HELIX ENERGY SOLUTIONS GROUP INC
Form 10-K
March 02, 2009

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

Form 10-K

(Mark One)

R	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
	For the fiscal year ended December 31, 2008
	or
£	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) of the Securities Exchange Act of 1934
	For the transition period from to

Commission File Number 001-32936

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

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

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

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

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

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

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

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

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

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

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant based on the last reported sales price of the Registrant's Common Stock on June 30, 2008 was approximately $3.6 billion.

The number of shares of the registrant's Common Stock outstanding as of February 27, 2009 was 98,386,640.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement for the Annual Meeting of Shareholders to be held on May 13, 2009, are incorporated by reference into Part III hereof.

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

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 "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 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 that our proposed vessels, when completed, will have certain characteristics or the effectiveness of such characteristics;

- 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 the 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;
- uncertainties regarding our ability to replace depletion;
- unexpected future capital expenditures (including the amount and nature thereof);
- impact of oil and gas price fluctuations and the cyclical nature of the oil and gas industry;
- 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 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 19 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. (“Helix”) is an international offshore energy company, incorporated in the state of Minnesota in 1979, that provides reservoir development solutions and other contracting services to the energy market as well as to our own oil and gas properties. Our Contracting Services segment utilizes our vessels, offshore equipment and proprietary technologies to deliver services that may reduce finding and development (“F&D”) costs and encompass the complete lifecycle of an offshore oil and gas field. Our Oil and Gas segment engages in prospect generation, exploration, development and production activities. Our primary operations are located in the Gulf of Mexico, North Sea, Asia Pacific and Middle East regions. Unless the context indicates otherwise, as used in this Annual Report, the terms “Company,” “we,” “us” and “our” refer collectively to Helix and its subsidiaries, including Cal Dive International, Inc. (collectively with its subsidiaries referred to as “Cal Dive” or “CDI”), a publicly traded majority-owned subsidiary.

In December 2008, we announced the intention to focus and shape the future of the Company around our deepwater construction and well intervention services. For additional information regarding this recent strategy announcement and about our deepwater construction and well intervention services see sections titled “Industry and Our

Strategy," "Contracting Services" 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" and Cal Dive's common stock also trades on the NYSE under the ticker symbol "DVR". Our Chief Executive Officer submitted the annual CEO certification to the NYSE as required under the its listed Company Manual in April 2008. 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 report.

Please refer to the subsection "— Certain Definitions" on page 8 for definitions of additional terms commonly used in this Annual Report.

CONTRACTING SERVICES

We seek to provide services and methodologies which we believe are critical to finding and developing offshore reservoirs and maximizing production economics, particularly from marginal fields. By “marginal,” we mean reservoirs that are no longer wanted by major operators or are considered too small to be material to them. Our “life of field” services are organized in five disciplines: construction, well operations, reservoir and well technology services, drilling, and production facilities. We have disaggregated our contracting services operations into three reportable segments in accordance with Financial Accounting Standards Board (“FASB”) Statement No. 131 Disclosures about Segments of an Enterprise and Related Information (“SFAS No. 131”): Contracting Services (which includes subsea construction, well operations, reservoir and well technology services and drilling); Shelf Contracting; and Production Facilities.

Construction

For over 30 years, we have supported offshore oil and natural gas infrastructure projects by providing our services, which include the construction and maintenance of pipelines, production platforms, risers and subsea production systems primarily in the Gulf of Mexico, North Sea, Asia Pacific and Middle East regions. Our subsea construction services include pipelay and robotics in water depths exceeding 1,000 feet. We also provide construction services periodically from our well intervention vessels. We perform traditional subsea services, including air and saturation diving, salvage work and shallow water pipelay on the Outer Continental Shelf (“OCS”) of the Gulf of Mexico in water depths up to 1,000 feet through Cal Dive, a majority-owned subsidiary in which we currently own approximately 51%. The financial results of Cal Dive are consolidated in our accompanying financial statements as of December 31, 2008 and 2007 and for each of the years in the three-year period ending December 31, 2008 (see Item 8. Financial Statements and Supplementary Data”).

Well Operations

We engineer, manage and conduct well construction, intervention and decommissioning operations in water depths ranging from 200 to 10,000 feet. Over the long term, we expect an increased demand for these services caused by the growing number of subsea tree installations, coupled with our lower cost solutions as compared to a deepwater rig. Accordingly, we are constructing a newbuild vessel (the “Well Enhancer”) and have expanded geographically in Australia and Asia in 2007 with the acquisition of Seatrac Pty Ltd. (“Seatrac”), an established Australian well operations company now called Well Ops SEA Pty Limited (“WOSEA”).

