivative instruments represented a net asset of $19.8 million at December 31, 2011 and a net liability of $24.4 million at December 31, 2010. For the years ended December 31, 2011, 2010 and 2009, we recorded unrealized gains (losses) of approximately $28.7 million, $(6.5) million and $(19.1) million, respectively, net of taxes (benefit) of $15.5 million, $(3.5) million and $(10.3) million, respectively, in accumulated other comprehensive income (loss). During 2011, 2010 and 2009, we reclassified approximately $(21.7) million, $25.6 million and $17.0 million, respectively, of gains (losses) from accumulated other comprehensive income (loss) to oil and gas revenues upon the sale of the related oil and gas production. In addition, during 2010 and 2009 we recorded gains of approximately $1.1 million and $89.5 million, respectively, to reflect mark-to-market adjustments for changes in the fair values of our contracts that no longer qualified for hedge accounting. These gains are reported in the accompanying consolidated statements of operations in the line titled "Gain on oil and gas derivative commodity contracts". There were no mark-to-market adjustments during 2011 associated with our commodity derivative contracts. The amount of ineffectiveness related to our oil and gas commodity contracts was immaterial for all periods presented in this Annual Report on Form 10-K. See Note 20 for more disclosure regarding our hedge contracts.

As of December 31, 2011, we had derivatives contracts related to our oil and gas production totaling approximately 3.8 million barrels of oil and 17 Bcf of natural gas. At December 31, 2011 our derivative commodity contracts were as follows:

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Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price a
Crude Oil:			(per barrel)
January 2012 — December 2012	Collar	75.0 MBbl	$ 96.67 — $118.57b
January 2012 — December 2012	Collar	139.0 MBbl	$ 99.42 — $117.59
January 2012 — December 2012	Swap	16.0 MBbl	$103.20
January 2013 — December 2013	Swap	41.7 MBbl	$99.15
January 2013 — December 2013	Collar	41.7 MBbl	$ 95.00 — $102.60
Natural Gas:			(per Mcf)
January 2012 — December 2012	Swaps	750.0 Mmcf	$4.35
January 2012 — December 2012	Collar	166.7 Mmcf	$4.75 — $5.09
January 2013 — December 2013	Swaps	500.0 Mmcf	$4.09

a. The prices quoted in the table above are NYMEX Henry Hub for natural gas. For oil most of the contracts are priced as Brent crude oil.

b. This contract is priced using NYMEX West Texas Intermediate for crude oil.

In February 2012, we entered into a costless collar financial derivative contract associated with a total of 0.1 MMBbls of our anticipated crude oil production in 2013, with a floor price of $100 per barrel and a ceiling price of $120 per barrel as indexed to Brent crude oil prices.

Changes in NYMEX oil and gas strip prices would, assuming all other things being equal, cause the fair value of these instruments to increase or decrease inversely with the change in NYMEX prices.

Variable Interest Rate Risks

As the interest rates for some of our long-term debt are subject to market influences and will vary over the term of the debt, we entered into various interest rate swaps to stabilize cash flows relating to a portion of our interest payments on our variable interest rate debt. Changes in the interest rate swap fair value are deferred to the extent the swap is effective and are recorded as a component of accumulated other comprehensive income until the anticipated interest payments occur and are recognized in interest expense. The ineffective portion of the interest rate swap, if any, will be recognized immediately in earnings. Ineffectiveness related to our interest swaps was immaterial for all periods presented in this Annual Report on Form 10-K.

In January 2010, we entered into $200 million two-year interest rate swaps to stabilize cash flows relating to a portion of our interest payments on our Term Loan, which extended through January 2012 (Note 9). 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 contracts settle monthly beginning in January 2012 and extend through January 2014. The fair value of our remaining interest swap contracts was a net asset of $0.1 million at December 31, 2011 and a net liability of $1.9 million at December 31, 2010 (Note 20).

Foreign Currency Exchange Risks

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 liability of $0.1 million at December 31, 2011 and a net asset of $0.2 million at December 31, 2010. 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 $0.2 million in 2011, $(2.6) million in 2010 and $3.3 million in 2009 associated with foreign exchange contracts not qualifying for hedge accounting. See Note 20 for more information regarding our foreign currency contracts.

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Earnings Per Share

We have shares of restricted stock issued and outstanding, which are subject to certain 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 available to 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 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, 2011, 2010 and 2009 are as follows (in thousands):

	Year Ended December 31,					
	2011		2010		2009	
	Income	Shares	Income	Shares	Income	Shares
Basic:						
Net income (loss) applicable to common shareholders	$129,939		$(127,102)		$101,867	
Less: Undistributed net income allocable to participating securities	(1,599)				(1,436)	
Undistributed net income (loss) applicable to common shareholders	128,340		(127,102)		100,431	
(Income) loss from discontinued operations					(9,581)	
Add: Undiscounted net income from discontinued operations allocable to participating securities					135	
Income (loss) per common share – continuing operations	$128,340	104,528	$(127,102)	103,857	$ 90,985	99,136

	Year Ended December 31,					
	2011		2010		2009	
	Income	Shares	Income	Shares	Income	Shares
Diluted:						
Net income (loss) per common share – continuing operations – Basic	$128,340	104,528	$(127,102)	103,857	$ 90,985	99,136

Effect of dilutive securities:						
Stock options		64				28
Undistributed earnings reallocated to participating securities	7				80	
Convertible Senior Notes						
Convertible preferred stock	40	361			748	6,556
Income (loss) per common share continuing operations	128,387		(127,102)		91,813	
Income (loss) per common share discontinued operations					9,581	
Net income (loss) per common share	$128,387	104,953	$(127,102)	103,857	$101,394	105,720

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The cumulative $53.4 million of beneficial conversion charges that were realized and recorded during the first quarter of 2009 following the transactions affecting our convertible preferred stock (Note 11) are not included as an addition to adjust earnings applicable to common stock for our diluted EPS calculation.

We had a net loss applicable to common shareholders for the year ended December 31, 2010. Accordingly, our diluted EPS calculation for 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 each of the year ended December 31, 2010, assuming we had earnings from continuing operations, are as follows (in thousands):

	2010
Diluted shares (as reported)	103,857
Stock options	54
Convertible preferred stock	1,015
Total	104,926

The diluted EPS calculation during the year ended December 31, 2010 also excluded the consideration of adding back the $0.1 million of 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 diluted during the year.

There were no dilutive shares associated with our 3.25% Convertible Senior Notes as the conversion price of $32.14 was not met in any of the years ended December 31, 2011, 2010 and 2009 (Note 9).

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 of major customers, those whose total represented 10% or more of our consolidated revenues, was as follows: 2011 — Shell (49%); 2010 — Shell (29%) and BP Plc. (17%) and 2009 —Shell (19%). These customers were primarily purchasers of our oil and gas production. We estimate that in 2011 we provided subsea services to over 75 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 noted. The valuation techniques are as follows:

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(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 value 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 and our long-term debt. 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, 2011 (in thousands):

	Level 1	Level 2 (1)	Level 3	Total	Valuation Technique
Assets:					
Oil and gas swaps and collars	$ –	$ 22,381	$ –	$ 22,381	(c)
Interest rate swaps	–	327	–	327	(c)
Foreign currency forwards	–	55	–	55	(c)
Liabilities:					
Oil and gas swaps and collars	–	2,597	–	2,597	(c)
Interest rate swaps	–	202	–	202	(c)
Foreign currency forwards	–	159	–	159	(c)
Fair value of long term debt (2)	1,081,376	124,488	–	1,205,864	(a)
Total net liability	$1,081,376	$104,683	$ –	$1,186,059	

(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. Where quotes are not available, we utilize other valuation techniques or models to estimate market values. These modeling techniques require us to use published future market prices and estimate market volatility and liquidity based on market data. Our actual results may differ from our estimates, and these differences can be positive or negative.

(2) See Note 9 for additional information regarding our long term debt. The fair value of our debt at December 31, 2011 and December 31, 2010 is as follows:

	2011		2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Term Loan(1)	$ 279,750	$ 279,750	$ 410,441	$ 406,337
Revolving Credit Facility				
Convertible Senior Notes(1) (2)	300,000	300,543	300,000	289,158
Senior Unsecured Notes(1)	474,960	501,083	550,000	567,875
MARAD Debt(3)	110,166	124,488	114,811	122,159
Loan Notes			1,208	1,208

Total	$ 1,164,876	$ 1,205,864	$ 1,376,460	$ 1,386,737

(1) The fair values of these instruments were based on quoted market prices as of December 31, 2011 and 2010. The fair values were estimated using level 1 inputs using the market approach.

(2) Carrying amounts exclude the $9.6 million and $18.5 million of unamortized discount on the Convertible Senior Notes at December 31, 2011 and 2010, respectively.

(3) The fair value of the MARAD debt was determined by a third-party evaluation of the remaining average life and outstanding principal balance of the MARAD indebtedness as compared to other government guaranteed obligations in the market place with similar terms. The fair value of the MARAD debt was estimated using Level 2 fair value inputs using the market approach.

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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 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.

In 2011, we recorded impairment charges totaling $132.6 million, including $20.0 million related to our one U.K oil and gas property. These impairment charges affected the carrying value for 27 of our oil and gas fields in the Gulf of Mexico. These impairment charges reduced each field's carrying value to its then estimated fair value, which was $60.6 million following the respective impairment charges. In 2010, we recorded impairment charges totaling $181.1 million, including $5.0 million related to our one U.K oil and gas property. These impairment charges affected 28 of our Gulf of Mexico oil and gas properties. The estimated aggregate fair value of these 28 fields was $91.5 million following each field's respective impairment charge. In 2009, we recorded a total of $120.6 million of impairment charges, including the $51.5 million of hurricane-related impairments (Note 4). These impairment charges affected the carrying value of 47 of our Gulf of Mexico oil and gas fields. The aggregate fair value of these 47 fields was $36.2 million following each respective field's impairment charge. See Notes 5 and 21 for additional information regarding our oil and gas impairment charges, including impairment charges to increase the value of non-producing properties' estimated asset retirement obligations.

Debt Discount

On January 1, 2009, we recorded a discount of $60.2 million related to our Convertible Senior Notes as required under a newly-effective accounting pronouncement. To arrive at this discount amount we estimated the fair value of the liability component of the Convertible Senior 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. In selecting the expected life, we selected the earliest date that the holder could require us to repurchase all or a portion of the Convertible Senior Notes (December 15, 2012). The remaining unamortized amount of the discount of the Convertible Notes was $9.6 million at December 31, 2011 (Note 9).

Note 3 — Ownership of Cal Dive International, Inc.

Our ownership in CDI as of December 31, 2008 was approximately 57.2%. In January 2009, we sold approximately 13.6 million shares of Cal Dive common stock to Cal Dive for $86 million. This transaction constituted a single transaction and was not part of any planned set of transactions that would result in us having a noncontrolling interest in Cal Dive, and reduced our ownership in Cal Dive to approximately 51%. Because we retained control of CDI immediately after the transaction, the loss of approximately $2.9 million on this sale was treated as a reduction of our equity in the accompanying consolidated balance sheet.

In June 2009, we sold 22.6 million shares of Cal Dive common stock held by us pursuant to a secondary public offering ("Offering"). Proceeds from the Offering totaled approximately $182.9 million, net of underwriting fees. Simultaneously with the closing of the Offering, pursuant to a Stock Repurchase Agreement with Cal Dive, Cal Dive repurchased from us approximately 1.6 million shares of its common stock for net proceeds of $14 million at $8.50 per share, the Offering price. Following the closing of these two transactions, our ownership of Cal Dive common stock was reduced to approximately 26%.

Because these transactions reduced our ownership in Cal Dive to less than 50%, the $59.4 million gain resulting from the sale of these shares was reflected in

"Gain on investment in Cal Dive common stock" in the accompanying consolidated statement of operations. The $59.4 million amount included an approximate $27.1 million gain associated with the re-measurement of our remaining 26% ownership interest in Cal Dive at its fair value on June 10, 2009, the date of the closing of the Offering, which represented the date of deconsolidation. Since we no longer held a controlling interest in Cal Dive, we ceased consolidating Cal Dive effective June 10, 2009, and subsequently accounted for our remaining ownership interest in Cal Dive under the equity method of accounting until September 23, 2009, as further discussed below.

On September 23, 2009, we sold 20.6 million shares of Cal Dive common stock held by us pursuant to a second secondary public offering ("Second Offering"). On September 24, 2009, the underwriters sold an additional 2.6 million shares of Cal Dive common stock held by us pursuant to their overallotment option under the terms of the Second Offering. The price for the Second Offering was $10 per share, with resulting proceeds totaling approximately $221.5 million, net of underwriting fees. We recorded an approximate $17.9 million gain associated with the Second Offering transactions.

Following the closing of the Second Offering 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 at December 31, 2010. 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 the closing of the Second Offering. Our investment in Cal Dive was $2.8 million at December 31, 2010. 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.

Proceeds from our Cal Dive stock sale transactions were used for general corporate purposes.

Note 4 – Insurance Matters

In September 2008, we sustained damage to certain of our facilities resulting from Hurricane Ike. All of our business segments were affected by the hurricane; however, the oil and gas segment suffered the substantial majority of our damage. While we sustained damage to our own production facilities from Hurricane Ike, the larger issue in terms of our production recovery involved damage to third party pipelines and onshore processing facilities. The timing of the repairs of these facilities was not subject to our control. One significant third party pipeline was not repaired and placed back into service until January 2010. Our insurance policy, which covered all of our operated and non-operated producing and non-producing properties, was subject to an approximate $6 million aggregate deductible. We met our $6 million aggregate deductible in September 2008. We record our hurricane-related repair costs as incurred in cost of sales. We record insurance reimbursements when the realization of the claim for recovery of a loss is deemed probable. We did not have any material hurricane-related repair cost in the year ended December 31, 2011. For the years ending December 31, 2010 and 2009 we incurred $4.7 million and $25.8 million, respectively, of hurricane-related repair costs related to our oil and gas assets.

