HELIX ENERGY SOLUTIONS GROUP INC
Form 10-K
February 25, 2011

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, 2010
	or
r	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. þ Yes r No

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). þYes rNo

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. r

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 r	Non-accelerated filer r (Do not check if a smaller reporting company)	Smaller reporting company r

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant based on the last reported sales price of the Registrant's Common Stock on June 30, 2010 was approximately $1.1 billion.

The number of shares of the registrant's Common Stock outstanding as of February 18, 2011 was 105,901,063.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement for the Annual Meeting of Shareholders to be held on May 11, 2011, are incorporated by reference into Part III hereof.

Table of Contents

HELIX ENERGY SOLUTIONS GROUP, INC. INDEX — FORM 10-K

Table of Contents

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 any Securities and Exchange Commission (“SEC”) or other governmental or regulatory inquiry or investigation;
- statements regarding anticipated legislative, governmental, regulatory, administrative or other public body actions, requirements, permits or decisions;
- 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 continuing weak 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 new regulations on the offshore Gulf of Mexico oil and gas operations;

- uncertainties regarding our ability to replace depletion;
- unexpected 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;
- 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 derivative activities;
- the results of our continuing efforts to control or reduce costs and improve performance;
- the success of our risk management activities;

- the effects of competition;
- the availability (or lack thereof) of capital (including any financing) to fund our business strategy and/or operations and the terms of any such financing;
- the impact of current and future laws and governmental regulations, including tax and accounting developments;
- the effect of adverse weather conditions and/or other risks associated with marine operations;
- the 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. 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 as well as our investment in a dynamically positioned floating production vessel (the "Helix Producer I or HP I"). Our Oil and Gas segment engages in prospect generation, exploration, development and production activities. Our operations are primarily located in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions.

Since 2008, we have focused the future of the Company around our Contracting Services businesses, including subsea construction, well operations and robotics 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 2010. Our principal executive officer and our principal financial officer have made the certifications required under Section 302 of the Sarbanes-Oxley Act, which are included as exhibits to this Annual Report.

Please refer to the subsection "— Certain Definitions" on page 16 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 outstanding 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 its remaining ownership interests in Cal Dive during 2009 (see "Contracting Services Operations – Shelf Contracting" below and Note 3). Prior to the divestiture of CDI, Shelf Contracting Services was a fourth reporting business segment.

Table of Contents

OUR STRATEGY

In December 2008, we announced our intention to focus and shape the future direction of the Company around our subsea construction, well operations and robotics services that comprise our Contracting Services business. To achieve this strategic objective we have focused on opportunities to sell certain non-core assets, such as:

* all or a portion of our oil and gas assets; and
* our remaining interest in CDI.

Since the beginning of 2009, dispositions of non-core business assets resulted in receipt of the following pre-tax proceeds:

* Approximately $25 million from the sale of six 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 two separate public secondary offerings 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.

In March 2010, we announced the engagement of advisors to further assist us with evaluating potential alternatives for the disposition of our oil and gas business. At the time of the filing of this Annual Report, we do not have an approved or definitive plan for the disposition of our oil and gas business. We are unable to be specific regarding a timetable for any disposition, the completion of which will be largely dependent on the evolving economic and financial market conditions as well as regulatory developments with respect to the Gulf of Mexico oil and gas business.

A 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 finding and 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 objectives drives our ability to achieve our primary goal 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 may make strategic investments in capital projects that expand our service capabilities or add capacity to existing services in our key operating regions. Our more recent capital investments have included: 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 servicing capabilities, including installation of a coiled-tubing unit in 2010.

We developed the Helix Fast Response System (“HFRS”) as a culmination of our experience as a responder in the Macondo oil spill response and containment efforts. We have executed agreements for the HFRS to be named as a spill response resource for the U.S. Gulf of Mexico oil and gas producers in their submittal of the now required oil spill response plans with state and federal authorities. The HFRS centers on two vessels, the HP I and the Q4000, both of which played a key role in the Macondo 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 ("CGA"), a non-profit industry group, making the HFRS available for a two-year term to CGA participants in the event of a Gulf of Mexico well control incident in exchange for a retainer fee. In addition to the agreement with CGA, we also have signed separate utilization agreements with 20 CGA participant member companies to date specifying the day rates to be charged should the HFRS solution be deployed. The retainer fee associated with HFRS will be a component of our Production Facilities business segment.

Table of Contents

Monetize Oil and Gas Reserves and Non-Core Assets. As previously disclosed, we are pursuing potential opportunities to sell all or a portion of our oil and gas interests. Until such time as we dispose of our oil and gas business, 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. See “Contracting Services – Shelf Contracting below and Note 3 for information regarding our multiple sales transactions involving our ownership interest in Cal Dive.

Generate Prospects and Focus Exploration Drilling on Select Deepwater Prospects. Our oil and gas operations continue to function normally notwithstanding our publicly announced plans regarding efforts to dispose of all or part of this business and despite the effects of new regulations over oil and gas operations in the Gulf of Mexico. This means we will continue to generate prospects and expect to drill in areas we believe are likely to contain oil and natural gas reserves, and where our contracting services assets can 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, 2010, our PUD category represented approximately 230 Bcfe or 61% 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 finding and developing offshore reservoirs and maximizing production economics. These “life of field” services are represented by four disciplines: (1) subsea construction, (2) well operations, (3) robotics and (4) production facilities. We have disaggregated our contracting service operations into two continuing 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;

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

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

- Production facilities. We 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 one of our oil and gas fields. 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.

As of December 31, 2010, our contracting services operations’ backlog supported by written agreements or contracts totaled $267.3 million, of which $218.8 million is expected to be performed in 2011. At December 31, 2009, our backlog totaled $251.0 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.

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 deploy capital for offshore exploration, drilling and production operations. Generally, spending for our contracting services business fluctuates directly with the direction of oil and natural gas prices. However, some of our Contracting Services will often lag drilling operations by a period of ranging from 6 to 18

Table of Contents

months, meaning that even if there were a sudden surge in deepwater drilling in the Gulf of Mexico it would probably still be some time before we would start servicing 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 excess capacity, geopolitical issues, weather and several other factors.

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 Macondo well explosion and subsequent 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 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.