Reservoir and Well Technology Services

Our ownership of Helix RDS Limited (“Helix RDS”) makes us one of the largest outsource providers of sub-surface technology skills in the North Sea. With a staff base of over 120 employees, we have the resources to provide valuable well enhancement services, which typically increase production or extend the life of a reservoir, to our own oil and natural gas projects as well as to our clients. Each team we assign to a specific client comprises a diverse set of skills, including reservoir engineering, geology, modeling, flow assurance, completions, well design and production enhancement. Helix RDS has an established market presence in regions that we have identified as strategically important to future growth, including offices in Aberdeen and London in the United Kingdom, Kuala Lumpur, Malaysia and Perth, Australia.

Drilling

Contract drilling is a service we have not historically provided but have been contemplating since the construction of our Q4000 vessel over eight years ago. We added drilling capability to the Q4000 in 2008. The fundamentals for deepwater rigs have been favorable in recent years, reflecting significant demand and a limited availability of such rigs. Although the deterioration in the worldwide capital markets has led a number of oil and gas companies to recently curtail or to announce anticipated reductions in their near-term capital expenditure budgets, we believe that the long-term deepwater projects will be less affected because of the significant oil and gas reserves associated with such projects and the relatively long lead times required to develop these fields for production. The drilling and completion cost of a subsea development can be as much as 50% of the total F&D costs for a deepwater prospect. The Q4000's drilling capability primarily focuses on the use of hybrid slim-bore technology capable of drilling and completing 6-inch slimbore wells to 22,000 feet total depth and operating in up to 6,000 feet of water, which will allow us to drill many of our own deepwater prospects and support the exploration and appraisal efforts of our clients. We expect approval from the MMS in 2009 for cased well services, including completions, and approval for drilling once we have satisfied MMS requirements.

Production Facilities

We own interests in certain production facilities in hub locations where there is potential for significant subsea tieback activity. Ownership of production facilities enables us to earn a transmission company type return through tariff charges while providing construction work for our vessels. We own a 50% interest in the Marco Polo tension leg platform ("TLP"), which was installed in 4,300 feet of water in the Gulf of Mexico, through Deepwater Gateway, L.L.C. ("Deepwater Gateway"). We also own a 20% interest in Independence Hub, L.L.C. ("Independence Hub"), an affiliate of Enterprise Products Partners L.P. Independence Hub owns a 105-foot deep draft, semi-submersible platform, which was installed during 2007. The Independence Hub platform is located in a water depth of 8,000 feet and serves as a regional hub for up to 1 billion cubic feet of natural gas production per day from multiple ultra-deepwater fields in the eastern Gulf of Mexico. Finally, through a consolidated 50% owned entity, we are actively converting a vessel into a floating production unit, which we intend to initially use to handle the future oil and gas production from our Phoenix field in the Gulf of Mexico (see Item 2. Properties – Significant Oil and Gas Properties).

OIL AND GAS

We formed our oil and gas operations in 1992 to develop and provide more efficient solutions for the abandonment requirements of companies operating offshore, to expand the asset utilization of our contracting services assets and to achieve incremental returns for our contracting services. 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. In July 2006, we acquired Remington Oil and Gas Corporation ("Remington"), an exploration, development and production company with operations located primarily in the Gulf of Mexico. This acquisition has led to the assembly of services that allows us to create value at key points in the life of a reservoir from exploration through development and operating through the field's final abandonment. As of December 31, 2008, we had 665 Bcfe of estimated proved reserves with approximately 98% associated with properties located in the Gulf of Mexico. As discussed in "The Industry and Our Strategy" below, in December 2008, we announced that we intend to seek the potential sale of part or all of our oil and gas operations, however; until any potential disposition occurs, we believe that owning interests in reservoirs, particularly in deepwater, provides the following:

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

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 returns on our oil and gas investments by lowering F&D costs, reducing development time, operating our fields more effectively, and extending the reservoir life through well exploitation operations. Our reservoir engineering and geophysical expertise, along with our access to contracting services assets that may positively impact a project's development costs, have enabled us to partner with many other oil and gas companies in offshore development projects.

Our contracting services includes three of our business segments, Contracting Services, Shelf Contracting and Production Facilities. Our fourth business segment is Oil and Gas. Significant financial information relating to our operations by segments and by geographic areas for the last three years is contained in Item 8. Financial Statements and Supplementary Data "— Note 19 — Business Segment Information."

THE INDUSTRY AND OUR STRATEGY

In December 2008, we announced our intention to focus and shape the future direction of the Company around our deepwater construction and well intervention services. We intend to achieve this strategic focus by seeking and evaluating strategic opportunities to:

1) Divest all or a portion of our oil and gas assets;
2) Divest our ownership interests in one or all production facilities; and
3) Dispose of our remaining 51% interest in our majority owned subsidiary, CDI.