In June 2009, we reached a settlement with the underwriters of our insurance policies related to damage from Hurricane Ike. Insurance proceeds received in the second quarter of 2009 totaled $102.6 million. In the second quarter of 2009, we recorded a $43.0 million net reduction in our cost of sales representing the amount by which our insurance recoveries exceeded our costs during the second quarter of 2009. The cost reduction reflected the net proceeds of $102.6 million partially offset by $8.1 million of hurricane-related expenses incurred in the second quarter of 2009 and $51.5 million of hurricane-related impairment charges, including $43.8 million of additional estimated asset retirement costs resulting from additional work performed and/or further evaluation of facilities on properties that were classified as a “total loss” following the storm. In 2011, we received $5.0 million of supplemental insurance reimbursements.

Our insurance year runs from July 1 to June 30. Since 2009 our insurance renewals have not included wind storm coverage as the premium and deductibles have been relatively substantial for the coverage provided. In order to mitigate potential loss with respect to our most significant oil and gas

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properties from hurricanes in the Gulf of Mexico, we entered into a Catastrophic Bond instrument. The Catastrophic Bond provides for payments of negotiated amounts should an eye of a Category 2 or Category 3 or greater hurricane pass within specific pre-defined areas encompassing our more prominent oil and gas producing fields. The Catastrophic Bond is not considered a risk management instrument for accounting purposes. Accordingly, the payment associated with the Catastrophic Bond is not charged to expense on a straight line basis as is customary with insurance premiums, but rather it is charged to expense on a basis to reflect the Catastrophic Bond's intrinsic value at the end of the period. Because our Catastrophic Bond was underwritten to mitigate the risk of hurricanes in the Gulf of Mexico, substantially all of its intrinsic value is for the period associated with the "hurricane season" (typically June 1 to November 30) with a substantial majority of the intrinsic value associated with the period July 1 to September 30. The insurance expense associated with the Catastrophic Bond payment is recorded as lease operating expense a component of cost of sales for our oil and gas operations.

In June 2011, 2010 and 2009 we made our hurricane catastrophic bond payment associated with each upcoming insurance period. The payments were $10.6 million in June 2011, $11.9 million in June 2010 and $13.1 million in June 2009. The insurance expense charges recorded in each of the respective third quarter periods to reduce the value of our hurricane catastrophic bond to its intrinsic value at September 30th totaled $8.4 million in 2011, $9.4 million in 2010 and $10.4 million in 2009. For each of the respective fourth quarter periods the respective insurance charges totaled $2.0 million in 2011, $2.3 million in 2010 and $2.4 million in 2009.

Note 5 — Oil and Gas Properties

We follow the successful efforts method of accounting for our interests in oil and gas properties. Under the successful efforts 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. Costs incurred relating to unsuccessful exploratory wells are expensed in the period the drilling is determined to be unsuccessful.

At December 31, 2011, we had capitalized costs associated with ongoing exploration and/or appraisal activities totaling $5.8 million. These capitalized costs may be charged against earnings in future periods if management determines that commercial quantities of hydrocarbons have not been discovered or that future appraisal drilling or development activities are not likely to occur. The following table provides a detail of our capitalized exploratory project costs at December 31, 2011 and 2010 (in thousands):

	2011	2010
Wang (1)	$ 3,096	$ 3,095
Danny 2 (1)	2,619	32
Other	125	125
Total	$ 5,840	$ 3,252

(1) Amounts primarily reflect pre-engineering costs. The Wang prospect is located in proximity of our Phoenix field that commenced production in October 2010. The Danny 2 (formerly Kathleen) prospect is located within our Bushwood field at Garden Banks Blocks 462, 463, 506 and 507. Both Wang and Danny 2 are budgeted exploration capital expenditures for 2012.

The following table reflects net changes in exploratory well costs during the years ended December 31, 2011, 2010 and 2009 (in thousands):

	2011	2010	2009

Beginning balance at January 1,	$ 3,252	$ 3,059	$ 2,105
Additions pending the determination of proved reserves	2,513	(944)	36,208
Reclassifications to proved properties	5	713	(34,622)
Charged to dry hole expense	70	424	(632)
Ending balance at December 31,	$ 5,840	$ 3,252	$ 3,059

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Further, the following table details the components of exploration expense for the years ended December 31, 2011, 2010 and 2009 (in thousands):

	Years Ended December 31, 2011	2010	2009
Delay rental and geological and geophysical costs	$ 2,650	$ 2,306	$ 3,016
Impairment of unproved properties	8,334	6,394	20,130
Dry hole expense	(70)	(424)	1,237
Total exploration expense	$ 10,914	$ 8,276	$ 24,383

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 Revenues. Royalty fees paid totaled approximately $85.4 million, $37.2 million and $26.8 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Gulf of Mexico Acquisitions and Dispositions.

In August 2006, we acquired a 100% working interest in the Typhoon oil field (Green Canyon Blocks 236/237), the Boris oil field (Green Canyon Block 282) and the Little Burn oil field (Green Canyon Block 238) in exchange for the assumption of certain asset retirement obligations. We renamed this field “Phoenix”. We sold a 30% working interest in these fields to a third party in 2007 for $40 million. Production was re-established from the Phoenix field on October 19, 2010. The Little Burn oil field commenced production in August 2011.

In the first quarter of 2009, we sold our interest in East Cameron Block 316 for gross proceeds of approximately $18 million. In the second quarter of 2009, we sold three fields for gross proceeds of $0.8 million resulting in an aggregate gain of $1.2 million, including the transfer of the fields’ asset retirement obligations.

In 2009, we farmed-out our 100% leasehold interests in Green Canyon Block 490 located in the deepwater of the Gulf of Mexico. Our farm out agreement was structured such that the operator paid 100% of the drilling costs to evaluate the prospective reservoir. The operator drilled a successful exploration well and we subsequently elected to participate for a 25 percent working interest in the field. Well completion and development commenced in 2011. In December 2011, we sold our ownership interest in this field for gross proceeds of approximately $31 million and recorded a pre-tax gain of $4.5 million. The transaction is also subject to certain customary closing conditions, which will result in the receipt of additional proceeds for capital expenditures we paid subsequent to the sale transaction effective date.

Royalty Claims

We and other industry participants were involved in a dispute with the U.S. Department of the Interior Minerals Management Service (“MMS”), predecessor of the BOEMRE and more recently the BOEM and BSEE, over royalties associated with production from certain deepwater oil and gas leases. As a result of this dispute, we recorded reserves for the disputed royalties (and any other royalties that may be claimed for production during 2005, 2006, 2007 and 2008) plus interest at 5% for our portion the MMS claim, which affected our Garden Banks Blocks 667, 668 and 669 (“Gunnison”) leases. The result of accruing these reserves since 2005 reduced our oil and gas revenues. In the first quarter of 2009, following the decision of the United States Court of Appeals for the Fifth Circuit Court affirming the district court’s previous ruling in favor of the plaintiffs in that case, which pertained to the Gunnison leases, we reversed our previously accrued royalties ($73.5 million) to oil and gas revenues. On October 5, 2009, the United

States Supreme Court denied the government's petition for a writ of certiorari, and the MMS subsequently withdrew its orders to pay the royalty.

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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. The following table contains the fair value of the assets acquired and liabilities assumed in our acquisition of this third party and its 50% working interest in the Camelot field (in thousands):

Cash	$ 10,156
Deferred tax asset	2,083
Accrued liabilities	(439)
Asset retirement obligation	(5,841)
Gain on acquisition of assets	$ 5,959

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. We recorded $5.0 million of total impairment charges to fully impair the property in 2010.

Our plan is to fully abandon the field in 2012 in accordance with applicable regulations in the United Kingdom. Modifications to U.K regulations over 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 that needs to be performed in the abandoning of the wells in the field would be significantly expanded and as a result our cost estimates have significantly increased. Based on our abandonment plan for 2012, we increased the asset retirement obligation by $20.0 million in 2011, which is reflected as a component of our impairment of oil and gas properties in the accompanying consolidated statements of operations. At December 31, 2011, the recorded asset retirement obligation for the Camelot field was $27.3 million.

Impairments

Proved property impairment charges are reflected as reductions in cost of sales in the accompanying consolidated statements of operations. However, because of the materiality of our oil and gas property impairment charges we reflect these as a separate line item within cost of sales in the accompanying consolidated statements of operations.

In 2011, we recorded $132.6 million of oil and gas property impairment charges, including $20.0 million related to our one U.K oil and gas property (see “United Kingdom Property” above). The $112.6 million of impairment charges associated with 27 of our Gulf of Mexico oil and gas fields included $21.7 million related to increasing the estimated asset retirement obligation for fields that are no longer producing. The impairment charges associated with producing fields totaled $90.9 million and were primarily related to changes in the related 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 $181.1 million of oil and gas property impairment charges, including $5.0 million related to our one U.K. oil and gas property. A total of 28 of our Gulf of Mexico oil and gas properties were affected by impairments charges in 2010. The impairment charges associated with producing fields totaled $172.6 million, which primarily reflected reduction in our estimated proved reserves (Note 19). We also recorded $3.5 million of impairment charges to increase certain non-producing field's estimated asset retirement obligations.

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In 2009, we recorded $120.6 million of oil and gas property impairment charges. We impaired a total of 47 of our Gulf of Mexico oil and gas properties. The impairment charges associated with producing fields totaled $72.4 million, which reflected decreases in estimated proved reserves associated with mechanical and production issues at certain fields. We also recorded $48.2 million of impairment charges to increase certain fields estimated asset retirement obligations, including $43.8 million of impairment related charges recorded to properties that were severely damaged by Hurricane Ike (Note 4).

Note 6 — Details of Certain Accounts (in thousands)

Other current assets consisted of the following as of December 31, 2011 and 2010:

	2011	2010
Other receivables	$ 5,096	$ 1,247
Prepaid insurance	12,701	12,375
Other prepaids	13,271	11,623
Spare parts inventory	18,066	25,333
Current deferred tax assets	41,449	49,200
Hedging assets	21,579	5,472
Income tax receivable	—	6,099
Gas and oil imbalance	5,134	6,001
Other	4,325	5,715
	$ 121,621	$ 123,065

Other assets, net, consisted of the following as of December 31, 2011 and 2010:

	2011	2010
Restricted cash	$ 33,741	$ 35,339
Deferred drydock costs, net	5,381	11,086
Deferred financing costs, net	26,483	25,697
Intangible assets with finite lives	531	636
Other	2,771	1,803
	$ 68,907	$ 74,561

Accrued liabilities consisted of the following as of December 31, 2011 and 2010:

	2011	2010
Accrued payroll and related benefits	$ 49,599	$ 38,026
Royalties payable	19,391	15,008
Current asset retirement obligations	93,183	64,526
Unearned revenue	7,654	1,817
Billings in excess of costs	28,839	6,146
Accrued interest	24,028	27,308
Hedging liability	1,247	30,606
Gas and oil imbalance	4,177	770

Other	11,845	14,030
	$ 239,963	$ 198,237

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Note 7 — Equity Investments

In June 2002, we formed Deepwater Gateway with Enterprise Products Partners, L.P., in which we each own a 50% interest, to design, construct, install, own and operate a tension leg platform ("TLP") production hub in deepwater of the Gulf of Mexico. Deepwater Gateway primarily services the Marco Polo field, which is owned and operated by Anadarko Petroleum Corporation. Our share of the Deepwater Gateway construction costs was approximately $120 million and our investment totaled $96.0 million and $99.8 million as of December 31, 2011 and 2010, respectively, and was included in our Production Facilities business segment. The investment balance at December 31, 2011 and 2010 included approximately $1.4 million and $1.5 million, respectively, of capitalized interest and insurance paid by us.

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. First production began in July 2007. Our investment in Independence Hub was $79.7 million and $82.4 million as of December 31, 2011 and 2010, respectively (including capitalized interest of $4.9 million and $5.2 million at December 31, 2011 and 2010, respectively), and was included in our Production Facilities business segment.

We made the following contributions to our equity investments during the years ended December 31, 2011, 2010 and 2009 (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Clough Helix Pty Ltd. (see below)	$ 2,699	$ 8,253	$ —
Other	—	—	1,657
Total	$ 2,699	$ 8,253	$ 1,657

We received the following distributions from our equity investments during the years ended December 31, 2011, 2010 and 2009 (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Deepwater Gateway	$ 7,600	$ 8,125	$ 6,750
Independence Hub	18,580	21,615	26,000
Other	—	268	—
Total	$ 26,180	$ 30,008	$ 32,750

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 vessel that is under charter to the joint venture until November 2013. 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; while 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 SapuraCrest Petroleum Berhad ("Sapura"). Sapura acquired Clough's 50% ownership interest in the joint venture in this transaction. The joint venture is continuing; however, there is now considerable uncertainty on whether the term of the joint venture will continue subsequent to the expiration of the original charter of the Normand Clough in November 2013. Separately, at December 31, 2011, the limited backlog of work indicated that earnings and resulting cash flow from the joint venture was at best expected to break even during 2012. Because of these indicators, we conducted an impairment assessment of our investment in the joint venture. 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

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other than temporary impairment charge in the accompanying consolidated statements of operations.