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 has a state-of-the-art DP-2 system. In January 2010, the Caesar arrived in the Gulf of Mexico after its conversion into a subsea pipelay asset capable of laying rigid pipe up to 36 inches in diameter. The Caesar was placed in service in May 2010 following completion of additional upgrades. We also periodically provide construction services from our well operations vessels, the Seawell, the Q4000 and the recently constructed Well Enhancer, which was placed in service in October 2009.

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

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 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. The Q4000, also served as a key component in the Macondo well oil spill response and containment efforts in the Gulf of Mexico. 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 a newbuild vessel, the Well Enhancer. The Well Enhancer joined our fleet in October 2009 in the North Sea region.

Table of Contents

Our operations expanded within the Asia Pacific region following the acquisition of a well established Australian well operations company in 2006. In February 2010, we announced the formation of a joint venture with Australian-based engineering and construction company Clough Limited, to provide a range of subsea services to offshore operators in the Asia Pacific region. Services provided by the joint venture, named Clough Helix Pty Ltd, will include subsea well intervention and well abandonment, SURF (subsea infrastructure, umbilical, riser and flowline installation), saturation and air diving and subsea inspection, repair and maintenance services.

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 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 39 ROVs and five trencher systems operate in the Gulf of Mexico, North Sea, Asia Pacific and West Africa regions. We currently lease three vessels to support our Robotics services but we have historically engaged additional vessels on short term (spot) charters as needed.

The results of Robotics are reported within our Contracting Services 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). 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.

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 historically invested in over-sized facilities that allow 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. 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 and is 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 of natural gas production per day from multiple ultra-deepwater fields in the previously untapped 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 70 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, this re-deployable facility is expected to be moved to a new location, contracted to a third party, or 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 will pay us a fixed retainer fee for our vessels, the Q4000 and HP I, to be named as spill response resources in filed response plans filed with federal and state authorities. This retainer fee will be considered a component of our production facilities business segment.

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

OIL & GAS OPERATIONS

We formed our oil and gas business unit in 1992 to develop and provide more efficient solutions for offshore abandonment requirements, to expand the utilization of our contracting services assets and to achieve incremental returns. 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. 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, 2010, our estimated proved reserves totaled approximately 376 Bcfe, all of which are associated with properties located in the Gulf of Mexico.

As we have publicly announced, we are seeking opportunities to monetize the value of our oil and gas assets through the disposition of all or a portion of our oil and gas operations. Although this is our intention, until such time as an acceptable offer is made for our properties, we will continue to build on their value by operating them consistent with our past practices. We cannot provide assurances that the sale of all or any portion of our oil and gas operations will be completed or that we will be able to negotiate an acceptable price or acceptable terms. 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 meaningfully improve the economics of a reservoir that would 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 and may provide significant backlog for our construction assets.

Our oil and gas operations have a significant prospect inventory, mostly in the Deepwater, which we believe may generate significant life of field services for our 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 contractual obligations. We believe we have a strong reputation among major and independent oil companies. In addition, our reservoir engineering and geophysical expertise,

Table of Contents

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 as our Oil and Gas segment (Note 17).

GEOGRAPHIC AREAS

Revenue by geographic region is as follows (in thousands):

	Year Ended December 31,		
	2010	2009	2008
United States	$ 827,597	$ 923,481	$ 1,394,108
United Kingdom	198,011	124,896	160,186
India	56,311	233,466	214,288
Other	117,919	179,844	345,492
Total	$ 1,199,838	$ 1,461,687	$ 2,114,074

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 geographic region (in thousands):

	Year Ended December 31,		
	2010	2009	2008
United States	$ 2,236,455	$ 2,564,673	$ 3,170,866
United Kingdom	275,012	284,637	206,009
Other	15,613	14,396	41,568
Total	$ 2,527,080	$ 2,863,706	$ 3,418,443

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: 2010 — Shell (29%) and BP Plc (17%); 2009—Shell (19%) and 2008 — Louis Dreyfus Energy Services (10%) and Shell (15%). These customers were primarily purchasers of our oil and natural gas production. We estimate that in 2010 we provided subsea services to over 100 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, 2010, our contracting services operations' backlog supported by written agreements or contracts totaled $267.3 million, of which $218.8 million is expected to be performed in 2011. 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.

Table of Contents

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 competitors on the outer continental shelf ("OCS") include Global Industries, Ltd., Oceaneering International, Inc. and a number of smaller companies, some of which only operate a single vessel and often compete solely on price. For Deepwater projects, our principal competitors include, Allseas Group S.A., Subsea 7 S.A. and Technip. 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"), the Bureau of Ocean Energy Management, Regulation, and Enforcement ("BOEMRE") and the U.S. Customs Service, as well as private industry organizations such as the American Bureau of Shipping ("ABS"). In the North Sea, international regulations govern working hours and a specified working environment, as well as standards for diving procedures, equipment and diver health. These North Sea standards are some of the most stringent worldwide. In the absence of any specific regulation, our North Sea operations adhere to standards set by the International Marine Contractors Association and the International Maritime Organization. In addition, we operate in other foreign jurisdictions that have various types of governmental laws and regulations to which we are subject.

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

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

The BOEMRE 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 BOEMRE.

We acquire production rights to offshore mature oil and gas properties under federal oil and gas leases, which the BOEMRE administers. These leases contain relatively standardized terms and require compliance with detailed BOEMRE regulations and orders pursuant to the Outer Continental Shelf Lands Act ("OCSLA"). These BOEMRE directives are subject to change. The BOEMRE has promulgated regulations requiring offshore production facilities located on the OCS to meet stringent engineering and construction specifications. The BOEMRE also has issued regulations restricting the flaring or venting of natural gas and prohibiting the burning of liquid hydrocarbons without prior authorization. Similarly, the BOEMRE has promulgated other regulations governing the plugging and abandonment of wells located offshore and the removal of all production facilities. Finally, under certain circumstances, the BOEMRE 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). BOEMRE also plans to conduct inspections of each deepwater drilling operation for compliance with BOEMRE'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 Workplace Safety Rule (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. The Department of the Interior has a process underway regarding the establishment of a mechanism relating to the availability of blowout containment resources, and it is expected that this mechanism will be implemented in the near future. It is also expected that the BOEMRE will issue further regulations regarding deepwater offshore drilling.

Under the OCSLA and the Federal Oil and Gas Royalty Management Act, BOEMRE also administers oil and gas leases and 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 BOEMRE.