We have engaged financial advisors to assist us in these efforts. The current economic and financial market conditions may affect the timing of any strategic dispositions by us and will require a degree of patience in order to execute any transactions. As a result, we are unable to be specific with respect to a timetable for any disposition, but we intend to aggressively focus on reducing our indebtedness through monetization of non-core assets and allocation of free cash flow in order to accelerate our strategic goals. We cannot assure you that any or all of the proposed strategic dispositions will be completed or that we will be able to negotiate a favorable price and/or terms. Dispositions of any material assets and/or investments in our non-core businesses will require obtaining approval from our Board of Directors before consummation.

Consistent with this strategy, in December 2008 we announced the sale of our 17.5% non-operating working interest in the Bass Lite oil and gas field for $49 million in gross proceeds and in January 2009 we entered into a stock repurchase agreement with CDI that resulted in us selling approximately 13.6 million shares of CDI common stock held by us to CDI for $86 million in gross proceeds. The sale reduced our ownership of CDI from approximately 57% to our current approximate 51% ownership position.

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

The global economic conditions deteriorated significantly over the past year with declines in the oil and gas market accelerating during the fourth quarter of 2008. Although we currently are experiencing a current market downturn, 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; (2) peaking global production rates; (3) globalization of the natural gas market; (4) increasing number of mature and small reservoirs; (5) increasing ratio of contribution to global production from marginal fields; (6) increasing offshore activity, particularly in Deepwater; and (7) increasing number of subsea developments. Our current strategy of combining contracting services operations and oil and gas operations allows us to focus on trends (4) through (7) 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 have an equity stake.

Our primary goal is to provide services and methodologies to the 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 find and develop oil and gas employing our key services and methodologies resulting in a reduction in F&D 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 capital investments have included adding offshore drilling capability to our Q4000 vessel, converting a vessel into a dynamically positioned floating production unit (Helix Producer I), converting a former dynamically positioned cable lay vessel into a deepwater pipelay vessel (the Caesar), and constructing the Well Enhancer vessel with greater well servicing capabilities in the North Sea.

Monetize Oil and Gas Reserves and Non-Core Assets. We intend to sell down interests in oil and gas reserves once value has been created via prospect generation, discovery and/or development engineering. Through this approach we seek to lower reservoir and commodity risk, lower capital expenditures and increase third party contracting services profits. We may sell interests in oil and gas reserves at any time during the life of the properties.

As stated previously, we will focus on services which are critical to lowering F&D costs, particularly on marginal fields in the deepwater. As the strategy of our Shelf Contracting segment does not focus on minimizing F&D cost, in December 2006, a minority stake (26.5%) in this business was sold through a carve-out initial public offering. Our interest in CDI was further reduced through CDI's acquisition of Horizon Offshore, Inc. ("Horizon") in December 2007 and was 57.2% at December 31, 2008. In January 2009, CDI acquired 13.6 million shares of its outstanding common shares from us reducing our current ownership in CDI to approximately 51%. See Item 8. Financial Statements and Supplementary Data "— Note 5 — Acquisition of Horizon Offshore, Inc." We believe the Shelf Contracting segment, CDI, is better positioned for growth as a stand-alone entity.

Generate Prospects and Focus Exploration Drilling on Select Deepwater Prospects. Our oil and gas operations continue to function normally following our December 2008 announcement that all or a portion of such properties may be sold. This means we will continue to generate prospects and drill in areas where we believe our contracting services assets can be utilized and incremental returns will be achieved through control of and application of our development services and methodologies. To minimize our F&D costs, we expect to utilize the Q4000 for many of our deepwater drilling needs once regulatory approval has been obtained. Additionally, 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 a significant return on capital 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, 2008, the PUD category for our U.S Gulf of Mexico properties, totaled approximately 319 Bcfe or 49% of our total domestic estimated proved reserves. All of our U.K proved reserves are considered to be PUD at December 31, 2008. 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 service business and/or retire outstanding debt.

Certain Definitions

Defined below are certain terms helpful to understanding our business:

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

Deepwater: Water depths exceeding 1,000 feet.

Dive Support Vessel (DSV): Specially equipped vessel that performs services and acts as an operational base for divers, remotely operated vehicles ("ROV") and specialized equipment.

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

DP-2: Two DP systems on a single vessel pursuant to which the redundancy 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 are necessary to provide the redundancy required to support safe deployment of divers, while only a single DP system is necessary to support ROV operations.

EHS: Environment, Health and Safety programs to protect the environment, safeguard employee health and eliminate injuries.

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.

IMR: Inspection, maintenance and repair activities.