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

	Year Ended December 31,		
	2011	2010	2009
Revenues	$193,521	$141,705	$ 141,664
Operating income	97,954	93,324	118,566
Net income	93,215	93,005	118,602

	At December 31,		
	2011	2010	2009
Current assets	$ 39,754	$ 25,352	$ 18,620
Total assets	591,761	594,645	602,413
Current liabilities	11,012	6,434	415
Total liabilities	27,163	19,695	734

(1) Results do not include any amounts associated with Cal Dive. We accounted for our investment in Cal Dive under the equity method from June 10, 2009 to September 23, 2009 (Note 3).

Note 8 — 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 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 our Phoenix field, in which we hold a 70% working interest. 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 Gulf oil spill response 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 on October 19, 2010.

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 $196.2 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 the cash outlay to Kommandor RØMØ for its interest in Kommandor LLC at the time the put or call is exercised to 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, 2011.

Note 9 — Long-Term Debt

Senior Unsecured Notes

On December 21, 2007, we issued $550 million of 9.5% Senior Unsecured Notes due January 2016 (“Senior Unsecured Notes”). The Senior Unsecured Notes are fully and unconditionally guaranteed by substantially all of our existing restricted domestic subsidiaries, except Cal Dive I-Title XI, Inc. In addition, any future guarantor of our or any of our restricted subsidiaries’ indebtedness is also required to guarantee the Senior Unsecured Notes. Our foreign subsidiaries are not guarantors of the Senior Unsecured Notes. We used the proceeds from the Senior Unsecured Notes to repay outstanding indebtedness under our Senior Credit Facilities (see below).

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 existing and future senior unsecured indebtedness of the Company. The Senior Unsecured Notes rank senior in right of payment to any of our future subordinated indebtedness and are fully and unconditionally guaranteed by the guarantors described above on a senior basis.

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.

Included in the Senior Unsecured Notes indenture are terms, conditions and covenants that are customary for this type of offering. 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, 2011, we were in compliance with these covenants.

Prior to the stated maturity, after January 15, 2012, we may redeem all or a portion of the Senior Unsecured Notes, on not less than 30 days’ nor 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) 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.

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 the $75.0 million in principal and $2.4 million in premium for the repurchased Senior Unsecured Notes. The premium is reflected as a component of “other income (expense)” in the accompanying consolidated statements of operations. 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 original issuance of the Senior Unsecured Notes.

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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") and were initially able to borrow up to $300 million (the "Revolving Loans") under a revolving credit facility (the "Revolving Credit Facility"). The proceeds from the Term Loan were used to fund the cash portion of the acquisition of Remington Oil and Gas Corporation. At December 31, 2011, the total borrowing capacity under the Revolving Credit Facility totaled $600 million. The full amount of the Revolving Credit Facility may be used for issuances of letters of credit. At December 31, 2011 we had no amounts drawn on the Revolving Credit Facility and our availability under the Facility totaled $558.6 million, net of $41.4 million of unsecured letters of credit issued.

The Term Loan bears interest either at the one-, three- or six-month LIBOR at our current election plus a 2.00% margin (as amended in February 2010, the margin was increased up to 2.50% depending on current leverage ratios, as defined). Our average interest rate on the Term Loan for the years December 31, 2011 and 2010 was approximately 3.8% and 2.9%, respectively (including the effects of our interest rate swaps). The Revolving Loans bear interest based on one-, three- or six-month LIBOR rates or on Base Rates at our current election plus an applicable margin as discussed below. Margins on the Revolving Loans will fluctuate in relation to the consolidated leverage ratio as provided in the Credit Agreement. The average interest rate on the Revolving Loans was approximately 3.4% through the date of their repayment in the second quarter of 2009. We had no amounts outstanding under the revolver at any time during the year ended December 31, 2010.

We have amended the Credit Agreement three times over the past three years with the most recent amendment being effective in June 2011. These amendments among other things:

- Increase the Revolving Credit Facility to $600 million (capacity was $435 million prior to closing of the June 2011 amendment);

- provided for the repayment of $109.4 million of the outstanding principal portion of the Term Loan together with accrued interest thereon and related costs;

- extend the maturity date of the Term Loan from July 1, 2013 to a maturity date that is the earlier of (A) July 1, 2016, or (B), if our currently outstanding Senior Unsecured Notes due in 2016 are not fully re-financed or repaid by July 1, 2015, July 1, 2015;

- extend the maturity date of the Revolving Credit Facility from November 30, 2012 to a maturity date that is the earlier of (A) January 1, 2016, or (B), if our currently outstanding Senior Unsecured Notes due in 2016 are not fully re-financed or repaid by July 1, 2015, July 1, 2015;

- relax limitations on our right to dispose of certain Contracting Services assets comprising collateral under the Credit Agreement;

- permit us to repurchase or redeem all or part of our Convertible Senior Notes or Senior Unsecured Notes assuming certain conditions are met pro forma for any such transaction, including maintaining minimum levels of liquidity (defined as cash on hand and availability under our Revolving Credit Facility) of (A) $400 million with respect to the Convertible Senior Notes, and (B) $500 million with respect to the Senior Unsecured Notes; and

· increase the amount of restricted payments in the form of stock repurchases or redemptions that we are permitted to repurchase or redeem up to $50 million

· amend the consolidated leverage ratio (the ratio is now 4.00 to 1.00).

· add a Senior Credit Facility leverage ratio, which is now 2.00 to 1.00

· increase the margin on Revolving Loans by 0.50% should the consolidated leverage ratio equal or exceed 4.50 to 1.00 and increases the margin on the Term Loan by 0.25% if consolidated leverage ratio is less than 4.50 to 1.00 and 0.50% if the consolidated leverage ratio is equal to or greater than 4.50 to 1.00.

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- permit the disposition of certain oil and gas properties without a limit as to value, provided that we use 60% of the proceeds from such sales to make certain mandatory prepayments of the Term Loan (40% of the proceeds can be reinvested into collateral);

- relax limitations on our right to dispose of the Caesar vessel, by permitting the disposition of the Caesar provided that we use 60% of the proceeds from such sale to make certain mandatory prepayments of the Term Loan and permit us to contribute the Caesar to a joint venture or similar arrangement (40% of the proceeds can be reinvested into collateral); and

- increase the maximum amount of all investments permitted in subsidiaries that are neither loan parties nor whose equity interests are pledged from $100 million to $200 million.

We may elect to prepay amounts outstanding under the Term Loan 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 equal to the amount of proceeds received from such occurrences. Such prepayments will be applied first to the Term Loan, and any remaining excess will then be applied to the Revolving Loans.

The Credit Agreement and the other documents (together, the "Loan Documents") include terms, conditions and covenants that we consider customary for this type of transaction. 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 events of default that are customary for this type of transaction. As of December 31, 2011, 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 the Company. 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.

As the rates for our Term Loan are subject to market influences and will vary over the term of the credit agreement, we entered into various cash flow hedging interest rate swaps to stabilize cash flows relating to a portion of our interest payments for our Term Loan. In January 2010, we entered into $200 million, two-year interest rate swaps to stabilize cash flows relating to a portion of our interest payments on our Term Loan, which extend to January 2012. In August 2011, we entered into additional two-year interest rate swap contracts to assist in stabilizing cash flows related to our interest payment though January 2014 (Note 20).

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Convertible Senior Notes

In March 2005, we issued $300 million of 3.25% Convertible Senior Notes due 2025 (“Convertible Senior Notes”) at 100% of the principal amount to certain qualified institutional buyers. The Convertible Senior Notes are convertible into cash and, if applicable, shares of our common stock based on the specified conversion rate, subject to adjustment. As a result of our two for one stock split in December 2005, the initial conversion rate of the Convertible Senior Notes of 15.56 shares of common stock per $1,000 principal amount of the Convertible Senior Notes, which was equivalent to a conversion price of approximately $64.27 per share of common stock, was changed to 31.12 shares of common stock per $1,000 principal amount of the Convertible Senior Notes, which is equivalent to a conversion price of approximately $32.14 per share of common stock. We may redeem the Convertible Senior Notes on or after December 20, 2012. Beginning with the period commencing on December 20, 2012 to June 14, 2013 and for each six-month period thereafter, in addition to the stated interest rate of 3.25% per annum, we will pay contingent interest of 0.25% of the market value of the Convertible Senior Notes if, during specified testing periods, the average trading price of the Convertible Senior Notes exceeds 120% or more of the principal value. In addition, holders of the Convertible Senior Notes may require us to repurchase the notes at 100% of the principal amount on each of December 15, 2012, 2015, and 2020, and upon certain events, including a change of control (as defined) or the termination of trading of our common stock on a listed exchange. The effective interest rate for the Convertible Senior Notes was 6.6% following the adoption of accounting requirements as of January 1, 2009 (Note 2).

The Convertible Senior Notes can be converted prior to the stated maturity under the following circumstances:

- during any fiscal quarter if the closing sale price of our common stock for at least 20 trading days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter exceeds 120% of the conversion price on that 30th trading day (i.e., $38.56 per share);
- upon the occurrence of specified corporate transactions; or
- if we have called the Convertible Senior Notes for redemption and the redemption has not yet occurred.

To the extent we do not have alternative long-term financing secured to cover such conversion notice, the Convertible Senior Notes would be classified as a current liability in the accompanying consolidated balance sheet. As the holders have the option to require us to redeem the Convertible Senior Notes on December 15, 2012, we assessed whether or not this debt was required to be classified as a current liability at December 31, 2011 and concluded this debt still qualified as a long term debt because a) we possess enough borrowing capacity under our Revolving Credit Facility (see “Credit Agreement” above) to settle the notes in full and b) it is our intent to utilize our Revolving Credit Facility borrowings or other alternative financing proceeds to settle our Convertible Senior Notes, if and when the holders exercise their redemption option.

In connection with any conversion, we will satisfy our obligation to convert the Convertible Senior Notes by delivering to holders in respect of each $1,000 aggregate principal amount of notes being converted a “settlement amount” consisting of:

- cash equal to the lesser of $1,000 and the conversion value; and
- to the extent the conversion value exceeds $1,000, a number of shares equal to the quotient of (A) the conversion value less $1,000, divided by (B) the last reported sale price of our common stock for such day.

The conversion value means the product of (1) the conversion rate in effect (plus any applicable additional shares resulting from an adjustment to the conversion rate) or, if the Convertible Senior Notes are converted during a registration default, 103% of such conversion rate (and any such additional shares), and (2) the average of the last reported sale prices of our common stock for the trading days during the cash settlement period. At December 31, 2011, the conversion trigger was not met.

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Our weighted average share price for both 2011 and 2010 was below the conversion price of $32.14 per share. The maximum number of shares of common stock which may be issued upon conversion of the Convertible Senior Notes is 13,303,770. We registered the 13,303,770 shares of common stock that may be issued upon conversion of the Convertible Senior Notes as well as an indeterminate number of shares of common stock issuable upon conversion of the Convertible Senior Notes by means of an antidilution adjustment of the conversion price pursuant to the terms of the Convertible Senior Notes.

MARAD Debt

At December 31, 2011 and 2010, $110.2 million and $114.8 million, respectively, was outstanding on our long-term financing used for construction of the Q4000 ("MARAD Debt"). This U.S. Government guaranteed financing is pursuant to Title XI of the Merchant Marine Act of 1936 which is administered by the Maritime Administration. The MARAD Debt is payable in equal semi-annual installments which began 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, 2011, we were in compliance with these debt covenants.

Other

We paid financing costs associated with our debt totaling $9.3 million in 2011 and $2.9 million in 2010. Deferred financing costs of $26.5 million and $25.7 million at December 31, 2011 and 2010, respectively, are included within the caption "Other Assets, Net" in the accompanying consolidated balance sheets and are being amortized over the life of the respective debt agreements.

Scheduled maturities of long-term debt as of December 31, 2011 are as follows (in thousands):

	Helix Term Loan	Helix Revolving Loans	Senior Unsecured Notes	Convertible Senior Notes(1)	MARAD Debt	Total
Less than one year	$ 3,000	$	$	$	$ 4,877	$ 7,877
One to two years	3,000				5,120	8,120
Two to three years	3,000				5,376	8,376
Three to four years	270,750				5,644	276,394
Four to five years			474,960		5,925	480,885
Over five years				300,000	83,224	383,224
Total debt	279,750		474,960	300,000	110,166	1,164,876
Current maturities	(3,000)				(4,877)	(7,877)

Long-term debt, less current maturities	276,750		474,960	300,000	105,289	1,156,999
Unamortized debt Discount				(9,555)	—	(9,555)
Long-term debt	$276,750	$	$ 474,960	$ 290,445	$ 105,289	$ 1,147,444

(1) Beginning in December 2012, we may at our option repurchase the notes or the holders may require us to repurchase the notes. The notes will increase to the $300 million face amount through accretion of non-cash interest charges through December 2012.

We had unsecured letters of credit outstanding at December 31, 2011 totaling approximately $41.4 million. These letters of credit primarily guarantee various contract bidding, asset retirement obligations and insurance activities. The following table details our interest expense and capitalized interest for the years ended December 31, 2011, 2010 and 2009 (in thousands):

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	Year Ended December 31,		
	2011	2010	2009
Interest expense	$99,152	$ 99,184	$105,775
Interest income	(2,079)	(1,407)	(923)
Capitalized interest	(1,277)	(12,474)	(48,119)
Interest expense, net	$95,796	$ 85,303	$ 56,733

Note 10 — 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 conduct our international operations in a number of locations that have varying laws and regulations with regard to taxes. Management believes that adequate provisions have been made for all taxes that will ultimately be payable. 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 were as follows:

	Year Ended December 31,		
	2011	2010	2009
Statutory rate	35.0 %	35.0 %	35.0 %
Foreign provision	(2.0)	(4.3)	(1.1)
Effect of Australian reorganization	(21.2)		
IRC Section 199 deduction			(1.2)
CDI equity pick up in excess of tax basis			3.0
Nondeductible goodwill impairment (Note 2)		(4.4)	
Valuation allowance on certain deferred tax assets		(3.1)	
Other	(1.7)	1.0	0.9
Effective rate	10.1 %	24.2 %	36.6 %

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.