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 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 BOEMRE has promulgated regulations implementing these financial responsibility requirements for covered offshore facilities. Under the BOEMRE 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 BOEMRE 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

Table of Contents

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.

On June 26, 2009, the U.S. House of Representatives approved adoption of the “American Clean Energy and Security Act of 2009,” also known as the “Waxman-Markey Cap and Trade legislation,” or “ACESA.” The purpose of ACESA is to control and reduce emissions of greenhouse gases in the United States. The U.S. Senate has begun work on its own legislation for controlling and reducing emissions of greenhouse gases in the United States. For legislation to become law, both chambers of U.S Congress would be required to approve identical legislation. It is not possible at this time to predict whether or when the Senate may act on climate change legislation, how any bill approved by the Senate would be reconciled with ACESA, or how federal legislation may be reconciled with state and regional requirements.

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 subsea construction, well operations and robotics 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.

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 two years because premium and deductibles would

Table of Contents

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 a Catastrophic Bond instrument for the periods July 1, 2009 through June 30, 2010 and July 1, 2010 through June 30, 2011. 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, 2010, we had 1,590 employees, nearly 650 of which were salaried personnel. As of December 31, 2010, we also contracted with third parties to utilize 140 non-U.S. citizens to crew our foreign flag 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, 2010, and copies of our Quarterly Reports on Form 10-Q for 2010 and 2011 and any Current Reports on Form 8-K for 2010 and 2011, 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 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.

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.

BOEMRE: The Bureau of Ocean Energy Management, Regulation and Enforcement, an agency of the Department of Interior, having 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 is 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.

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.

Table of Contents

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.

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

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

MSV: Multipurpose support vessel.

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), Global Industries, Ltd. (NASDAQ: GLBL), McDermott International, Inc. (NYSE: MDR), Oceaneering International, Inc. (NYSE: OII), Cameron International Corporation (NYSE: CAM), Pride International, Inc. (NYSE: PDE), Oil States International, Inc. (NYSE: OIS), Rowan Companies, Inc. (NYSE: RDC), and Tidewater Inc. (NYSE: TDW).

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

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, 2011.

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.

Table of Contents

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.

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;
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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). BOEMRE also plans to conduct inspections of each deepwater drilling operation for compliance with BOEMRE'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 Workplace Safety Rule (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. The Department of the Interior has a process underway regarding the establishment of a mechanism relating to the availability of blowout containment resources, and it is expected that this mechanism will be implemented in the near future. It is also expected that the BOEMRE 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 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. Although the moratorium has been lifted, to date no new permits for offshore deepwater drilling have been issued. We can provide no assurance regarding the grant or timing of permits. If permits are not issued or there is a significant delay in issuance, and with respect to our services business, 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.

On June 26, 2009, the U.S. House of Representatives approved adoption of the "American Clean Energy and Security Act of 2009," also known as the "Waxman-Markey Cap-and-Trade legislation," or "ACESA." The purpose of ACESA is to control and reduce emissions of greenhouse gases in the United States. The U.S. Senate has begun work on its own legislation for controlling and reducing emissions of greenhouse gases in the United States. For legislation to become law, both chambers of U.S. Congress would be required to approve identical legislation. It is not possible at this time to predict whether or when the Senate may act on climate change legislation, how any bill approved by the Senate would be reconciled with ACESA, or how federal legislation may be reconciled with state and regional requirements.

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

Additionally, 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 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 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. 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 all or any portion of the oil and gas assets or the production facilities.

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

Our 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, 2010, we had approximately $1.4 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;

Table of Contents

- 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 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.

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.

Table of Contents

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, 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.

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

In addition to the 1,000 shares of preferred stock held by Fletcher International, Ltd. pursuant to the First Amended and Restated Agreement dated January 17, 2003, but effective as of December 31, 2002, by and between Helix and Fletcher International, Ltd., 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;

Table of Contents

- 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 and with our divestiture of Cal Dive, 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.

Table of Contents

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.

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.

If the prices for crude oil and natural gas decrease from current levels, and we have not entered into additional forward sale or financial hedge contracts to stabilize our cash flows, our oil and gas revenues may decrease in 2011 and beyond, perhaps significantly, absent offsetting increases in production amounts.

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 forward sold for future physical delivery a portion of our future production. This means that a portion of our production is sold at a fixed price as a shield against dramatic price declines that could occur in the market. We have hedged a significant portion of our anticipated production for 2011 and some natural gas production for 2012 with swap financial contracts. We may from time to time engage in other hedging activities. These hedging activities may limit our benefit from commodity price increases.

We are vulnerable to risks associated with the Gulf of Mexico because we currently operate 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 one field, Bushwood located at Garden Banks Blocks 462, 463, 506 and 507, that represents approximately 36% of our total estimated proved reserves as of December 31, 2010. If the proved reserves at Bushwood 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. Separately, without Bushwood's future reserve potential, the value that we may be able to realize in any potential disposition of our oil and gas business would likely be significantly diminished. In February 2011, our average daily production from the Phoenix field located at Green Canyon Blocks 236, 237, 238 and 282 was approximately 9,500 barrels of oil and 15 MMcf of natural gas (or approximately 72 MMcfe per day), net to our interest, which represents approximately 57% of our daily oil production and 45% of our daily total production for the month. 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, 2010 and 2009, 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.

Approximately 81% 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, 2010, approximately 17% of our total estimated proved reserves were PDNP, 4% were PDSI and approximately 61% 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 81% of our proved reserves at December 31, 2010 are PUD, PDSI and PDNP. Further, our proved producing reserves at December 31, 2010 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

Table of Contents

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.

We own a fleet of seven vessels and 38 ROVs, five trenchers, and two ROV Drills. We also lease four vessels and one ROV. Currently all of our vessels, both owned and leased, have DP capabilities specifically designed to respond to the deepwater market requirements. Two of our vessels have built-in saturation diving systems.

DIVESTITURES

In 2008, we sold a 30% working interest in the Bushwood discoveries (Garden Banks Blocks 462,463, 506 and 507) and other Outer Continental Shelf oil and gas properties (East Cameron Blocks 371 and 381), to affiliates of a private independent oil and gas company for total cash consideration of approximately $183.4 million (which included the purchasers' share of incurred capital expenditures on these fields), and additional potential cash payments of up to $20 million contingent on exceeding specified field production milestones. The co-owners also pay their pro rata share of all capital expenditures related to the exploration, development and decommissioning of these fields. Future asset retirement costs will be shared on a pro rata share basis between the co-owners and us. Proceeds from the sale of these properties were used to partially repay our outstanding revolving loans in April 2008. As a result of these sales, we recognized a pre-tax gain of $91.6 million in the first half of 2008.