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, contract operations, well intervention, recompletion and abandonment.

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

Minerals Management Service (MMS): The federal regulatory body for the United States having responsibility for the mineral resources of the United States OCS.

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

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

Moonpool: An opening in the center of a vessel through which a saturation diving system or ROV may be deployed, allowing safe deployment in adverse weather conditions.

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: Defined in this Annual Report as comprising 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: Defined in this Annual Report as comprising ATP Oil & Gas Corp (NASDAQ: ATPG), W&T Offshore, Inc. (NYSE: WTI), and Mariner Energy, Inc. (NYSE: ME).

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, 2009.

Proved Developed Reserves: 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.

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 3000m. Because the system operates from the seafloor there is no need for surface drilling strings and the larger support spreads required for conventional coring.

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

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

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

Stranded Field: Smaller PUD reservoir that standing alone may not justify the economics of a host production facility and/or infrastructure connections.

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.

Ultra-Deepwater: Water depths beyond 4,000 feet.

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.

CONTRACTING SERVICES OPERATIONS

We provide a full range of contracting services primarily in the Gulf of Mexico, North Sea, Asia Pacific and Middle East regions in both the shallow water and deepwater. Our services include:

- Exploration support. Pre-installation surveys; rig positioning and installation assistance; drilling inspection; subsea equipment maintenance; reservoir engineering; G&G services; modeling; well design; and engineering;

- Development. Installation of small platforms on the OCS, installation of subsea pipelines, flowlines, control umbilicals, manifolds, 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, maintenance and repair of production structures, risers, pipelines and subsea equipment; well intervention; life of field support; reservoir management; provision of production technology; and intervention engineering; and

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

We provide offshore services and methodologies that we believe are critical to finding and developing offshore reservoirs and maximizing production economics, particularly from marginal fields. These "life of field" services are represented by five disciplines: (1) construction, (2) well operations, (3) reservoir and well technology services, (4) drilling and (5) production facilities. As of December 31, 2008, our contracting services operations' backlog supported by written agreements or contracts totaled $897.8 million, of which $668.4 million was expected to be completed in 2009. 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.

Construction

Subsea

Construction services which we believe are critical to the development of fields in the deepwater include the use of pipelay vessels and remotely operated vessels (“ROVs”). We currently own three subsea umbilical 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 Caeser is 485 feet long and has a state-of-the-art DP-2 system. We are currently converting the Caeser into a subsea pipelay asset capable of laying rigid pipe up to 42 inches in diameter. Our total investment in the Caesar is expected to range between $210 million and $230 million when it is completed, which is expected in the second half of 2009. We also periodically provide construction services from our well intervention vessels, Seawell and Q4000. A new well intervention vessel, the Well Enhancer, is expected to be placed in service in the second quarter of 2009.

We operate ROVs, trenchers and ROV Drills designed for offshore construction, rather than supporting drilling rig operations. 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 38 ROVs and six trencher systems operate in three regions: the Americas, Europe/West Africa and Asia Pacific.

The results of our Subsea division are reported under our Contracting Services segment. See Item 8. Financial Statements and Supplementary Data "— Note 19 — Business Segment Information."

Shelf Contracting

Our Shelf Contracting segment represents the operations and results of CDI, our consolidated, majority-owned subsidiary. CDI provides manned diving services, pipelay and pipebury services with CDI's six pipelay/pipebury barges. These barges are able to install, bury and repair pipelines having outside diameters of up to 36 inches, and employ conventional S-lay technology that is appropriate for operating on the Gulf of Mexico OCS and the international areas where we currently operate. CDI also performs platform installation and salvage services utilizing CDI's two derrick barges which are equipped with cranes designed to lift and place platforms, structures or equipment into position for installation. Based on the size of its fleet, we believe that CDI is the market leader in the diving support business, which involves services such as construction, inspection, maintenance, repair and decommissioning of offshore production and pipeline infrastructure on the Gulf of Mexico OCS. CDI also provides these services directly or through partnering relationships in select international offshore markets, such as the Middle East and Asia Pacific. Within this segment we currently own and operate a diversified fleet of 31 vessels, including 21 surface and saturation diving support vessels, six pipelay/pipebury barges, one dedicated pipebury barge, one combination derrick/pipelay barge and two derrick barges. Pipelay and pipe burial operations typically require extensive use of our diving services; therefore, we consider these services to be complementary.