Components of the provision (benefit) for income taxes reflected in the statements of operations consisted of the following (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Current	$ 16,306	$ 7,238	$160,829
Deferred	(1,403)	(46,836)	(65,007)
	$ 14,903	$ (39,598)	$ 95,822
Domestic	$ 119	$ (57,165)	$ 94,388
Foreign	14,784	17,567	1,434

	$ 14,903	$ (39,598)	$ 95,822

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, 2011 and 2010 were as follows (in thousands):

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	2011	2010
Deferred tax liabilities:		
Depreciation and depletion	$ 396,355	$ 384,313
OID on Convertible Notes	37,067	34,169
Equity investments in production facilities	76,911	69,495
Prepaid and other	14,779	15,616
Total deferred tax liabilities	$ 525,112	$ 503,593
Deferred tax assets:		
Net operating loss carryforward	$ (34,987)	$ (38,718)
Asset retirement obligations	(88,279)	(81,345)
Reserves, accrued liabilities and other	(39,995)	(27,588)
Total deferred tax assets	$(163,261)	$(147,651)
Valuation allowance	14,310	8,497
Net deferred tax liability	$ 376,161	$ 364,439
Deferred income tax is presented as:		
Current deferred tax asset	$ (41,449)	$ (49,200)
Noncurrent deferred tax liabilities	417,610	413,639
Net deferred tax liability	$ 376,161	$ 364,439

At December 31, 2011, our federal net operating loss carryforward totaled $17.6 million and our foreign tax credit carryforward totaled $9.7 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, 2011, we had a $14.3 million valuation allowance related to certain non-U.S. deferred 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, 2011 and 2010, our principal non-U.S. subsidiaries had accumulated earnings and profits of approximately $113.4 million and $28.2 million, respectively. We have not provided deferred U.S. income tax on the accumulated earnings and profits.

We have $7.1 million related to uncertain tax positions, of which $0.9 million is accrued interest and penalties. We account for tax related interest in interest expense and tax penalties in operating expenses. During 2011, we recorded a $2.8 million long term liability related to an uncertain tax position and a $0.2 million long term liability for interest and penalties. As of December 31, 2011, 2010, and 2009 there were $6.2 million, $3.4 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):

	2011	2010	2009

Balance at January 1,	$	4,085	$	3,417	$	5,183
Additions based on tax positions related to current year		2,785				
Additions for tax positions of prior years		215		668		773
Reductions for tax positions of prior years						(2,539)
Balance at December 31,	$	7,085	$	4,085	$	3,417

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, 2006,

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2007, 2008 and 2009 are under examination by the U.S. Internal Revenue Service ("IRS"). The tax periods ended December 31, 2010 and 2011 remain open to future review and examination by the IRS. In non-U.S. jurisdictions, the open tax periods include 2007, 2008, 2009, 2010 and 2011.

Note 11 — Convertible Preferred Stock

In January 2009, Fletcher International, Ltd. ("Fletcher") issued a redemption notice with respect to its $30 million of Series A-2 Cumulative Convertible Preferred Stock and, pursuant to the resulting redemption, we issued and delivered 5,938,776 shares of our common stock to Fletcher. Accordingly, in the first quarter of 2009 we recognized a $29.3 million charge to reflect the terms of this redemption, which was recorded as a reduction in our net income applicable to common shareholders. This beneficial conversion charge reflected the value associated with the additional 3,974,718 shares delivered in connection with the redemption over the original 1,964,058 shares that would have been contractually required to be issued upon a conversion but was limited to the $29.3 million of net proceeds we received from the issuance of the Series A-2 Cumulative Convertible Preferred Stock in June 2004.

In February 2009, the price of our common stock fell below $2.767 per share. Under the terms of the agreement governing the issuance of the preferred stock, we provided notice to Fletcher that with respect to the $25 million of Series A-1 Cumulative Convertible Preferred Stock the conversion price was reset to $2.767, the established minimum price per the agreement; that Fletcher shall have no further rights to redeem the shares; and that we have no further right to pay dividends in common stock. As a result of the reset of the conversion price, Fletcher would receive an aggregate of 9,035,056 shares in future conversion(s) into our common stock. In the event we elected to settle any future conversion in cash, Fletcher would receive cash in an amount approximately equal to the value of the shares it would receive upon a conversion, which could be substantially greater than the original face amount of the Series A-1 Cumulative Convertible Preferred Stock, and which would result in additional beneficial conversion charges in our statement of operations. Under the existing terms of our Credit Agreement (Note 9) we are not permitted to deliver cash upon a conversion of the Convertible Preferred Stock.

In connection with the reset of the conversion price of the Series A-1 Cumulative Convertible Preferred Stock to $2.767, we were required to recognize a $24.1 million charge to reflect the value associated with the additional 7,368,388 shares that will be required to be delivered upon any future conversion(s) over the 1,666,668 shares that were to be delivered under the original contractual terms. This $24.1 million charge was recorded as a beneficial conversion charge reducing our net income applicable to common shareholders. The beneficial conversion charge for the Series A-1 Cumulative Convertible Preferred Stock was limited to the $24.1 million of net proceeds received upon its issuance in January 2003.

In the third quarter of 2009, Fletcher converted $19 million of its Series A-1 Cumulative Convertible Preferred Stock into 6,866,641 shares of our common stock. In May 2010, Fletcher converted $5 million of its Series A-1 Cumulative Convertible Preferred Stock into 1,807,011 shares of our common stock. The remaining $1 million of the Series A-1 Cumulative Convertible Preferred Stock, which is convertible into 361,402 shares of our common stock, maintains its mezzanine presentation below liabilities but is not included as a component of shareholders' equity, because we may, under certain instances, be required to settle any future conversions in cash. Prior to any future conversion(s), the common shares issuable will be assessed for inclusion in our diluted earnings per share computations using the if converted method based on the applicable conversion price of $2.767 per share, meaning that for all periods in which we have positive earnings from continuing operations and our average stock price exceeds $2.767 per share we will have an assumed conversion of convertible preferred stock and the 361,402 shares will be included in our diluted shares outstanding amount. At December 31, 2010, the $1 million of Convertible Preferred Stock outstanding was excluded from our diluted earnings per share calculation because we had a loss from continuing operations (Note 2).

The preferred stock has a minimum annual dividend rate of 4%, subject to adjustment, payable quarterly in cash. The dividend rate was 4% in 2011, 2010 and 2009. We paid these dividends in cash.

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Note 12 — 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 50 percent of each employee's contribution up to five percent of the employee's salary. Our costs related to deferred compensation plans totaled $1.4 million, $1.6 million and $1.5 million for the years ended December 31, 2011, 2010 and 2009, 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 (the "2005 Incentive Plan"). As of December 31, 2011, there were approximately 920,748 shares available for grant under our 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 key executives and selected employees and non-employee members of the 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. The aggregate number of shares that may be granted under the 2005 Incentive Plan is 6,000,000 shares (after adjustment for the December 2005 two-for-one stock split) of which 4,000,000 shares may be granted in the form of restricted stock or restricted stock units and 2,000,000 shares may be granted in the form of 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. For awards granted in 2012 under the Incentive Plans the vesting period is now three years or 33% per year. Stock options granted have a maximum exercise life of ten years. At December 31, 2011, all stock options outstanding had previously vested.

We use the Black-Scholes option pricing model for valuing share-based payments relating to stock options and recognize compensation cost on a straight-line basis over the applicable vesting period. Forfeitures on restricted stock totaled approximately 17% 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. We did not grant any stock options in 2011, 2010 or 2009. 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 options outstanding at December 31, 2011, have exercise prices as follows: 98,000 at $8.57; 14,000 shares at $10.59; 28,000 at $10.92 and 52,800 shares at $13.91 and a weighted average remaining contractual life of 1.4 years.

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Options outstanding are as follows:

	2011		2010		2009	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Options outstanding at beginning of year	432,918	$10.78	501,318	$10.74	521,654	$10.66
Exercised	(181,670)	$10.92	(68,400)	$10.52	(20,336)	$8.67
Terminated	(58,448)	$11.20	—	—	—	—
Options outstanding at end of year	192,800	$10.52	432,918	$10.78	501,318	$10.74
Options exercisable end of year	192,800	$10.52	432,918	$10.78	501,318	$10.74

There was no compensation recognized associated with stock options in 2011 or 2010 as all stock options outstanding are vested. For the year ended December 31, 2009, $0.1 million was recognized as compensation expense related to stock options. The aggregate intrinsic value of the stock options exercised in 2011, 2010 and 2009 was approximately $1.1 million, $0.1 million and $0.1 million, respectively. The aggregate intrinsic value of options exercisable at December 31, 2011, 2010 and 2009 was approximately $1.0 million, $0.6 million and $0.5 million, respectively.

Restricted Shares

We grant restricted shares to members of our board of directors, all executive officers and selected management employees. Compensation cost for each award is the product of grant date market value of each share and the number of shares granted. The following table summarizes information about our restricted shares during the years ended December 31, 2011, 2010 and 2009:

	2011		2010		2009	
	Shares	Grant Date Fair Value(1)	Shares	Grant Date Fair Value(1)	Shares	Grant Date Fair Value(1)
Restricted shares outstanding at beginning of year	1,463,298	$ 16.93	1,443,265	$ 21.55	1,206,526	$ 31.73
Granted	571,163	$ 12.77	599,996	$ 12.01	656,887	$ 7.12
Vested	(504,813)	$ 19.87	(444,905)	$ 25.10	(327,777)	$ 33.69
Forfeited	(266,430)	$ 12.55	(135,058)	$ 17.48	(92,371)	$ 8.90
Restricted shares outstanding at end of year	1,263,218	$ 14.80	1,463,298	$ 16.93	1,443,265	$ 21.55

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

For the years ended December 31, 2011, 2010 and 2009, $8.4 million, $9.0 million, $9.4 million, respectively, was recognized as compensation expense related to restricted shares. Future compensation cost associated with unvested restricted stock awards at December 31, 2011, 2010, and 2009 totaled approximately $23.4 million, $29.7 million and $21.8 million, respectively. The weighted average vesting period related to nonvested restricted stock awards at December 31, 2011 was approximately 2.7 years.

In January 2012, we granted our executive officers 132,910 restricted shares under the 2005 Long-Term Incentive Plan. The market value of the restricted shares was $15.80 per share or $2.1 million and the shares vest 33% per year for a three-year period. Separately, we issued our executive officers 132,910 performance share units ("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.

In January 2012, we also granted selected management employees 139,243 restricted stock units ("RSUs") 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. The market value of these RSUs was $15.80 per share or $2.2 million and will vest 33% per year for a three-year period.

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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.

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 terms of the 2009 LTI Plan, the cash awards that have been granted to non-executive management vest over a five-year period of employment and are made in a fixed sum amount. There were no cash awards to non-executive officers in 2011. Our executive officers are granted cash awards in which the amount of the payment on each applicable payment anniversary date (five-year term for awards granted prior to the January 2012 grant, which has a three-year term) will fluctuate based upon the Company's stock performance. 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. 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 50% (75% for 2012 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. The share-based component of our 2009 LTI Plan is considered a liability plan and as such will be re-measured to fair value each reporting period with corresponding changes be recorded as a charge to income as appropriate. At December 31, 2011 the liability under this stock-based liability plan was $8.5 million. We paid $4.0 million of this liability on January 3, 2012.

The awards made under the 2009 LTI Plan totaled $5.2 million to our executive officers in 2011, $10.2 million, including $6.0 million to our executive officers in 2010 and $14.7 million, including $8.1 million for our Executive Officers in 2009. For the years ended December 31, 2011, 2010 and 2009, $7.9 million ($6.5 million related to our executive officers), $8.6 million ($6.9 million related to our executive officers) and $3.7 million ($2.6 million related to executive officers), respectively, was recognized as compensation expense related to the 2009 LTI Plan. In January 2012, $4.2 million was awarded under the 2009 LTI Plan to our executive officers. No cash awards were given to non-executive employees.

Note 13 — 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, 2011 and 2010 were as follows (in thousands):

	2011	2010
Cumulative foreign currency translation adjustment	$ (22,958)	$ (21,956)

Unrealized losses on hedges, net (1)	12,941	(17,102)
Accumulated other comprehensive loss	$ (10,017)	$ (39,058)

(1) Amounts are net of deferred income tax asset (liabilities) totaling $7.0 million and $(9.2) million at December 31, 2011 and 2010, respectively.

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Note 14 — 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 12) as permitted under our Credit Agreement (Note 9). 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 early October 2011, we purchased the remaining 497,412 shares then available under this plan for $6.5 million or an average of $13.07 per share. As of December 31, 2011, we had repurchased a total of 2,473,730 shares of our common stock for $30.5 million or an average of $12.34 per share. We retire all repurchased shares.