In May 2008, we sold all our interests in our onshore proved and unproved oil and gas properties located in the states of Texas, Mississippi, Louisiana, New Mexico and Wyoming ("Onshore Properties") to an unrelated third party. We sold these Onshore Properties for cash proceeds of $47.3 million and recorded a related loss of $11.9 million in the second quarter of 2008. Proceeds from the sale of these properties were used to reduce our outstanding revolving loans in May 2008. Included in the cost basis of the Onshore Properties was $8.1 million of allocated goodwill from our Oil and Gas segment.

In December 2008, we announced the sale of all our interests in the Bass Lite field (Atwater Block 426), a 17.5% working interest, to our joint interest owners in the field for approximately $49 million.   Proceeds from the sale were used to fund our working capital requirements.

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

Table of Contents

- Approximately $25 million from the sale of six 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 two separate public secondary offerings 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

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)(4)	Vanuatu	5/2010	482	220	—	DP	300 and 36
Express (4)	Vanuatu	8/2005	531	132	—	DP	396 and 150
Intrepid (4)	Bahamas	8/1997	381	89	Capable	DP	400
Floating Production Unit —							
Helix Producer I (5)	Bahamas	4/2009	528	95	—	DP	26 and 26
Well Operations —							
Q4000 (6)	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 (7)	Norway	11/2008	385	120	Capable	DP	250
Robotics —							
39 ROVs, 5 Trenchers and 2 ROVDrills (4), (8) (9)	—	Various	—	—	—	—	—
Olympic Canyon (9)	Norway	4/2006	304	87	—	DP	150
Olympic Triton (9)	Norway	11/2007	311	87	—	DP	150
Island Pioneer (9)	Vanuatu	5/2008	312	110	—	DP	140

(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) Conversion of vessel commenced in 2007. The vessel was placed into service in our fleet in May 2010.

(4) Subject to vessel mortgages (US ROVs and trenchers only) securing our Senior Credit Facilities described in Note 9

(5) 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 Senior Credit Facilities (Note 9).

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

(7) Leased by Clough Helix Joint Venture, in we which maintain a 50% ownership interest – Note 7

(8) Average age of our fleet of ROVs, trenchers and ROV Drills is approximately 5.1 years.

(9) Leased. One ROV is leased, we own the remaining 38 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, 2010, 2009 and 2008:

Table of Contents

	Year Ended December 31,		
	2010	2009	2008
Contracting Services:			
Pipelay and robotics support	84%	79%	92%
Well operations	83%	82%	70%
ROVs	62%	68%	73%

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 previously untapped eastern Gulf of Mexico. First production began in July 2007. The Independence Hub facility is capable of processing up to 1 billion cubic feet (Bcf) per day of gas.

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 70 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 of Mexico oil spill response and containment efforts (Note 1). Following these services, the HP I returned to the Phoenix field, where production commenced on October 19, 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

In December 2008, the SEC announced that it had approved revisions designed to modernize the oil and gas company reserve reporting requirements. In January 2010, the Financial Accounting Standards Board ("FASB") issued

Accounting Standards Update 2010-03 “Oil and Gas Reserve Estimation and Disclosures.” We adopted these rules on December 31, 2009 in conjunction with our year-end 2009 proved reserve estimates and implemented the mandated authoritative guidance issued by the FASB on extractive activities for oil and gas reserve estimation and disclosures requirements. The objective of this guidance was to align the oil and gas reserve estimation and disclosure requirements with the requirements of the SEC. The most significant amendments to the requirements included the following:

*Commodity prices - estimates of proved reserves and related discounted cash flows are now based on an average twelve month commodity price based on the price of oil and gas on the first day of each month for the year the reserve report relates;
*Disclosure of Unproved Reserves - Probable and Possible reserves may be disclosed separately from proved reserves on a voluntary basis. We elected not to disclose Probable and Possible reserves;
*Proved Undeveloped Reserve Guidelines – Reserves maybe classified as proved undeveloped reserves if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless specific circumstances justify a longer time;
*Reserves Estimation Using New Techniques – Reserves may be estimated through a use of reliable techniques in addition to traditional flow test and production history;
*Reserves Personnel and Estimation Process – Additional disclosure is required regarding the qualifications of the chief technical person who oversees the reserve estimation process and/or the independence of the preparer of our estimated proved reserves. We must also disclose our significant internal controls over the reserve estimation process;
*Disclosure by Geographic Area – Reserves in foreign countries must be presented separately if such reserves represent more than 15% of our total estimated oil and gas proved reserves; and
*Non Traditional Resources – The definition of oil and gas producing activities has been expanded to include other marketable products.

One effect of adoption of these rules included the application of a lower oil price at December 31, 2010 (representing the average price for the year $77.55 per barrel) than what would have been used under the previous rule (year end price of $91.38 per barrel). At December 31, 2009, the requirement to use an average price for both oil and natural gas ($58.05 per barrel and $3.72 per mmbtu) caused such prices to be significantly lower than those in effect at December 31, 2009 ($79.36 per barrel and $5.79 per mmbtu). Reduced prices for oil and natural gas generally result in lower estimates of proved reserves. Other than these price differences, adoption of these new regulations had little effect on our estimates of reserves at both December 31, 2010 and 2009; however, the rule requiring development of proved undeveloped reserves within five years 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 Vice President – Reservoir Engineering.

Our Vice President – Reservoir Engineering prepares all reserve estimates covering all of our oil and gas properties. Our Vice President – Reservoir Engineering is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Our Vice President – Reservoir Engineering has a Bachelor of Science degree in Engineering and over 15 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 (82 fields as of December 31, 2010). We consider any field to be significant if its estimated discounted future net revenues represent 1% or more than our total estimated discounted future net revenues from all of our fields.

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 at both December 31, 2010 and December 31, 2009. Their proved reserve estimates are included herein as Exhibit 99.1 to this Annual Report. The same independent reservoir engineer firm audited substantially all of our estimates of proved reserves at December 31, 2008. See Note 19 for information regarding the independent petroleum engineer's audit of our proved reserve estimates at December 31, 2008.