Shelf Contracting performs saturation, surface and mixed gas diving which enable us to provide a full complement of manned diving services in water depths of up to 1,000 feet. CDI provides saturation diving services in water depths of 200 to 1,000 feet through its fleet of eight saturation diving vessels and ten portable saturation diving systems. We also believe that CDI's fleet of diving support vessels is among the most technically advanced in the industry because a number of these vessels have features such as dynamic positioning, hyperbaric rescue chambers, multi-chamber systems for split-level operations and moon pool deployment, which allow us to operate effectively in challenging offshore environments. CDI provides surface and mixed gas diving services in water depths typically less than 300 feet through our 13 surface diving vessels. We believe that CDI's fleet of diving support vessels is the largest in the world.

On December 11, 2007, CDI completed its acquisition of Horizon, through the merger of Horizon with and into a wholly owned subsidiary of CDI, which resulted in Horizon becoming a wholly owned subsidiary of CDI. Under the terms of the merger, each share of Horizon's common stock was converted into the right to receive $9.25 in cash and 0.625 shares of CDI's common stock. All shares of Horizon restricted stock that had been issued but had not vested prior to the effective time of the merger became fully vested at the effective time of the merger and converted into the right to receive the merger consideration. CDI issued an aggregate of approximately 20.3 million shares of common stock and paid approximately $300 million in cash in the merger. The cash portion of the merger consideration was paid from CDI's cash on hand and from borrowings under its $675 million credit facility consisting of a $375 million senior secured term loan and a $300 million senior secured revolving credit facility. See Item 8. Financial Statements and Supplementary Data "— Note 11 — Long-Term Debt."

In January 2009, CDI purchased from us approximately 13.6 million shares of its common stock for $86 million or $6.34 per share. We still hold approximately 47.9 million shares of CDI common stock representing approximately 51% of its total outstanding shares of common stock.

CDI has substantially increased the size of its Shelf Contracting fleet and expanded its operating capabilities on the Gulf of Mexico OCS through strategic acquisitions of Horizon (2007), Acergy US, Inc. ("Acergy") (2006), and the assets of Torch (2005). CDI also acquired Fraser Diving International Limited ("Fraser") (2006).

Shelf Contracting retained our former name of "Cal Dive," and completed a carve-out initial public offering in December 2006. It trades on the New York Stock Exchange under the ticker symbol of "DVR." We received pre-tax net proceeds of $464.4 million from the initial public offering ("IPO"), which included the sale of a 26.5% interest and transfer of debt to CDI.

The results of shelf contracting services are reported under our Shelf Contracting Services segment. See Item 8. Financial Statements and Supplementary Data "— Note 19 — Business Segment Information."

Well Operations

We engineer, manage and conduct well construction, intervention, and decommissioning operations in water depths ranging from 200 to 10,000 feet. The increased number of subsea wells installed and the shortfall in both rig availability and equipment have resulted in an increased demand for Well Operations services in both the Gulf of Mexico and the North Sea.

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 zones or perform recompletions. Two of our vessels serve as work platforms for well operations services at costs significantly less than drilling rigs. In the Gulf of Mexico, our multi-service semi-submersible vessel, the Q4000, has set a series of well operations "firsts" in increasingly deeper water without the use of a traditional drilling rig. In the North Sea, the Seawell has provided intervention and abandonment services for over 500 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 significant backlog for both working assets and, as a result, are constructing a newbuild North Sea vessel, the Well Enhancer. The total cost of the Well Enhancer is expected to be between $200 million and $220 million when it is completed, which is anticipated in the second quarter of 2009. Our operations expanded within Australia and Asia following the acquisition of a well-established Australian well operations company in 2006.

The results of Well Operations are reported under our Contracting Services segment. See Item 8. Financial Statements and Supplementary Data "— Note 19 — Business Segment Information."

Reservoir and Well Technology Services

In 2005, we acquired Helix Energy Limited, which wholly owns Helix RDS, an outsource provider of sub-surface technology skills in the North Sea. With a staff base of over 120 employees, we have the resources to provide valuable well enhancement services, which typically increase production or extend the life of a reservoir, to our own oil and natural gas projects as well as provide these services to our clients. Each team we assign to a specific client comprises a diverse set of skills, including reservoir engineering, geology, modeling, flow assurance, completions, well design and production enhancement. Helix RDS has an established market presence in regions identified as strategically important to our future growth, including offices in Aberdeen and London in the United Kingdom, Kuala Lumpur, Malaysia and Perth, Australia.

The results of reservoir and well technology services are reported under our Contracting Services segment. See Item 8. Financial Statements and Supplementary Data "— Note 19 — Business Segment Information."