Note 15 — Related Party Transactions

In April 2000, we acquired a 20% working interest in Gunnison, a Deepwater Gulf of Mexico prospect of Kerr-McGee. Financing for the exploratory costs of approximately $20 million was provided by an investment partnership (OKCD Investments, Ltd. or “OKCD”), the investors of which include certain current and former Helix senior management, in exchange for a revenue interest that is an overriding royalty interest of 25% of Helix’s 20% working interest. Production from the Gunnison field commenced in December 2003. We have made payments to OKCD totaling $8.3 million, $11.2 million and $11.3 million in the years ended December 31, 2011, 2010 and 2009 respectively. Our Chief Executive Officer, Owen Kratz, through Class A limited partnership interests in OKCD, personally owns approximately 80.7% of the partnership. In 2000, OKCD also awarded Class B revenue interests 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 $3.6 million for services provided to us in 2011. During 2010 and 2009, while this individual was still a member of our board of directors, we paid $6.9 million and $3.3 million, respectively, to Weatherford, an oil and gas industry company, for services provided to us.

Note 16 — Commitments and Contingencies

Lease Commitments

We lease several facilities, ROVs and vessels under noncancelable operating leases. Future minimum rentals under these leases are approximately $54.4 million at December 31, 2011 with $42.8 million due in 2012, $7.6 million in 2013, $1.8 million in 2014, $1.2 million in 2015, $0.4 million in 2016 and $0.6 million thereafter. Total rental expense under these operating leases was approximately $62.2 million, $66.2 million and $89.9 million for the years ended December 31, 2011, 2010 and 2009, respectively.

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 Intrepid, Seawell and Express and $375,000 on the Caesar. In addition to the primary deductibles the vessels are subject to an Annual Aggregate Deductible of $1.25 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

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$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, 2011 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.

Litigation, Contingencies and Claims

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 terms of 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 counterclaims against them. In the first quarter of 2010, we recorded 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. These amounts were recorded as selling, general and administrative expenses in the accompanying consolidated statements of operations.

In 2006, 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 and claims 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 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 related to a subsea construction and diving contract we entered into in December 2006 in India for the tax years 2007, 2008, 2009, and 2010. 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 relate 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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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. We had one such contract in 2008, which was ultimately terminated because of the delay in the delivery of the Caesar. As of December 31, 2008, we estimated the loss under this contract at $9.0 million. In the second quarter of 2009, services under this contract were substantially completed by a third party and we revised our estimated loss to approximately $15.8 million. Subsequently, we settled the liability for $12.7 million. Accordingly we included an additional $3.7 million of charges to cost of sales in the accompanying consolidated statements of operations for the year ended December 31, 2009. We paid $7.2 million of the loss in 2008 and the remaining $5.5 million in the second quarter of 2010.

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 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.

Commitments

Since September 30, 2009, we have added three vessels to our fleet. The Well Enhancer joined our well operations fleet in October 2009, and the Caesar, a pipelay vessel, and the HP I, a floating production unit vessel, were placed in service in the first half of 2010. The construction of these three vessels has represented a substantial amount of our capital expenditures since 2007. Although all three vessels are in service, a certain amount of future capital will be required to be spent to fully complete the vessels. For example, in 2010, we completed installation of a coil tubing unit on the Well Enhancer. The timing of future capital upgrades is mainly determined by the vessel's utilization as we attempt to coordinate such activities with known gaps in its contractual backlog or when the vessel is scheduled for a regulatory inspection and/or drydocking.

In February 2012, we announced that we are initiating construction of a new multi-service semi-submersible well intervention and well operations vessel similar to our existing Q4000 vessel. This vessel is expected to be completed and placed in service in 2015.

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Note 17 — Business Segment Information

Our operations are conducted through the following lines of business: contracting services and oil and gas. We have disaggregated our contracting services operations into two reportable business segments: Contracting Services and Production Facilities. As a result, our reportable segments consisted of the following: Contracting Services, Oil and Gas and Production Facilities. Contracting Services operations include well operations and robotics, subsea construction and deepwater pipelay. Previously, we had a fourth business segment, Shelf Contracting, which represented the operations of CDI. In June 2009, we ceased consolidating CDI when our ownership interest decreased to below 50% following the sale of a substantial portion of CDI common stock held by us (Note 3). We continued to disclose the results of Shelf Contracting business as a segment up to and through June 10, 2009, the date we deconsolidated it from our financial statements. All material intercompany transactions between the segments have been eliminated.

We evaluate our performance based on income before income taxes of each segment. Segment assets are comprised of all assets attributable to the reportable segment. The majority of our Production Facilities segment (Deepwater Gateway and Independence Hub) is accounted for under the equity method of accounting. We consolidate our investment in the HP I and Kommandor LLC and its results are included within our Production Facilities segment.

The following summarizes certain financial data by business segment:

	Year Ended December 31,		
	2011	2010	2009
		(in thousands)	
Revenues			
Contracting Services	$ 738,235	$ 780,339	$ 796,158
Shelf Contracting	—	—	404,709
Oil and Gas	696,607	425,369	385,338
Production Facilities(1)	75,460	117,300	3,395
Intercompany elimination	(111,695)	(123,170)	(127,913)
Total	$1,398,607	$1,199,838	$1,461,687
Income (loss) from operations			
Contracting Services	$ 107,013	$ 77,391	$ 118,176
Shelf Contracting	—	—	59,077
Oil and Gas	129,936	(160,206)	91,668
Production Facilities(1)	38,404	63,863	(3,918)
Corporate	(39,918)	(56,609)	(47,734)
Intercompany elimination	93	(19,095)	(13,454)
Total(2)	$ 235,528	$ (94,656)	$ 203,815
Net interest expense and other			
Contracting Services	$ 765	$ 1,299	$ (2,280)
Shelf Contracting	—	—	6,642
Oil and Gas	25,833	18,886	20,152
Production Facilities	442	865	2,011
Corporate and eliminations	72,913	65,274	24,970

Total	$ 99,953	$ 86,324	$ 51,495
Equity in earnings of equity investments	$ 22,215	$ 19,469	$ 32,329
Income (loss) before income taxes			
Contracting Services	$ 97,798	$ 72,459	$ 120,456
Shelf Contracting	—	—	52,435
Oil and Gas	104,103	(179,092)	71,516
Production Facilities(1)	58,064	86,100	18,300
Corporate and eliminations	(111,985)	(143,218)	(715)
Total	$ 147,980	$ (163,751)	$ 261,992

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	Year Ended December 31, 2011	2010	2009
	(in thousands)		
Provision (benefit) for income taxes			
Contracting Services	$ 29,235	$ 42,828	$ 43,334
Shelf Contracting	—	—	16,275
Oil and Gas	35,858	(62,954)	23,352
Production Facilities	19,233	29,049	6,198
Corporate and eliminations	(69,423)	(48,521)	6,663
Total	$ 14,903	$ (39,598)	$ 95,822
Identifiable assets			
Contracting Services	$2,006,065	$1,856,016	$1,738,005
Oil and Gas	1,041,506	1,223,014	1,541,153
Production Facilities	534,776	512,990	499,497
Discontinued operations	—	—	878
Total	$3,582,347	$3,592,020	$3,779,533
Capital expenditures			
Contracting Services	$ 69,259	$ 65,949	$ 204,228
Shelf Contracting	—	—	39,569
Oil and Gas	119,614	84,554	137,168
Production Facilities	30,896	56,269	42,408
Total	$ 219,769	$ 206,772	$ 423,373
Depreciation and amortization			
Contracting Services	$ 73,291	$ 66,333	$ 53,411
Shelf Contracting	—	—	34,243
Oil and Gas	219,915	235,290	168,101
Production Facilities	14,935	9,907	3,295
Corporate and eliminations	2,962	5,586	3,567
Total	$ 311,103	$ 317,116	$ 262,617

(1) In April 2009, Kommandor LLC commenced leasing the HP I to us under terms of a charter arrangement following the completion of the initial conversion of the vessel (Note 8). The HP I was certified as a floating oil and gas production unit in June 2010 following the completion of installation of oil and gas processing facilities on the vessel. The HP I participated in the BP oil spill and containment response efforts and is currently being utilized as the processing unit for our Phoenix field.

(2) Includes $16.7 million of goodwill impairment charge for year ending December 31, 2010 related to our contracting services segment. Also includes approximately $132.6 million, $181.1 million and $120.6 million of asset impairment charges for certain oil and gas properties for the years ended December 31, 2011, 2010 and 2009 respectively.

Intercompany segment revenues during the years ended December 31, 2011, 2010 and 2009 was as follows (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Contracting Services	$ 65,638	$ 109,012	$ 120,048
Production Facilities	46,057	14,158	—
Shelf Contracting	—	—	7,865
Total	$ 111,695	$ 123,170	$ 127,913

Intercompany segment profit (loss) (which only relates to intercompany capital projects) during the years ended December 31, 2011, 2010 and 2009 was as follows (in thousands):

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	Year Ended December 31, 2011	2010	2009
Contracting Services	$ 104	$ 15,655	$ 13,205
Production Facilities	(197)	3,457	(116)
Shelf Contracting	—	—	365
Total	$ (93)	$ 19,112	$ 13,454

Revenue by individually significant country during the years ended December 31, 2011, 2010 and 2009 was as follows (in thousands):

	Year Ended December 31, 2011	2010	2009
United States	$1,013,476	$ 827,597	$ 923,481
United Kingdom	275,499	198,011	124,896
India	44,772	56,311	233,466
Other	64,860	117,919	179,844
Total	$1,398,607	$1,199,838	$1,461,687

We include the property and equipment, net in the county in which it is legally owned. The following table provides our property and equipment, net of depreciation by country (in thousands):

	Year Ended December 31, 2011	2010	2009
United States	$2,034,978	$2,236,455	$2,564,673
United Kingdom	281,430	275,012	284,637
Other	14,919	15,613	14,396
Total	$2,331,327	$2,527,080	$2,863,706

Note 18 — 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, 2011 (in thousands):

	Allowance for Uncollectible Accounts	Deferred Tax Asset Valuation Allowance
Balance, December 31, 2008	$ 5,905	$ 3,317
Additions	9,220	—
Deductions (1)	(9,953)	(3,317)
Balance, December 31, 2009	5,172	—
Additions (2)	4,108	8,497
Deductions(3)	(4,753)	—
Balance, December 31, 2010	4,527	8,497
Additions(4)	61	5,813
Deductions	(521)	—

Balance, December 31, 2011	$ 4,067	$ 14,310

(1) Amounts include reductions of $5.9 million to the allowance for uncollectible accounts and $3.3 million to the deferred tax valuation allowance to reflect the deconsolidation of Cal Dive in June 2009 (Note 3).
(2) Amounts include a $4.0 million bad debt allowance related to a large international construction contract and the valuation allowance includes a $7.3 million 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.
(3) 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 16).
(4) The valuation allowance includes $4.9 million related to our WOSEA operations and $0.9 million to our oil and gas operations in the United Kingdom. WOSEA has a full valuation allowance against its deferred tax asset balance.

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See Note 2 for a detailed discussion regarding our accounting policy on Accounts Receivable and Allowance for Uncollectible Accounts and Note 10 for a detailed discussion of the valuation allowance related to our deferred tax assets.

Note 19 — Supplemental Oil and Gas Disclosures (Unaudited)

Accounting Rules Activities

We adopted the modernized oil and gas reserve requirements for our proved reserve estimates and the related reserve report at December 31, 2009. Generally, adoption of these new regulations had little effect on our estimates of reserves however, the rule requiring development of proved undeveloped reserves within five years has subsequently affected our proved reserve estimate and could significantly impact future estimates of our proved reserves (see "Proved Undeveloped Reserves" below).

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):

	2011	2010
Unproved oil and gas properties	$ 50,389	$ 56,093
Proved oil and gas properties	2,524,304	2,691,802
Total oil and gas properties	2,574,693	2,747,895
Accumulated depletion, depreciation and amortization	(1,703,046)	(1,673,740)
Net capitalized costs	$ 871,647	$ 1,074,155

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 in the accompanying consolidated balance sheets. At December 31, 2011 and 2010, our oil and gas asset retirement obligations totaled $254.4 million and $234.9 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):

	United States	United Kingdom	Total
Year Ended December 31, 2011—			
Property acquisition costs:			
Proved properties	$ —	$ —	$ —
Unproved properties	41	—	41
Total property acquisition costs	41	—	41
Exploration costs	2,513	—	2,513
Development costs(1)	126,196	—	126,196

Asset retirement cost		26,523		19,923		46,446
Total costs incurred	$	155,273	$	19,923	$	175,196

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	United States	United Kingdom	Total
Year Ended December 31, 2010—			
Property acquisition costs:			
Proved properties	$—	$—	$—
Unproved properties	364	—	364
Total property acquisition costs	364	—	364
Exploration costs	1,362	—	1,362
Development costs(1)	53,002	—	53,002
Asset retirement cost	18,814	6,542	25,356
Total costs incurred	$73,542	$6,542	$80,084
Year Ended December 31, 2009—			
Property acquisition costs:			
Proved properties	$56	$—	$56
Unproved properties	1,829	—	1,829
Total property acquisition costs	1,885	—	1,885
Exploration costs	39,225	—	39,225
Development costs(1)	71,489	—	71,489
Asset retirement cost	66,468	2,644	69,112
Total costs incurred	$179,067	$2,644	$181,711

(1) Development costs include costs incurred to obtain access to proved reserves to drill and equip development wells. Development costs also include costs of developmental dry holes.