The table below sets forth the approximate estimate of our proved reserves as of December 31, 2010. 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.

	As of December 31, 2010		
	Proved Developed Reserves	Proved Undeveloped Reserves	Total Proved Reserves
Gas (Bcf)	76	151	227
Oil (MMBbls)	12	13	25
Total (Bcfe)	146	230	376

Proved Undeveloped Reserves (“PUDs”)

At December 31, 2010, our PUDs totaled 151 Bcf of natural gas and 13 MMBbls of crude oil for a total of 230 Bcfe. Our PUDs represent approximately 61% of our total estimates of proved oil and natural gas reserves at December 31, 2010. At December 31, 2009 our estimated PUD reserves totaled 364 Bcfe. 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.

Our most substantial PUDs are located at our Bushwood field (see “Significant Oil and Gas Properties” below). Our Bushwood field has estimated PUDs totaling approximately 109 Bcfe representing approximately 47% of all our estimated PUD reserves and 29% of our total estimated proved reserves. In June 2010, in connection with our regular mid-year proved reserve review, we had substantial reductions in our PUD reserve estimates, including a 91 Bcfe reduction in our estimated Bushwood field PUD reserves primarily reflecting well performance issues with our Noonan gas wells. Separately, we also eliminated the approximate 12 Bcfe of estimate PUD reserves related to our one United Kingdom property following our decision that we would no longer seek to further develop the field. In 2010, we developed approximate 3.9 Bcfe of PUD reserves at our Gunnison field. See Note 5 for additional information regarding our mid-year 2010 estimated proved reserves and our intention to abandon our United Kingdom property in accordance with applicable United Kingdom regulations.

Costs incurred to develop PUDs totaled $40.1 million in 2010, $53.2 million in 2009 and $154.4 million in 2008. 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 $302.9 million at December 31, 2010.

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, 2010, our exploration, development and production operations were located exclusively in the United States located offshore in the Gulf of Mexico. We have one inactive field, known as Camelot, located in the North Sea. We plan to abandon the Camelot field in accordance with applicable United Kingdom regulations during 2011.

All of our production during 2010 and the 376 Bcfe of total estimated proved reserves at December 31, 2010 (approximately 81% 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, 2010:

Table of Contents

	Development Location	Net Total Proved Reserves (Bcfe)	Net Proved Reserves Mix Oil %	Gas %	2010 Net Production (Bcfe)	Average WI%	Expected First Production
Deepwater							
Bushwood(1)	U.S. GOM	137	6	94	20	51	Producing
Phoenix(2)	U.S. GOM	44	77	23	3	70	Producing
Gunnison(3)	U.S. GOM	24	64	36	4	19	Producing
Jake (4)	U.S. GOM	5	23	77	-	25	PUD 2011
Outer Continental Shelf							
East Cameron 346	U.S. GOM	34	80	20	1	75	Producing
South Timbalier 86/63	U.S. GOM	25	42	58	3	91	Producing
South Pass 89	U.S. GOM	22	39	61	1	27	Producing
High Island A557	U.S. GOM	17	67	33	2	100	Producing
South Marsh Island 130	U.S. GOM	11	77	23	2	100	Producing
West Cameron 170	U.S. GOM	10	30	70	1	55	Producing
Ship Shoal 223/224	U.S. GOM	9	38	62	2	51	Producing
Eugene Island 302	U.S. GOM	7	82	18	-	100	PUD 2011

(1) Garden Banks Blocks 462, 463, 506 and 507 (formerly called Noonan/Danny). 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.

(4) Green Canyon Block 490. Field is currently being developed and we expect initial production in 2011.

United States Offshore

Deepwater

The estimated proved reserves associated with our four fields in the Deepwater of the Gulf of Mexico totaled approximately 210 Bcfe or approximately 56% of our total estimated proved reserves at December 31, 2010. We are the operator in fields representing approximately 57% of our Deepwater proved reserves (approximately 32% of total proved reserves). We operate the Phoenix field and certain portions of the Bushwood field. Gunnison, a non-operated field, has been producing since December 2003. In 2009, we participated in the discovery at the Jake Prospect, which is expected to be developed and commence production in 2011. Our net production from our Deepwater properties totaled approximately 26.9 Bcfe in 2010 as compared to 12.3 Bcfe in 2009. The increased production reflects further development of the Bushwood field in early 2010 and the commencement of production from the Phoenix field in October 2010.

Outer Continental Shelf

Our estimated proved reserves for our 78 fields in the Gulf of Mexico on the OCS totaled approximately 166 Bcfe or 44% of our total estimated proved reserves as of December 31, 2010. Our net production from the OCS properties totaled approximately 20.3 Bcfe in 2010 and 31.3 Bcfe in 2009. Our largest field on the OCS is East Cameron Block 346, the total estimated proved reserves of which represents approximately 20% of our aggregated OCS estimated proved reserves (or approximately 9% of total estimated proved reserves). Only two other individual OCS fields represented over 5% of our total estimated proved reserves. The South Timbalier Blocks 86/63 field represented approximately 15% of our total estimated OCS proved reserves (or approximately 7% of our total estimated proved reserves) and the South Pass Block 89 field representing approximately 13% of total OCS proved reserves (approximately 6% of total estimated proved reserves). We are the operator of 76% of our OCS properties the composite estimated proved reserves of which totals approximately 127 Bcfe.