Drilling

Contract drilling is a service we have not historically provided but have been contemplating since the construction of our Q4000 vessel over eight years ago. We added drilling capability to the Q4000 in 2008. The fundamentals for deepwater rigs have been favorable in recent years, reflecting significant demand and a limited availability of such rigs. Although the deterioration in the worldwide capital markets led a number of oil and gas companies to recently curtail or announce anticipated reductions to their near-term capital expenditure budgets, we believe that the long-term deepwater projects will mostly be unaffected because of the significant oil and gas reserves associated with such projects and the relatively long lead times required to develop these fields for production, The drilling cost of a subsea development can be as much as 50% of the total F&D costs for a deepwater prospect. The Q4000's drilling capability primarily focuses on the use hybrid slim-bore technology capable of drilling and completing 6-inch slimbore wells to 22,000 feet total depth and operating in up to 6,000 feet of water, which will allow us to drill many of our own deepwater prospects and support the exploration and appraisal efforts of our clients. We expect approval from the MMS for cased well services including completions in 2009 and approval for drilling once we have satisfied MMS requirements.

The results of drilling services are reported under our Contracting Services segment. See Item 8. Financial Statements and Supplementary Data "— Note 19 — Business Segment Information."

Production Facilities

We own interests in certain production facilities in hub locations where there is potential for significant 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 services. Ownership of production facilities enables us to earn a transmission company type return through tariff charges while providing construction work for our vessels. We own a 50% interest in Deepwater Gateway which owns the Marco Polo TLP, which was installed in 4,300 feet of water in the Gulf of Mexico in order to process production from the Marco Polo field discovery. 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 1 billion cubic feet of natural gas production per day from multiple ultra-deepwater fields in the previously untapped eastern Gulf of Mexico.

When a hub is not feasible, we intend to apply an integrated application of our services in a manner that cumulatively lowers development costs to a point that allows for a small dedicated facility to be used. This strategy will permit the development of some fields that otherwise would be non-commercial to develop. The commercial risk is mitigated because we have a portfolio of reservoirs and the assets to redeploy the facility. For example, through a consolidated 50% owned entity, we are currently converting a vessel into a dynamically positioned floating production unit. We intend this unit to first be utilized on the 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 area 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.

The results of production facilities services are reported under our Production Services segment. See Item 8. Financial Statements and Supplementary Data "— Note 19 — Business Segment Information."

OIL & GAS OPERATIONS

We formed our oil and gas operations 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 for our contracting services. 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. In July 2006, we acquired Remington, an exploration, development and production company with operations primarily in the Gulf of Mexico, for approximately $1.4 billion in cash and Helix common stock and the assumption of $358.4 million of liabilities. This acquisition led to the assembly of services that allows us to create value at key points in the life of a reservoir from exploration through development, life of field management and operating through abandonment. As of December 31, 2008, our estimated proved reserves totaled 665 Bcfe with approximately 98% of such reserves associated with properties located in the Gulf of Mexico.

As announced in December 2008, we seek 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 assure you that the sale of all or any portion of the oil and gas operations will be completed or that we will be able to negotiate an acceptable price or acceptable terms. Also, any material disposition of assets and/or investments in our non-core businesses will require obtaining approval from our Board of Director's before any definitive agreement can be reached. We believe that owning interests in reservoirs, particularly in deepwater, provides the following:

- a potential backlog for our service assets as a hedge against cyclical service asset utilization;

- potential utilization for new non-conventional applications of 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 deepwater undeveloped reservoirs. 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 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 will generate significant life of field services for our vessels. To minimize F&D costs, we expect to utilize the Q4000 for many of our deepwater future drilling needs. Our Oil and Gas segment has a proven track record of cost effectively turning prospects into production on the OCS, and we believe similar success is achievable in the deepwater. We plan to seek partners on these prospects to mitigate risk associated with the cost of drilling and development work.

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 offshore 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 F&D costs, lowering development time and cost, operating the field more effectively, and extending the reservoir life through well exploitation operations. When a company sells an OCS property, it retains the financial responsibility for plugging and decommissioning 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, 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 Natural Gas and Oil Reserve Data" for detailed disclosures of our oil and gas properties.

The results of our oil and gas operations are reported under our Oil and Gas segment. See Item 8. Financial Statements and Supplementary Data "— Note 19 — Business Segment Information."

GEOGRAPHIC AREAS

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

	Year Ended December 31,		
	2008	2007	2006
United States	$ 1,394,246	$ 1,261,844	$ 1,063,821
United Kingdom	181,108	230,189	190,064
India	214,288	36,433	—
Other	358,707	238,979	113,039
Total	$ 2,148,349	$ 1,767,445	$ 1,366,924

We include the property and equipment, net 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,		
	2008	2007	2006
United States	$ 3,170,866	$ 3,014,283	$ 2,068,342
United Kingdom	207,156	189,117	110,451
Other	41,568	41,288	33,665
Total	$ 3,419,590	$ 3,244,688	$ 2,212,458

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 construction services required by any particular contracting customer depends on the size of that customer's capital expenditure budget devoted to construction plans 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 of major customers, those whose total represented 10% or more of our consolidated revenues, was as follows: 2008 — Louis Dreyfus Energy Services (10%) and Shell Offshore, Inc. (11%); 2007 — Louis Dreyfus Energy Services (13%) and Shell Offshore, Inc. (10%); and 2006 — Louis Dreyfus Energy Services (10%) and Shell Trading (US) Company (10%). All of these customers were purchasers of our oil and gas production. We estimate that in 2008 we provided subsea services to over 200 customers.