Results of Operations for Oil and Gas Producing Activities

Amounts in thousands:

	United States	United Kingdom	Total
Year Ended December 31, 2011—			
Revenues	$ 696,607	$ —	$ 696,607
Production (lifting) costs	176,269	3,974	180,243
Hurricane repair expense (Note 4)	(4,838)	—	(4,838)
Exploration expenses(2)	10,914	—	10,914
Depreciation, depletion, amortization and accretion	219,915	—	219,915
Proved property impairment charges and other (3)	113,439	19,967	133,406
Gain on sale or acquisition of oil and gas properties	(4,531)	—	(4,531)
Selling and administrative expenses	31,455	107	31,562
Pretax income (loss) from producing activities	153,984	(24,048)	129,936
Income tax expense (benefit)	45,233	(9,375)	35,858
Results of oil and gas producing activities(1)	$ 108,751	$ (14,673)	$ 94,078

Year Ended December 31, 2010—			
Revenues	$ 425,369	$ —	$ 425,369
Production (lifting) costs	131,156	4,529	135,685
Net hurricane costs (Note 4)	4,699	—	4,699
Exploration expenses(2)	8,276	—	8,276
Depreciation, depletion, amortization and accretion	235,243	47	235,290
Proved property impairment charges and other (3)	177,138	4,995	182,133
Gain on sale of oil and gas properties	(287)	(5,959)	(6,246)
Gain on oil and gas derivative contracts	(1,088)	—	(1,088)
Selling and administrative expenses	26,714	112	26,826
Pretax loss from producing activities	(156,482)	(3,724)	(160,206)
Income tax expense (benefit)	(62,526)	(428)	(62,954)
Results of oil and gas producing activities(1)	$ (93,956)	$ (3,296)	$ (97,252)

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	United States	United Kingdom	Total
Year Ended December 31, 2009—			
Revenues	$ 384,375	$ 963	$ 385,338
Production (lifting) costs	117,565	2,271	119,836
Net hurricane costs (Note 4)	(23,332)	—	(23,332)
Exploration expenses(2)	24,383	—	24,383
Depreciation, depletion, amortization and accretion	167,812	1,444	169,256
Proved property impairment charges and other (3)	73,407	—	73,407
Gain on sale of oil and gas properties	(1,949)	—	(1,949)
Gain on oil and gas derivative contracts	(89,485)	—	(89,485)
Selling and administrative expenses	21,495	59	21,554
Pretax loss from producing activities	94,479	(2,811)	91,668
Income tax expense (benefit)	24,280	(1,028)	23,252
Results of oil and gas producing activities(1)	$ 70,199	$ (1,783)	$ 68,416

(1) Excludes net interest expense and other.

(2) See Note 5 for additional information related to the components of our exploration costs, including impairment charges for expiring unproved leases.

(3) Other amounts represent additional asset retirement expense recorded upon completion of a field's abandonment.

Estimated Quantities of Proved Oil and Gas Reserves

We employ 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. Our internal reservoir engineers and independent petroleum engineers analyze 100% of our significant United States oil and gas fields (65 fields as of December 31, 2011). 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 engaged Huddleston & Co., Inc. ("Huddleston"), an independent reservoir engineering firm, to prepare a report to estimate our proved reserves. Huddleston prepared a report to estimate our proved reserves at December 31, 2011, 2010 and 2009. Their reserve report at December 31, 2011 is included as Exhibit 99.1 to this Annual Report.

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The following table presents our net ownership interest in proved oil reserves (MBbls):

	United States	United Kingdom	Total
Total proved reserves at December 31, 2008	32,012	—	32,012
Revision of previous estimates	232	—	232
Production	(2,741)	—	(2,741)
Purchases of reserves in place	—	—	—
Sales of reserves in place	(1)	—	(1)
Extensions and discoveries	225	—	225
Total proved reserves at December 31, 2009	29,727	—	29,727
Revision of previous estimates(1)	(1,555)	—	(1,555)
Production	(3,354)	—	(3,354)
Purchases of reserves in place	—	—	—
Sales of reserves in place	—	—	—
Extensions and discoveries	—	—	—
Total proved reserves at December 31, 2010	24,818	—	24,818
Revision of previous estimates(2)	3,475	—	3,475
Production	(5,785)	—	(5,785)
Purchases of reserves in place	—	—	—
Sales of reserves in place	(205)	—	(205)
Extensions and discoveries	386	—	386
Total proved reserves at December 31, 2011	22,689	—	22,689
Total proved developed reserves as of :			
December 31, 2008	12,809	—	12,809
December 31, 2009	14,850	—	14,850
December 31, 2010	11,796	—	11,796
December 31, 2011	12,754	—	12,754

(1) Includes an approximate 1.8 MMBbls decrease 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 of our producing fields, most notably our Bushwood field at Garden Banks Blocks 462/463/506/507, as well as changes in the field economics of some of our 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 oil spill from the Macondo well.

(2) The positive revision reflects the better than expected production volumes primarily from our Phoenix field at Green Canyon Blocks 236, 237, 238 and 282 since it began production in October 2010.

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The following table presents our net ownership interest in proved gas reserves, including natural gas liquids (MMcf):

	United States	United(1) Kingdom	Total
Total proved reserves at December 31, 2008	460,456	12,950	473,406
Revision of previous estimates (2)	(44,615)	(755)	(45,370)
Production	(27,139)	(195)	(27,334)
Purchases of reserves in place	—	—	—
Sales of reserves in place	(7,933)	—	(7,933)
Extensions and discoveries	6,546	—	6,546
Total proved reserves at December 31, 2009	387,315	12,000	399,315
Revision of previous estimates (3)	(132,954)	(12,000)	(144,954)
Production	(27,097)	—	(27,097)
Purchases of reserves in place	—	—	—
Sales of reserves in place	—	—	—
Extensions and discoveries	—	—	—
Total proved reserves at December 31, 2010	227,264	—	227,264
Revision of previous estimates(4)	(108,947)	—	(108,947)
Production	(17,458)	—	(17,458)
Purchases of reserves in place	—	—	—
Sales of reserves in place	(4,109)	—	(4,109)
Extensions and discoveries	271	—	271
Total proved reserves at December 31, 2011	97,021	—	97,021
Total proved developed reserves as of :			
December 31, 2008	256,794	950	257,744
December 31, 2009	124,763	—	124,763
December 31, 2010	75,664	—	75,664
December 31, 2011	59,859	—	59,859

(1) Reflects 50% ownership in the Camelot field's reserves in 2009 and 2008. In February 2010 we acquired the other 50% ownership interest in the Camelot field. We no longer have any development plans for the field and we intend to fully abandon the field in 2012 in accordance with the applicable regulations in the United Kingdom. See Note 5 for additional information regarding our Camelot field.

(2) Includes a 38 Bcfe reduction of the proved reserves at Bushwood field reflecting certain reservoir issues for our Noonan Gas wells subsequent to their reestablishing sustained production in January 2009 and new geologic data collected throughout 2009.

(3) Includes an approximate 131 Bcf decrease 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 of our producing fields, most notably our

Bushwood field at Garden Banks Blocks 462/463/506/507, as well as changes in the field economics of some of our 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 oil spill from the Macondo well.

(4) Decrease primarily represents a reclassification of estimate 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 our Bushwood field, where we reclassified approximately 87 Bcf at December 31, 2011.

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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):

	United States	United(1) Kingdom	Total
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)
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)
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
As of December 31, 2009—			
Future cash inflows	$3,166,306	$60,840	$3,227,146
Future costs:			
Production	(618,391)	(19,075)	(637,466)
Development and abandonment	(755,726)	(33,807)	(789,533)
Future net cash flows before income taxes	1,792,189	7,958	1,800,147
Future income tax expense	(417,042)	(1,560)	(418,602)
Future net cash flows	1,375,147	6,398	1,381,545
Discount at 10% annual rate	(387,036)	(3,449)	(390,485)
Standardized measure of discounted future	$988,111	$2,949	$991,060

net cash flows

(1) Reflects 50% ownership in the Camelot field's reserves in 2009. In February 2010 we acquired the other 50% ownership interest in the Camelot field (Note 5).

Future cash inflows are computed by applying the appropriate average twelve 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:

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	United States	United Kingdom	Total
Year Ended December 31, 2011—			
Oil price per Bbl	$ 105.35	$ —	$ 105.35
Natural gas prices per Mcf	$ 4.34	$ —	$ 4.34
Year Ended December 31, 2010—			
Oil price per Bbl	$ 77.55	$ —	$ 77.55
Natural gas prices per Mcf	$ 4.40	$ —	$ 4.40
Year Ended December 31, 2009—			
Oil price per Bbl	$ 58.05	$ —	$ 58.05
Natural gas prices per Mcf	$ 3.72	$ 5.07	$ 3.76

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,		
	2011	2010	2009
Standardized measure, beginning of year	$ 991,067	$ 991,060	$1,312,155
Changes during the year:			
Sales, net of production costs	(516,895)	(294,212)	(265,501)
Net change in prices and production costs	414,426	577,687	(245,883)
Changes in future development costs	(108,007)	84,907	(16,905)
Development costs incurred	168,005	55,646	74,133
Accretion of discount	131,464	129,083	161,254
Net change in income taxes	(54,613)	(41,115)	257,919
Purchases of reserves in place	—	—	—
Extensions and discoveries	29,479	—	10,457
Sales of reserves in place	(14,324)	—	(30,124)
Net change due to revision in quantity estimates	(186,197)	(422,987)	(85,450)

Changes in production rates (timing) and other	208,727	(89,002)	(180,995)
Total	72,065	7	(321,095)
Standardized measure, end of year	$1,063,132	$ 991,067	$ 991,060

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Note 20 — Derivative Instruments and Hedging Activities

Derivatives designated as hedging instruments as defined in FASB Codification Topic No. 815 Derivatives and Hedging (in thousands):

	As of December 31, 2011		As of December 31, 2010	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Asset Derivatives:				
Natural gas contracts	Other current assets	$ 12,957	Other current assets	$ 5,324
Oil contracts	Other current assets	8,567	Other current assets	—
Natural gas contracts	Other assets	857	Other assets	—
Interest rate swaps	Other assets	327	Other assets	—
		$ 22,708		$ 5,324

	As of December 31, 2011		As of December 31, 2010	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Liability Derivatives:				
Oil contracts	Accrued liabilities	$ 886	Accrued liabilities	$ 28,855
Interest rate swaps	Accrued liabilities	202	Accrued liabilities	1,751
Gas contracts	Other long-term liabilities	—	Other long-term liabilities	913
Oil contracts	Other long-term liabilities	1,711	Other long-term liabilities	—
Interest rate swaps	Other long-term liabilities	—	Other long-term liabilities	115
		$ 2,799		$ 31,634

Derivatives that were not designated as hedging instruments (in thousands):

	As of December 31, 2011		As of December 31, 2010	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Asset Derivatives:				
Foreign exchange forwards	Other current assets	$ 55	Other current assets	$ 148
Foreign exchange forwards	Other assets	—	Other assets	42
		$ 55		$ 190

	As of December 31, 2011		As of December 31, 2010	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Liability Derivatives:				
Foreign exchange forwards	Accrued liabilities	$ 159	Accrued liabilities	$ —
		$ 159		$ —

The following tables present the impact that derivative instruments designated as cash flow hedges had on our consolidated statement of operations for the years ended December 31, 2011, 2010 and 2009 (in thousands):

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	Gain (Loss) Recognized in OCI on Derivatives		
	2011(1)	2010	2009
Oil and natural gas commodity contracts	$ 28,749	$ (6,486)	$ (19,092)
Foreign exchange forwards	—	—	(538)
Interest rate swaps	1,294	(1,213)	712
	$ 30,043	$ (7,699)	$ (18,918)

(1) All unrealized gains (losses) related to our derivatives are expected to be reclassified into earnings by no later than December 31, 2014. The last of our interest rate swaps will be settled in January 2014. The last of our oil and natural gas commodity contracts will settle in December 2013. Most of our unrealized gain (losses) in OCI at December 31, 2011 is expected to be reclassified to earnings in 2012, including $13.4 million for our oil and natural gas contracts and $(0.1) million related to our interest swap contracts.

	Location of Gain (Loss) Reclassified from Accumulated OCI into Income	Gain (Loss) Reclassified from Accumulated OCI into Income Years Ended December 31,		
		2011	2010	2009
Oil and natural gas commodity contracts	Oil and Gas Revenues	$(21,659)	$25,575	$16,972
Interest rate swaps	Net interest expense	(2,010)	(1,849)	(1,096)
		$(23,669)	$23,726	$15,876

The following tables present the impact that derivative instruments not designated as hedges had on our consolidated statement of operations for the years ended December 31, 2011, 2010 and 2009 (in thousands):

	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives Years Ended December 31,		
		2011	2010	2009
Natural gas contracts	Gain on oil and gas derivative contracts	$ —	$ 1,088	$89,485
Foreign exchange forwards	Other income (expense)	249	(2,560)	3,279
Interest rate swaps	Other income (expense)	—	—	(468)
		$ 249	$(1,472)	$92,296

Note 21 — 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 2010 and 2009 (in thousands, except per share data):

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2011				
Net revenues	$291,607	$338,319	$ 372,496	$ 396,185
Gross profit (1)	77,076	100,198	122,295	31,023
Net income (2)	25,867	41,323	46,026	16,763
Net income applicable to common shareholders	25,857	41,313	46,016	16,753
Basic earnings per common share	0.24	0.39	0.43	0.16
Diluted earnings per common share	0.24	0.39	0.43	0.16

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	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2010				
Net revenues	$201,570	$299,262	$ 392,669	$ 306,337
Gross profit (loss) (3)	25,856	(94,818)	86,552	16,082
Net income (loss) (4)	(17,831)	(85,517)	26,171	(49,811)
Net income (loss) applicable to common shareholders	(17,891)	(85,551)	26,161	(49,821)
Basic earnings (loss) per common share	(0.17)	(0.82)	0.25	(0.48)
Diluted earnings (loss) per common share	(0.17)	(0.82)	0.25	(0.48)

(1) Includes oil and gas property impairment charges totaling $22.7 million in the second quarter of 2011 and $2.4 million in the third quarter of 2011. Our fourth quarter of 2011 includes a total of $107.5 million of impairment charges, including $79.3 million related to eight oil and gas properties to reduce them to their estimated fair value at December 31, 2011 and $28.2 million to increase certain non-producing properties estimated asset retirement obligations, including $15.9 million related to our one U.K. oil and gas property (Note 5). The fourth quarter also includes a $6.6 million impairment charge to reduce our Australian well intervention equipment to is estimated fair value at December 31, 2011. There were no asset impairment charges in the first quarter of 2011.