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 $12 million). During 2011, we plan to abandon the Camelot field in accordance with the applicable U.K. regulations. The results of our U.K. operations were immaterial for each of the three years ended December 31, 2010, 2009 and 2008, 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,		
	2010	2009	2008
Production:			
Gas (Bcf)	27	27	31
Oil (MMBbls)	3	3	3
Total (Bcfe)	47	44	47
Average sales prices realized (including hedges):			
Gas (per Mcf)	$ 6.01	$ 4.48	$ 9.29
Oil (per Bbl)	$ 75.27	$ 67.11	$ 92.22
Total (per Mcfe)	$ 8.80	$ 7.00	$ 11.43
Average production cost per Mcfe	$ 2.88	$ 2.74	$ 2.60
Average depletion and amortization per Mcfe	$ 4.98	$ 3.87	$ 4.21

Productive Wells

The number of productive oil and gas wells in which we held interests as of December 31, 2010 is as follows:

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
United States – Offshore	255	202	265	136	520	338

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

The following table summarizes non-producing wells and wells with multiple completions as of December 31, 2010:

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Not producing (shut-in)	53	36	132	76	185	112
Multiple completions	16	7	45	19	61	26

Developed and Undeveloped Acreage

The developed and undeveloped acreage (including both leases and concessions) that we held at December 31, 2010 is as follows:

	Undeveloped		Developed	
	Gross	Net	Gross	Net
United States – Offshore	167,260	145,132	413,526	235,214
United Kingdom – Offshore	25,406	25,406	9,778	9,778
Total	192,666	170,538	423,304	244,992

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
2011	30,872	24,872
2012	27,275	21,515
2013	30,760	30,760
2014	5,760	5,760
2015	5,760	5,760
2016 and beyond	66,833	56,465
Total	167,260	145,132

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, 2010, 2009 and 2008:

	Net Exploratory Wells			Net Development Wells		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2010	—	—	—	1.0	—	1.0
Year ended December 31, 2009	0.3	—	0.3	—	—	—
Year ended December 31, 2008	0.4	0.6	1.0	2.4	—	2.4

No wells were drilled in the United Kingdom in 2010, 2009 or 2008. We did not have any in progress wells at December 31, 2010.

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	25,000 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 Corporate Offices and Operations	3.9 acres (Building: 42,463 square feet)
	Canyon Offshore Limited Corporate Offices, Operations and Sales Office	
	Energy Resource Technology (U.K). Limited Corporate Offices	

Perth, Australia	Well Ops SEA Pty Ltd Corporate Offices	1.0 acre (Building: 12,040 square feet)
	Helix Energy Services Pty Ltd. Corporate Offices	
Rotterdam, The Netherlands	Helix Energy Solutions BV Corporate Offices	21,600 square feet
Singapore	Canyon Offshore International Corp Corporate, Operations and Sales	22,486 square feet
	Helix Offshore Crewing Service Pte. Ltd. Corporate Headquarters	

Table of Contents

Item 3. Legal Proceedings.

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 a counterclaim that in the aggregate approximated $12 million U.S. dollars. On March 30, 2010, an out of court settlement of these claims was reached. Under terms of the settlement, in April 2010 we paid the third party $15 million AUD to settle all its 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 2010 included 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 charges were recorded as a component of our selling, general and administrative expenses.

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	56	President and Chief Executive Officer and Director
Johnny Edwards	57	Executive Vice President — Oil & Gas
Anthony Tripodo	58	Executive Vice President and Chief Financial Officer
Alisa B. Johnson	53	Executive Vice President, General Counsel and Corporate Secretary
Lloyd A. Hajdik	45	Senior Vice President — Finance and Chief Accounting Officer

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

Table of Contents

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, production facilities and corporate planning functions. Mr. Tripodo was a director of Helix from February 2003 until June 2008. Prior to joining Helix, Mr. Tripodo was the Executive Vice President and Chief Financial Officer of Tesco Corporation. From 2003 through the end of 2006, he was a Managing Director of Arch Creek Advisors LLC, a Houston based investment banking firm. From 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 approximately 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.

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
2009		
First Quarter	$ 9.47	$ 2.21
Second Quarter	$ 12.65	$ 4.80
Third Quarter	$ 16.11	$ 8.76
Fourth Quarter	$ 16.92	$ 10.79
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(1)	$ 14.74	$ 10.92

(1) Through February 22, 2011

Table of Contents

On February 18, 2011, the closing sale price of our common stock on the NYSE was $14.35 per share. As of February 18, 2011, there were an estimated 349 registered shareholders and 23,835 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, 2004 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: Global Industries, Ltd., Oceaneering International, Inc., Cameron International Corporation, Pride International, Inc., Oil States International, Inc., FMC Technologies, Inc., McDermott International, Inc., Rowan Companies, Inc., Tidewater Inc., ATP Oil & Gas Corporation, W&T Offshore, Inc. and Energy XXI (Bermuda) Limited. 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, 2010 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, 2005 in our common stock at the closing price on that date price and on December 31, 2005 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 — (66.2%); the Peer Group — 71.8%; the OSX — 34.6%; and S&P 500- 0.8%. These results are not necessarily indicative of future performance.

Table of Contents

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

	As of December 31,					
	2005	2006	2007	2008	2009	2010
Helix	$ 100.0	$ 87.4	$ 115.6	$ 20.2	$ 32.7	$ 33.8
Peer Group Index	$ 100.0	$ 116.2	$ 172.3	$ 65.8	$ 128.1	$ 171.8
Oil Service Index	$ 100.0	$ 109.8	$ 165.6	$ 66.7	$ 107.0	$ 134.6
S&P 500	$ 100.0	$ 113.6	$ 117.6	$ 72.4	$ 89.3	$ 100.8

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, 2010	1,439	$ 12.30		
November 1 to November 30, 2010				
December 1 to December 31, 2010	265	13.20		
	1,704	$ 12.44		

(1) Represents shares delivered to the Company by employees in satisfaction of minimum withholding taxes and upon forfeiture of restricted shares.

(2) Shares repurchased under previously announced stock buyback program (Note 14). In July 2010, we repurchased the remaining available shares under stock buyback program. Additional shares became available under the stock buyback program in January 2011 (see footnote (3) below).

(3) Amount as of December 31, 2010. In January 2011, we issued approximately 0.5 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, 2010, 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, 2010				
2010	2009 (1)	2008	2007	2006
(amounts in thousands, except per share data)				

Net revenues	$ 1,199, 838	$1,461,687	$2,114,074	$1,732,420	$1,328,136
Gross profit	33,672	243,162	372,191	505,907	503,478
Operating income (loss) (2)	(94,656)	203,815	(414,222)	411,279	392,061
Equity in earnings of investments	19,469	32,329	31,854	19,573	17,927
Income (loss) from continuing operations	) (124,109	166,170	(580,245)	343,639	338,816
Income (loss) from discontinued operations, net of taxes	) (44	9,581	(9,812)	1,347	4,806
Net income (loss), including noncontrolling interests(3)	) (124,153	175,751	(590,057)	344,986	343,622
Net (income) loss applicable to noncontrolling interests	(2,835)	(19,697)	(45,873)	(29,288)	(725)
Net income (loss) applicable to Helix	) (126,988	156,054	(635,930)	315,698	342,897
Preferred stock dividends and accretion	) (114	(54,187)4	(3,192)	(3,716)	(3,358)
Net income (loss) applicable to Helix common shareholders	(127,102)	101,867	(639,122)	311,982	339,539
Adjusted EBITDAX, less Cal Dive (5)	$ 430,326	$ 490,092	$ 575,272	$ 608,813	$ 447,565