Our contracting services projects have historically been of short duration and are generally awarded shortly before mobilization. As a result, no significant backlog existed prior to 2007. Beginning in 2007, we have entered into several long-term contracts, for certain of our Deepwater and Well Operations 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.

COMPETITION

The marine contracting 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 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 Acergy S.A., Allseas Group S.A., Subsea 7 Inc. and Technip-Coflexip.

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. Our ability to acquire additional properties depends upon our ability to evaluate and select suitable properties and consummate transactions in a 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 gas demands, 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 on development properties.

TRAINING, SAFETY AND QUALITY ASSURANCE

We have established a corporate culture in which EHS remains among the highest of priorities. Our corporate goal, based on the belief that all accidents can be prevented, is to provide an injury-free workplace by focusing on correct and safe behavior. Our EHS 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 EHS programs are among the best in the industry. We have introduced 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. To further this effort, progressive auditing is done to continuously improve our EHS 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 ("USCG"), the U.S. Environmental Protection Agency, the MMS 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.

We support and voluntarily comply with standards of the Association of Diving Contractors International. 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 MMS.

The MMS 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 MMS.

We acquire production rights to offshore mature oil and gas properties under federal oil and gas leases, which the MMS administers. These leases contain relatively standardized terms and require compliance with detailed MMS regulations and orders pursuant to the Outer Continental Shelf Lands Act ("OCSLA"). These MMS directives are subject to change. The MMS has promulgated regulations requiring offshore production facilities located on the OCS to meet stringent engineering and construction specifications. The MMS also has issued regulations restricting the flaring or venting of natural gas and prohibiting the burning of liquid hydrocarbons without prior authorization. Similarly, the MMS 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 MMS 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.

Under the OCSLA and the Federal Oil and Gas Royalty Management Act, MMS 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 MMS.

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. 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. 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. This act amended the NGPA to remove both price and non-price controls from natural gas sold in “first sales” no later than January 1, 1993.

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, 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. Changes in FERC rules and regulations may also affect the intrastate transportation of natural gas 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. 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. Notwithstanding the foregoing, we do not anticipate that compliance with existing federal, state and local laws, rules and regulations will have a material effect upon our capital expenditures, financial conditions, earnings or competitive position.

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 $0.8 million or $0.95 million 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 MMS has promulgated regulations implementing these financial responsibility requirements for covered offshore facilities. Under the MMS 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 MMS 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 25 vessels over 300 gross tons. We have provided satisfactory evidence of financial responsibility to the Coast Guard for all of our vessels.

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

OCSLA provides the federal government with broad discretion in regulating the production of offshore resources of oil and gas, including authority to impose safety and environmental protection requirements applicable to lessees and permittees operating in the OCS. Specific design and operational standards may apply to OCS vessels, rigs, platforms, vehicles and structures. Violations of lease conditions or regulations issued pursuant to OCSLA can result in substantial civil and criminal penalties, as well as potential court injunctions curtailing operations and cancellation of leases. Because our operations rely on offshore oil and gas exploration and production, if the government were to exercise its authority under OCSLA to restrict the availability of offshore oil and gas leases, such action could have a material adverse effect on our financial condition and results of operations. As of this date, we believe we are not the subject of any civil or criminal enforcement actions under OCSLA.

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

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

Management believes that we are in compliance in all material respects with all 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.

EMPLOYEES

We rely on the high quality of our workforce. As of January 31, 2009, we had approximately 3,600 employees, nearly 800 of which were salaried personnel. Of the total employees, approximately 2,000 were employees of Cal Dive. As of December 31, 2008, we also contracted with third parties to utilize 636 non-U.S. citizens to crew our foreign flag vessels. None of our employees belong to a union nor are 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, 2008, and copies of our Quarterly Reports on Form 10-Q for 2008 and 2009 and any Current Reports on Form 8-K for 2008 and 2009, and any amendments thereto, are or will be available free of charge at such website as soon as reasonably practicable after they are filed with, or furnished to, the Securities and Exchange Commission ("SEC"). In addition, the Investor Relations portion of our website contains copies of our Code of Conduct and Business Ethics and our Code of Ethics for Chief Executive Officer and Senior Financial Officers. We make our website content available for informational purposes only. Information contained on our website is not part of this report and should not be relied upon for investment purposes. Please note that prior to March 6, 2006, the name of the Company was Cal Dive International, Inc.