(2) Our fourth quarter 2011 includes a $10.6 million other than temporary impairment loss on our equity investment in our Australian joint venture (Note 7). The fourth quarter also includes a $31.3 million tax benefit related to reorganization of our Australian well intervention business.

(3) Includes oil and gas property impairment charges totaled $11.1 in the first quarter of 2010, $159.9 million in the second quarter of 2010, $0.9 million in the third quarter of 2010 and $9.2 million in the fourth quarter of 2010.

(4) Includes an impairment charges of $16.7 million to reduce goodwill associated with our Australia well intervention business in the fourth quarter of 2010 (Note 2).

Note 22 — Subsequent Event

On February 21, 2012, we entered into an amendment to our Credit Agreement. Under terms of the amendment the participating lenders agree to loan us $100 million pursuant to a new term loan (Term Loan A). The terms of the new Term Loan A are the same as those regarding the Revolving Credit Facility, with the Term Loan A requiring a $5 million annual amortization of the principal balance. The Term Loan A will fund in March 2012. See Note 9 for additional information regarding our Credit Agreement and our Senior Unsecured Notes.

Note 23 — Condensed Consolidated Guarantor and Non-Guarantor Financial Information

The payment of 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. Cal Dive and its subsidiaries were never guarantors of our Senior Unsecured Notes. 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 presented 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 relate primarily to the elimination of investments in subsidiaries and associated intercompany balances and transactions.

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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	$ 2,434	$ 48,547	$ —	$ 546,465
Accounts receivable, net	79,290	117,767	41,724	—	238,781
Unbilled revenue	10,530	155	26,690	—	37,375
Income taxes receivable	80,388	—	—	(80,388)	—
Other current assets	68,627	48,661	10,159	(5,826)	121,621
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	1,422,326	682,899	(4,844)	2,331,327
Other assets:					
Equity investments in unconsolidated affiliates	—	—	175,656	—	175,656
Equity investments in affiliates	1,952,392	37,239	—	(1,989,631)	—
Goodwill, net	—	45,107	17,108	—	62,215
Other assets, net	53,425	36,453	16,809	(37,780)	68,907
Due from subsidiaries/parent	64,655	430,496	—	(495,151)	—
	$ 2,888,550	$ 2,456,459	$ 916,766	$ (2,679,428)	$ 3,582,347
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 39,280	$ 82,750	$ 25,013	$ —	$ 147,043
Accrued liabilities	115,921	97,692	26,350	—	239,963
Income taxes payable	—	97,692	217	(96,616)	1,293
Current maturities of long-term debt	3,000	—	10,377	(5,500)	7,877
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 income taxes	231,255	88,625	103,552	(5,822)	417,610
Asset retirement obligations	—	161,208	—	—	161,208
Other long-term liabilities	4,150	4,647	571	—	9,368
Due to parent	—	—	98,285	(98,285)	—

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
	$ 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 BALANCE SHEETS
(in thousands)

	As of December 31, 2010				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 376,434	$ 3,294	$ 11,357	$ —	$ 391,085
Accounts receivable, net	61,846	91,659	23,788	—	177,293
Unbilled revenue	11,990	—	37,421	—	49,411
Income taxes receivable	19,334	—	7,195	(20,430)	6,099
Other current assets	63,306	49,557	12,889	(8,786)	116,966
Total current assets	532,910	144,510	92,650	(29,216)	740,854
Intercompany	1,906	263,920	(171,513)	(94,313)	—
Property and equipment, net	217,153	1,605,906	709,082	(5,061)	2,527,080
Other assets:					
Equity investments in unconsolidated affiliates	—	—	187,031	—	187,031
Equity investments in affiliates	1,998,289	29,899	—	(2,028,188)	—
Goodwill, net	—	45,107	17,387	—	62,494
Other assets, net	43,971	38,324	21,900	(29,634)	74,561
Due from subsidiaries/parent	95,398	105,434	—	(200,832)	—
	$ 2,889,627	$ 2,233,100	$ 856,537	$ (2,387,244)	$ 3,592,020
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 60,308	$ 56,107	$ 42,966	$ —	$ 159,381
Accrued liabilities	58,074	107,874	32,289	—	198,237
Income taxes payable	—	36,678	—	(36,678)	—
Current maturities of long-term debt	4,326	—	14,301	(8,448)	10,179
Total current liabilities	122,708	200,659	89,556	(45,126)	367,797
Long-term debt	1,237,587	—	110,166	—	1,347,753
Deferred income taxes	185,453	135,101	98,968	(5,883)	413,639
	—	170,410	—	—	170,410

Assets retirement obligations					
Other long-term liabilities	1,421	3,691	665	—	5,777
Due to parent	—	—	120,884	(120,884)	—
Total liabilities	1,547,169	509,861	420,239	(171,893)	2,305,376
Convertible preferred stock	1,000	—	—	—	1,000
Total equity	1,341,458	1,723,239	436,298	(2,215,351)	1,285,644
	$ 2,889,627	$ 2,233,100	$ 856,537	$ (2,387,244)	$ 3,592,020

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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(in thousands)

	Year Ended December 31, 2011				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$84,748	$1,059,255	$ 367,114	$ (112,510)	$ 1,398,607
Cost of sales	72,902	673,415	289,462	(111,281)	924,498
Oil and gas impairments	—	112,636	19,967	—	132,603
Exploration expense	—	10,914	—	—	10,914
Gross profit (loss)	11,846	262,290	57,685	(1,229)	330,592
Gain on sale of assets, net	(6)	4,531	—	—	4,525
Selling, general and administrative expenses	(74,205)	(38,915)	12,101	1,430	(99,589)
Loss from operations	(62,365)	227,906	69,786	201	235,528
Equity in earnings of unconsolidated affiliates	—	—	22,215	—	22,215
Equity in earnings (losses) of affiliates	262,990	7,340	—	(270,330)	—
Gain on investment in Cal Dive common stock	753	—	—	—	753
Other than temporary loss on equity investments	—	—	(10,563)	—	(10,563)
Net interest expense and other	(158,299)	(32,345)	67,181	23,510	(99,953)
Income before income taxes	43,079	202,901	148,619	(246,619)	147,980
(Benefit) provision for income taxes	(63,242)	69,890	8,186	69	14,903
Net income (loss), including noncontrolling interests	106,321	133,011	140,433	(246,688)	133,077
Net income applicable to noncontrolling interests	—	—	—	(3,098)	(3,098)
Net income (loss) applicable to Helix	106,321	133,011	140,433	(249,786)	129,979
Preferred stock dividends	(40)	—	—	—	(40)
Net income (loss) applicable to Helix common shareholders	$106,281	$133,011	$ 140,433	$ (249,786)	$ 129,939

	Year Ended December 31, 2010				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$183,147	$801,503	$ 334,726	$ (119,538)	$ 1,199,838
Cost of sales	124,722	659,859	297,056	(104,830)	976,807
Oil and gas impairments	—	176,088	4,995	—	181,083
Exploration expense	—	8,276	—	—	8,276
Gross profit (loss)	58,425	(42,720)	32,675	(14,708)	33,672
Goodwill impairment	—	—	(16,743)	—	(16,743)
	—	1,088	—	—	1,088

Gain on oil and gas derivative commodity contracts					
Gain on sale of assets, net	3,159	287	5,959	—	9,405
Selling, general and administrative expenses	(67,165)	(34,233)	(22,482)	1,802	(122,078)
Loss from operations	(5,581)	(75,578)	(591)	(12,906)	(94,656)
Equity in earnings of unconsolidated affiliates	—	—	19,469	—	19,469
Equity in earnings (losses) of affiliates	(60,443)	8,473	—	51,970	—
Other than temporary loss on equity investments	(2,240)	—	—	—	(2,240)
Net interest expense and other	(59,522)	(21,677)	(5,125)	—	(86,324)
Income before income taxes	(127,786)	(88,782)	13,753	39,064	(163,751)
(Benefit) provision for income taxes	(9,175)	(35,299)	9,405	(4,529)	(39,598)
Net income (loss), including noncontrolling interests	(118,611)	(53,483)	4,348	43,593	(124,153)
Net income applicable to noncontrolling interests	—	—	—	(2,835)	(2,835)
Net income (loss) applicable to Helix	(118,611)	(53,483)	4,348	40,758	(126,988)
Preferred stock dividends	(114)	—	—	—	(114)
Net income (loss) applicable to Helix common shareholders	$(118,725)	$(53,483)	$ 4,348	$ 40,758	$ (127,102)

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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(in thousands)

	Year Ended December 31, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$211,222	$ 701,706	$ 648,705	$ (99,946)	$ 1,461,687
Cost of sales	162,225	484,802	521,689	(95,124)	1,073,592
Oil and gas impairments	—	120,550	—	—	120,550
Exploration expense	—	24,383	—	—	24,383
Gross profit (loss)	48,997	71,971	127,016	(4,822)	243,162
Gain on oil and gas derivative commodity contracts	—	89,485	—	—	89,485
Gain on sale of assets, net	—	2,019	—	—	2,019
Selling, general and administrative expenses	(52,101)	(28,520)	(53,919)	3,689	(130,851)
Income (loss) from operations	(3,104)	134,955	73,097	(1,133)	203,815
Equity in earnings of unconsolidated affiliates	—	—	33,229	(900)	32,329
Equity in earnings (losses) of affiliates	145,340	(1,725)	—	(143,615)	—
Gain on investment in of Cal Dive common stock	77,343	—	—	—	77,343
Net interest expense and other	(18,188)	(16,978)	(15,341)	(988)	(51,495)
Income before income taxes	201,391	116,252	90,985	(146,636)	261,992
(Benefit) provision for income taxes	43,417	39,855	13,571	(1,021)	95,822
Income (loss) from continuing operations	157,974	76,397	77,414	(145,615)	166,170
Discontinued operations, net of tax	99	—	9,482	—	9,581
Net income (loss), including noncontrolling interests	158,073	76,397	86,896	(145,615)	175,751
Net income applicable to noncontrolling interests	—	—	—	(19,697)	(19,697)
Net income (loss) applicable to Helix	158,073	76,397	86,896	(165,312)	156,054
	(54,187)	—	—	—	(54,187)

Preferred stock dividends									
Net income (loss) applicable to Helix common shareholders	$103,886	$	76,397	$	86,896	$	(165,312)	$	101,867

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HELIX ENERGY SOLUTIONS GROUP, INC.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	For the Year Ended December 31, 2011				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
			(in thousands)		
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) to net cash provided by (used in) operating activities:					
Equity in earnings of affiliates	(262,990)	(7,340)	—	270,330	—
Other adjustments	39,860	353,728	40,293	198	434,079
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)	(174,739)	(12,613)	—	(219,769)
Investments in equity investments	—	—	(2,699)	—	(2,699)
Distributions from equity investments, net	—	—	3,965	—	3,965
Proceeds from sale of Cal Dive common stock	3,588	—	—	—	3,588
Other, net	—	32,598	—	—	32,598
Net cash used in investing activities	(28,829)	(142,141)	(11,347)	—	(182,317)
Cash flows from financing activities:					
Borrowings on revolvers	109,400	—	—	—	109,400
Repayments on revolvers	(109,400)	—	—	—	(109,400)
Repayments of debt	(208,085)	—	(4,645)	—	(212,730)
Loan notes repayment	—	—	(1,215)	—	(1,215)
Deferred financing costs	(9,311)	—	—	—	(9,311)
Preferred stock dividends paid	(40)	—	—	—	(40)
Repurchase of common stock	(7,604)	—	—	—	(7,604)
Excess tax benefit from stock-based compensation	(1,013)	—	—	—	(1,013)
Exercise of stock options, net	2,018	—	—	—	2,018
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 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

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HELIX ENERGY SOLUTIONS GROUP, INC.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	For the Year Ended December 31, 2010				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
	(in thousands)				
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) to net cash provided by (used in) operating activities:					
Equity in earnings of affiliates	60,443	(8,473)	—	(51,970)	—
Other adjustments	94,376	305,649	76,865	(21,283)	455,607
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)	(121,709)	(28,413)	—	(206,772)
Investments in equity investments	—	—	(8,253)	—	(8,253)
Distributions from equity investments, net	—	—	10,539	—	10,539
Proceeds from insurance reimbursement	7,020	9,086	—	—	16,106
Proceeds from sale of Cal Dive common stock	—	—	—	—	—
Proceeds from sales of property	6,042	852	—	—	6,894
Increases in restricted cash	—	(70)	—	—	(70)
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)
Loan notes repayment	—	—	(2,517)	—	(2,517)
Deferred financing costs	(2,947)	—	—	—	(2,947)
Preferred stock dividends paid	(114)	—	—	—	(114)
Repurchase of common stock	(11,680)	—	—	—	(11,680)
Excess tax benefit from stock-based compensation	(3,945)	—	—	—	(3,945)
Exercise of stock options, net	674	—	—	—	674
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