40

Table of Contents

	Year Ended December 31, 2010				
	2010	2009 (1)	2008	2007	2006
	(amounts in thousands, except per share data)				
Basic earnings (loss) per share of common stock :					
Continuing operations	$ (1.22)	0.92	$ (6.94)	$ 3.40	$ 3.92
Discontinued operations		0.09	(0.11)	0.02	0.06
Net income (loss) per common share	$ (1.22)	$ 1.01	$ (7.05)	$ 3.42	$ 3.98
Diluted earnings (loss) per share of common stock :					
Continuing operations	$ (1.22)	$ 0.87	$ (6.94)	$ 3.25	$ 3.74
Discontinued operations		0.09	(0.11)	0.01	0.05
Net income (loss) per common share	$ (1.22)	$ 0.96	$ (7.05)	$ 3.26	$ 3.79
Weighted average common shares outstanding:					
Basic	103,857	99,136	90,650	90,086	84,613
Diluted	103,857	105,720	90,650	95,647	89,714

(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) Total oil and gas property impairment charges totaled $181.1 million, $120.6 million, $920.0 million and $64.1 million for each of the years ending December 31, 2010, 2009, 2008, and 2007, respectively. There were no impairments in 2006. Our impairments in 2008 included $896.9 million of impairment charges to reduce goodwill ($704.3 million) and certain oil and gas properties ($192.6 million) to their estimated fair value in fourth quarter of 2008. Also includes exploration expenses totaling $8.3 million in 2010 and $24.4 million in 2009, $32.9 million in 2008, $26.7 million in 2007, and $43.1 million in 2006.

(3) Includes $77.3 million of gains on the sales of Cal Dive common stock held by us in 2009. Also includes the impact of gains on subsidiary equity transactions of $98.5 million and $96.5 million for the year ended December 31, 2007 and 2006, respectively. The gains were derived from the difference in the value of our investment in CDI immediately before and after its issuance of stock related to its acquisition of Horizon and its initial public offering. See Note 3 for additional information related to our transactions involving Cal Dive common stock.

(4) 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,				
	2010	2009 (1)	2008(2)	2007	2006
	(In thousands)				
Working capital	$ 373,057	$ 197,072	$ 287,225	$ 48,290	$ 310,524
Total assets	3,952,020	3,779,533	5,067,066(2)	5,449,515	4,287,783
Long-term debt and capital leases (including current maturities)	1,357,932	1,360,739	2,027,226	1,758,186	1,431,235
Convertible preferred stock	1,000(3)	6,000(3)	55,000	55,000	55,000
Total controlling interest shareholders' equity	1,260,604	1,405,257	1,191,149(2)	1,829,951	1,556,314
Noncontrolling interests	25,040	22,205	322,627	263,926	59,802
Total equity	1,285,644	1,427,462	1,513,776	2,093,877	1,616,116(

(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 in fourth quarter to reduce goodwill, intangible assets with indefinite lives and certain oil and gas properties to their estimated fair values (Note 2).

(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 commons 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).

(4) Total equity amount includes a January 1, 2006 $34.9 million cumulative effect on change of accounting principle to reflect the adoption of ASC Topic No. 470-20.

Table of Contents

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 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 operating 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 covenant requirements. We believe our measure of EBITDAX provides useful information to the public regarding our ability to service debt and fund capital expenditures and it may help our investors understand our operating performance and make it easier 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) from continuing operations we provide amounts as reflected in our accompanying consolidated financial statements, unless otherwise footnoted. This means such amounts are at 100% even if we do not own 100% of all of our subsidiaries, most notably Cal Dive. 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. Lastly, we include a separate line to remove Cal Dive completely from our Adjusted EBITDAX amounts to provide a meaningful comparison of our current and historical operating performance without Cal Dive, which we deconsolidated in June 2009 (Note 3).

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 to GAAP, it should not be considered in isolation or as a substitute for net income (loss) attributable to common shareholders 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, 2010				
	2010	2009	2008	2007	2006
	(amounts in thousands)				
Income (loss) from continuing operations	$ (124,109)	$ 166,170	$ (580,245)	$ 343,639	$ 338,816
Adjustments:					
Income tax provision (benefit)	(39,598)	95,822	86,779	171,862	252,753
Net interest expense	86,280	51,495	111,098	67,047	41,554
	317,116	262,617	333,726	329,798	191,705

Depreciation, depletion and amortization expense					
Asset impairment charges	197,826	121,855	919,986	75,8651	
Exploration expenses	8,276	24,383	32,926	26,725	43,115
EBITDAX	445,791	722,342	904,270	1,014,936	867,943
Adjustments:					
Non-controlling interest in Cal Dive		(44,785)	(105,280)	(61,404)	
Non-controlling interest in Kommandor LLC	(3,878)	(3,344)	102	(82)	
Discontinued operations(2)	(16)	(290)	3,242	3,696	8,730
Gain (loss) on sales of assets	(7,165)	(79,362)	(73,471)	(202,064)	(225,951)
Asset impairments charges	(4,406)	(48,178)	(13,031)		
ADJUSTED EBITDAX	$ 430,326	$ 546,383	$ 715,832	$ 755,082	$ 650,722

Table of Contents

ADJUSTED EBITDAX	$ 430,326	$ 546,383	$ 715,832	$ 755,082	$ 650,722
Less Cal Dive, net of non-controlling interests		(56,291)	(140,560)	(146,269)	(203,157)
ADJUSTED EBITDAX less Cal Dive	$ 430,326	$ 490,092	$ 575,272	$ 608,813	$ 447,565

1. Includes the $11.8 million related to Cal Dive's impairment of an equity investment in Offshore Technology Solutions Limited.
2. Amounts associated with are Helix RDS operations that we sold in April 2009 (Note 1).