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HELIX ENERGY SOLUTIONS GROUP, INC.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	For the Year Ended December 31, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
	(in thousands)				
Cash flows from operating activities:					
Net income (loss), including noncontrolling interests	$ 158,073	$ 76,397	$ 86,896	$ (145,615	$ 175,751
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:					
Equity in earnings of unconsolidated affiliates	—	—	(7,220)	899	(6,321)
Equity in earnings of affiliates	(145,340)	1,725	—	143,615	—
Other adjustments	26,633	163,451	82,411	(17,987	254,508
Net cash provided by (used in) operating activities	39,366	241,573	162,087	(19,088	423,938
Net cash used in discontinued operations	—	—	(6,261)	—	(6,261)
Net cash provided by (used in) operating activities	39,366	241,573	155,826	(19,088	417,677
Cash flows from investing activities:					
Capital expenditures	(35,657)	(245,354)	(142,362)	—	(423,373)
Acquisition of businesses, net of cash acquired	—	—	—	—	—
Investments in equity investments	—	—	(1,657)	—	(1,657)
Distributions from equity investments, net	—	—	6,742	—	6,742
Increases in restricted cash	—	(6)	—	—	(6)
Proceeds from sale of Cal Dive common stock	504,168	—	(112,995)	(86,000	305,173
Proceeds from sales of property	—	23,717	—	—	23,717
	468,511	(221,643)	(250,272)	(86,000	(89,404)

Net cash provided by (used in) investing activities					
Net cash provided by discontinued operations	—	—	20,872	—	20,872
Net cash provided by (used in) investing activities	468,511	(221,643)	(229,400)	(86,000	(68,532)
Cash flows from financing activities:					
Borrowings on revolvers	—	—	100,000	—	100,000
Repayments on revolvers	(349,500)	—	—	—	(349,500)
Repayments of debt	(4,326)	—	(24,214)	—	(28,540)
Loan notes repayment	—	—	(2,130)	—	(2,130)
Deferred financing costs	(6,970)	—	—	—	(6,970)
Preferred stock dividends paid	(645)	—	—	—	(645)
Repurchase of common stock	(13,995)	—	(86,000)	86,000	(13,995)
Excess tax benefit from stock-based compensation	895	—	—	—	895
Exercise of stock options, net	176	—	—	—	176
Intercompany financing	(23,474)	(22,391)	26,777	19,088	—
Net cash provided by (used in) financing activities	(397,839)	(22,391)	14,433	105,088	(300,709)
Effect of exchange rate changes on cash and cash equivalents	—	—	(1,376)	—	(1,376)
Net increase (decrease) in cash and cash equivalents	110,038	(2,461)	(60,517)	—	47,060
Cash and cash equivalents:					
Balance, beginning of year	148,704	4,983	69,926	—	223,613
Balance, end of year	$ 258,742	$ 2,522	$ 9,409	$ —	$ 270,673

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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, 2011. 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, 2011 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 2011 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 75 and page 76, respectively.

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 2012 Annual Meeting of Shareholders to be held on May 9, 2012. 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:

Helix Energy Solutions Group, Inc.
ATTN: Corporate Secretary
400 N. Sam Houston Parkway E., Suite 400
Houston, Texas 77060

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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 2012 Annual Meeting of Shareholders to be held on May 9, 2012.

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

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with our 2012 Annual Meeting of Shareholders to be held on May 9, 2012.

Item 13. Certain Relationships and Related Transactions.

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 2012 Annual Meeting of Shareholders to be held on May 9, 2012.

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 2012 Annual Meeting of Shareholders to be held on May 9, 2012.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

(1) Financial Statements.

The following financial statements included on pages 75 through 142 in this Annual Report are for the fiscal year ended December 31, 2011.

- 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, 2011 and 2010
- Consolidated Statements of Operations for the Years Ended December 31, 2011, 2010 and 2009
- Consolidated Statements of Shareholders’ Equity for the Years Ended December 31, 2011, 2010 and 2009
- Consolidated Statements of Cash Flows for the Years Ended December 31, 2011, 2010 and 2009
- 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 146 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 24, 2012

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

Signature	Title	Date
/s/ OWEN KRATZ Owen Kratz	President, Chief Executive Officer and Director (principal executive officer)	February 24, 2012
/s/ ANTHONY TRIPODO Anthony Tripodo	Executive Vice President and Chief Financial Officer (principal financial officer)	February 24, 2012
/s/ LLOYD A. HAJDIK Lloyd A. Hajdik	Senior Vice President — Finance and Chief Accounting Officer (principal accounting officer)	February 24, 2012
/s/ JOHN V. LOVOI John V. Lovoi	Director	February 24, 2012
/s/ T. WILLIAM PORTER T. William Porter	Director	February 24, 2012
/s/ NANCY K. QUINN Nancy K. Quinn	Director	February 24, 2012
/s/ WILLIAM L. TRANSIER William L. Transier	Director	February 24, 2012
/s/ JAMES A. WATT James A. Watt	Director	February 24, 2012

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INDEX TO EXHIBITS

Exhibits	
2.1	Agreement and Plan of Merger dated January 22, 2006, among Cal Dive International, Inc. and Remington Oil and Gas Corporation, incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K/A, filed by the registrant with the Securities and Exchange Commission on January 25, 2006 (the "Form 8-K/A").
2.2	Amendment No. 1 to Agreement and Plan of Merger dated January 24, 2006, by and among, Cal Dive International, Inc., Cal Dive Merger — Delaware, Inc. and Remington Oil and Gas Corporation, incorporated by reference to Exhibit 2.2 to the Form 8-K/A.
3.1	2005 Amended and Restated Articles of Incorporation, as amended, of registrant, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by registrant with the Securities and Exchange Commission on March 1, 2006.
3.2	Second Amended and Restated By-Laws of Helix, as amended, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on September 28, 2006.
3.3	Certificate of Rights and Preferences for Series A-1 Cumulative Convertible Preferred Stock, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by registrant with the Securities and Exchange Commission on January 22, 2003 (the "2003 Form 8-K").
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, incorporated by reference to Exhibit 4.1 to the registrant's Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on July 5, 2006.
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 incorporated by reference to Exhibit 10.3 to the December 2007 8-K.
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, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on October 13, 2009.
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. Incorporated by reference to Exhibit 10.1 to the registrant's Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on February 24, 2010.
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. Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by registrant with Securities and Exchange Commission on June 8, 2011.
4.6 *	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.
4.7	Form of Common Stock certificate, incorporated by reference to Exhibit 4.7 to the Form 8-A filed by the Registrant with the Securities and Exchange Commission on June 30, 2006.
4.8	Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of August 16, 2000, incorporated by reference to Exhibit 4.4 to the 2001 Form 10-K.
4.9	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, incorporated by reference to Exhibit 4.9 to the Form 10-K/A filed with the Securities and Exchange Commission on April 8, 2003.
4.10	

	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, incorporated by reference to Exhibit 4.4 to the Form S-3 filed with the Securities and Exchange Commission on February 26, 2003.
4.11	First Amended and Restated Agreement dated January 17, 2003, but effective as of December 31, 2002, by and between Helix Energy Solutions Group, Inc. and Fletcher International, Ltd., incorporated by reference to Exhibit 10.1 to the 2003 Form 8-K.

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4.12	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, incorporated by reference to Exhibit 4.12 to Annual Report for the year ended December 31, 2004, filed by the registrant with the Securities Exchange Commission on March 16, 2005 (the "2004 10-K").
4.13	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 , incorporated by reference to Exhibit 4.13 to the 2004 10-K.
4.14	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., incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on April 4, 2005 (the "April 2005 8-K").
4.15	Form of 3.25% Convertible Senior Note due 2025 (filed as Exhibit A to Exhibit 4.15).
4.16	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, incorporated by reference to Exhibit 4.3 to the April 2005 8-K.
4.17	Trust Indenture, dated as of August 16, 2000, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on October 6, 2005 (the "October 2005 8-K").
4.18	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, incorporated by reference to Exhibit 4.2 to the October 2005 8-K.
4.19	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, incorporated by reference to Exhibit 4.3 to the October 2005 8-K.
4.20	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, incorporated by reference to Exhibit 4.4 to the October 2005 8-K.
4.21	Supplement No. 4 to Trust Indenture, dated September 30, 2005, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.5 to the October 2005 8-K.
4.23	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 4.21).
4.24	Form of Third Amended and Restated Promissory Note to United States of America, incorporated by reference to Exhibit 4.6 to the October 2005 8-K.
4.25	Term Loan Agreement by and among Kommandor LLC, Nordea Bank Norge ASA, as arranger and agent, Nordea Bank Finland Plc, as swap bank, together with the other lender parties thereto, effective as of June 13, 2007 incorporated by reference to Exhibit 4.7 to the registrants Quarterly Report on Form 10-Q for the fiscal quarter ended June 30, 2007, file by the registrant with the Securities and Exchange Commission on August 3, 2007.
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. incorporated by reference to Exhibit 4.1 to the registrants Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on December 21, 2007 (the "December 2007 8-K").
10.1	1995 Long Term Incentive Plan, as amended, incorporated by reference to Exhibit 10.3 to the Form S-1.
10.2	Amendment to 1995 Long Term Incentive Plan of Helix Energy Solutions Group, Inc.
10.3	2009 Long-Term Incentive Cash Plan of Helix Energy Solutions Group, Inc., incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on January 6, 2009 (the "January 2009 8-K").
10.4	Form of Award Letter related to the 2009 Long-Term Incentive Cash Plan, incorporated by reference to Exhibit 10.2 to the January 2009 8-K.
10.5	Employment Agreement between Owen Kratz and Company dated February 28, 1999, incorporated by reference to Exhibit 10.5 to the Annual Report for the fiscal year ended December 31, 1998, filed by the

	registrant with the Securities and Exchange Commission on March 31, 1999 (the "1998 Form 10-K").
10.6	Employment Agreement between Owen Kratz and Company dated November 17, 2008, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on November 19, 2008 (the "November 2008 8-K").

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10.7	Helix 2005 Long Term Incentive Plan, including the Form of Restricted Stock Award Agreement, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on May 12, 2005.
10.8	Amendment to 2005 Long Term Incentive Plan of Helix Energy Solutions Group, Inc.
10.11	Separation and Release Agreement between Helix Energy Solutions Group, Inc. and Bart H. Heijermans dated January 21, 2011, incorporated by reference to Exhibit 10.1 to the January 24, 2011 Form 8-K.
10.12	Stock and Cash Award Amendment Agreement effective January 21, 2011, incorporated by reference to Exhibit 10.2 to the January 24, 2011 Form 8-K.
10.13	Employment Agreement between Alisa B. Johnson and Company dated September 18, 2006, incorporated by reference to Exhibit 10.2 to the 2006 Form 10-Q.
10.14	Employment Agreement between Alisa B. Johnson and Company dated November 17, 2008, incorporated by reference to Exhibit 10.3 to the November 2008 8-K.
10.15	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, incorporated by reference to Exhibit 10.1 to December 2007 8-K.
10.16	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 incorporated by reference to Exhibit 10.2 to the December 2007 8-K.
10.17	Employment Agreement between Anthony Tripodo and the Company dated June 25, 2008, incorporated by reference to Exhibit 10.2 to the June 2008 8-K.
10.18	Employment Agreeement by and between Helix Energy Solutions Group, Inc. and Johnny Edwards dated May 11, 2011. Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by reegistrant with the Securities and Exchange Commission on May 13, 2011.
10.19	Employment Agreeement by and between Helix Energy Solutions Group, Inc. and Clifford Chamblee dated May 11, 2011. Incorporated by reference to Exhibit 10.3 to the Quaterly Report on Form 10-Q, filed by reegistrant with the Securities and Exchange Commission on July 27, 2011
10.20	First Amendment to Employment Agreement between Anthony Tripodo adn the Company dated November 17, 2008, incorporated by reference to Exhibit 10.5 to the November 2008 Form 8-K.
0.21	Employment Agreement between Lloyd A. Hajdik and the Company dated November 17, 2008, incorporated by reference to Exhibit 10.4 to the November 2008 Form 8-K.
10.22	Stock Repurchase Agreement betweeen Company and Cal Dive International, Inc. dated January 23, 2009, incoporated by reference to Exhibit 10.1 to teh Current Report on Form 8-K, filed by registrant with the Securities and Exchange Commission on January 28, 2009.
10.23	Stock Repurchase Agreement betweeen Company and Cal Dive International, Inc. dated May 29, 2009, incoporated by reference to Exhibit 10.1 to teh Current Report on Form 8-K, filed by registrant with the Securities and Exchange Commission on June 1, 2009.
14.1	Code of Ethics for Chief Executive Officer and Senior Financial Officers, incorporated by reference to Exhibit 14.1 to the Registrant's Current Report on Form 8-K, filed with the Securities and Exchange Commission on December 7, 2009.
21.1 *	List of Subsidiaries of the Company.
23.1 *	Consent of Ernst & Young LLP.
23.2 *	Consent of Huddleston & Co., Inc.
23.3 *	Consent of Deloitte & Touche LLP. (Deepwater Gateway L.L.C.).
23.4 *	Consent of Deloitte & Touche LLP. (Independence Hub LLC).

31.1 *	Certification Pursuant to Rule 13a-14(a) under the Securities and Exchange Act of 1934 by Owen Kratz, Chief Executive Officer.
31.2 *	Certification Pursuant to Rule 13a-14(a) under the Securities and 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.
99.1 *	Report of Huddleston & Co., Inc.

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101.INS**	XBRL Instance Document
101.SCH**	XBRL Schema Document
101.CAL**	XBRL Calculation Linkbase Document
101.PRE**	XBRL Presentation Linkbase Document
101.DEF**	XBRL Definition Linkbase Document
101.LAB**	XBRL Label Linkbase Document

* Filed herewith.

** Furnished herewith.

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