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 two years, we have focused on improving our balance sheet by increasing our liquidity through dispositions of our non-core business assets as well as reductions in planned capital spending. Since the beginning of 2009, dispositions of non-core business assets resulted in receipt of the following pre-tax proceeds:

- Approximately $25 million from the sale of six 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 two separate public secondary offerings 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.

In March 2010, we announced the engagement of advisors to assist us with evaluating potential alternatives for the disposition of our oil and gas business. At the time of the filing of this Annual Report, we do not have an approved or definitive plan for the disposition of our oil and gas business. We are unable to be specific regarding a timetable for any disposition, the completion of which will be largely dependent on the evolving economic and financial market conditions as well as regulatory developments with respect to the Gulf of Mexico oil and gas 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 deploy capital 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 will often lag drilling operations by a period ranging from 6 to 18 months, meaning that even if there were a sudden surge in deepwater drilling in the Gulf of Mexico it probably would still be some time before we would start servicing 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

Table of Contents

conditions, hydrocarbon production and excess capacity, geopolitical issues, weather and several other factors, including but not limited to:

- worldwide economic activity, including available access to global capital and capital markets;
- demand for oil and natural gas, especially in the United States, Europe, China and India;
- economic and political conditions in the Middle East and other oil-producing regions;
- the effect of new regulations on offshore Gulf of Mexico oil and gas operations;
- 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 policies.

The NYMEX West Texas Intermediate crude oil price has averaged $79.53 per barrel in 2010. Although this price level is generally favorable to support potential additional capital investment in exploration and development activities, this price remains significantly lower than the historical high prices realized in mid-to-late 2008. The NYMEX Henry Hub natural gas price began 2010 with prices approximating $6.00 per Mmbtu; however the price has since decreased to the current approximate range of $4.00 to $4.50 per Mmbtu. Prices for natural gas are near decade lows and reflect 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. Although there have been signs that the economy is improving, most economists believe the recovery will be slow and may take years to recover to levels previously achieved. 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 more recently the 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 May 2010, the U.S. Department of Interior ("DOI") announced a total moratorium on new drilling in the Gulf of Mexico. This moratorium also affected 33 in progress deepwater wells. The moratorium on drilling in the shallow water of the Gulf, defined as water depths less than 500 feet, was lifted in late May 2010. However, the DOI also announced its intention to extend the drilling moratorium on deepwater wells through November 2010. On October 12, 2010, the DOI lifted the 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. Although some of the in progress deepwater wells have been repermitted, no new deepwater drilling permits have been issued since the lifting of the drilling moratorium and relatively few shallow water drilling permits have been issued since its ban was lifted in May 2010.

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

Table of Contents

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, 2010, we had cash on hand of $391.1 million and $396.2 million available for borrowing under our revolving credit facilities. Our capital expenditures for 2011 are expected to total approximately $225 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

Over the last few years we have continued to evolve our model by completing a variety of transactions and actions 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 the July 2006 acquisition of Remington Oil & 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 from additional borrowings under the Cal Dive revolving credit facility.

During 2006 we committed to four capital projects that have expanded and will continue to significantly 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 and 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.

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%.

Table of Contents

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 transactions which was recorded as a component of “Gain (loss) on investment in Cal Dive common stock” in the accompanying consolidated statement of operations.

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 continuing 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 and 2008 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.

Contracting Services Operations

We seek to provide services and methodologies that we believe are critical to finding and developing offshore reservoirs and maximizing production economics. The Contracting Services segment includes our subsea construction, well operations and robotics 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, 2010, our contracting services operations had backlog of approximately $267.3 million, including $218.8 million expected to be perform in 2011. At December 31, 2009, our backlog totaled $251.0 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

In 1992 we began our oil and gas operations to provide a more efficient solution to offshore abandonment, to expand our off-season utilization of our contracting services assets, and to achieve incremental returns. 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

Table of Contents

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 condensed consolidated financial statements (Note 1). 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, 2010 and 2009

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

	Year Ended December 31,		Increase/
	2010	2009	(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) Represented by 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) Included asset impairment charges of oil and gas properties totaling $181.1 million in 2010 and $120.6 million in 2009. These impairments charges included $9.2 million and $55.9 million recorded in the respective fourth quarter periods of 2010 and 2009. These amounts also include exploration expenses totaling $8.3 million in 2010 and $24.4 million in 2009, which primarily reflects 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. Our well operations vessels count in 2010 includes one chartered vessel by our Australian joint venture (Note 7).

Table of Contents

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, 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(1)	—	7,865	(7,865)
	$ 123,170	$ 127,913	$ (4,743)

(1) Represented by 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).

Intercompany segment profit during the years ended December 31, 2010 and 2009 were 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(1)	—	365	(365)
	$ 19,112	$ 13,454	$ 5,658

(1) Represented by 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).

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 plug the wells and remove the structures from this field in 2011 in accordance with the applicable U.K. regulations. We had no revenue associated with our U.K. oil and gas operations in 2010. 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

Table of Contents

	Year Ended December 31, 2010	2009	Increase/ (Decrease)
Gas production volumes(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 (MMcfe)	47,221	43,782	3,439
Price per Mcfe	$ 8.80	$ 7.00	$ 1.80
Oil and gas revenue information (in thousands)-			
Oil and gas sales revenue	$ 415,364	$ 306,308	$ 109,056
	$ 10,005	$ 79,030	$ (69,025

(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.

Presenting the expenses of our Oil and Gas segment on a cost per Mcfe 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 Mcfe of production basis (barrels of oil converted to Mcfe at a ratio of one barrel to six Mcf):

	Year Ended December 31, 2010 Total	Per Mcfe	2009 Total	Per Mcfe
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$87,688	$1.86	$78,348	$1.79
Workover (3)	23,156	0.49	9,790	0.22
Transportation	6,924	0.15	8,209	0.19
Repairs and maintenance	8,033	0.17	13,469	0.31
Overhead and company labor	9,884	0.21	10,020	0.23
Sub Total	$135,685	$2.88	$119,836	$2.74
Depletion and amortization	$219,773	$4.65	$154,052	$3.52
Abandonment	1,050	0.02	4,369	0.10
Accretion	15,517	0.33	15,204	0.35

Impairments (4)	181,083	3.83	69,038	1.58
Net hurricane (reimbursements) costs (5)	4,699	0.10	(23,332)	(0.53)
	422,122	8.93	219,331	5.02
Total	$557,807	$11.81	$339,167	$7.76

(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.