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

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

Economic conditions 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. During recent months, there has been a substantial downturn in business activity and in the worldwide credit and capital markets that has led to a worldwide economic recession. The consequences of a prolonged recession will include a lower level of economic 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.

Continued market deterioration could also jeopardize the performance of certain counterparty obligations, including those of our insurers, customers and financial institutions. Although we monitor the creditworthiness of our counterparties, the current market conditions could lead to sudden changes in a counterparty's liquidity. 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.

Because of significant declines in both our stock price and commodity prices, in the fourth quarter of 2008 we were required to reduce the amount of our recorded goodwill and other indefinite lived intangibles by approximately $715 million by taking an asset impairment charge to operating expense, most of which affected our oil and gas segment ($704 million). Further stock price or commodity price decreases may result in additional impairment expense charges for our long-lived assets and/or our goodwill associated with our contracting services operations and this could negatively impact our financial condition. Impairment charges do not affect our current or future cash flow.

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

Due to the substantial uncertainty in the global economy, there has been deterioration in the credit and capital markets and access to financing is limited and uncertain. If the capital and credit markets continue to experience weakness and the availability of funds remains limited, we may incur increased costs associated with any additional financing we may require for future operations. Because of uncertainty in the market and an inability to access the capital markets our customers may curtail 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.

In addition, continued lower levels of economic activity and weakness in the credit markets could adversely affect our ability to implement our strategic objectives and dispose of all or any portion of the oil and gas assets, the production facilities or our interest in CDI. We cannot assure you that the proposed strategic dispositions will be completed or that we will be able to negotiate prices or terms that are acceptable to us.

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, 2008, we had approximately $2.1 billion of consolidated indebtedness outstanding ($315 million of which relates to CDI which is non recourse to us). The significant level of combined indebtedness may have an adverse effect on our future operations, including:

- limiting our ability to obtain additional financing on satisfactory terms to fund our working capital requirements, capital expenditures, acquisitions, investments, debt service requirements and other general corporate requirements;

- increasing our vulnerability to the continued general economic downturn, competition and industry conditions, which could place us at a competitive disadvantage compared to our competitors that are less leveraged;

- increasing our exposure to 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 limit 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 defined by our credit agreements).

A continuing period of weak economic activity will 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 is affected by the current 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. We cannot assure you that we would have access to the credit markets as needed to replace our existing debt and we could incur increased costs associated with any available replacement financing.

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;
- 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.

Our ability to market oil and natural gas discovered or produced in any future foreign operations, and the price we could obtain for such production, depends on many factors beyond our control, including:

- ready markets for oil and natural gas;
- the proximity and capacity of pipelines and other transportation facilities;
- fluctuating demand for crude oil and natural gas;
- the availability and cost of competing fuels; and
- the effects of foreign governmental regulation of oil and gas production and sales.

Pipeline and processing facilities do not exist in certain areas of exploration and, therefore, any actual sales of our production could be delayed for extended periods of time until such facilities are constructed.

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 or the North Sea, 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 demands, political change and government regulations.

We may need to change the manner in which we conduct our business in response to changes in government regulations.

Our subsea construction, intervention, inspection, maintenance and decommissioning operations and our oil and gas production from offshore properties, including decommissioning of such properties, are subject to and affected by various types of government regulation, including numerous federal, state and local environmental protection laws and regulations. These laws and regulations are becoming increasingly complex, stringent and expensive to comply with, and significant fines and penalties may be imposed for noncompliance. We cannot assure you that continued compliance with existing or future laws or regulations will not adversely affect our operations or financial condition or cash flow

Government regulation may affect our ability to conduct operations, and the nature of our business exposes us to environmental liability.

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.

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 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.

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.

In addition, changes in environmental laws and regulations, or claims for damages to persons, property, natural resources or the environment, could result in substantial costs and liabilities, and thus there can be no assurance that we will not incur significant environmental compliance costs in the future. Such environmental liability could substantially reduce our net income and could have a significant impact on our financial ability to carry out our operations.

The 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, 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 skilled labor force, increases in the wage rates that we must pay or both. If either of these events were to occur, our capacity and profitability could be diminished and our growth potential could be impaired.

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 55,000 shares of preferred stock issued to Fletcher International, Ltd. under 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 4,945,000 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 contracts 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.

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

We cannot assure you that activity levels for offshore construction will remain the same or increase. A sustained period of low drilling and production activity or the return of 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. We maintain insurance protection as we deem prudent, including Jones Act employee coverage, which is the maritime equivalent of workers' compensation, and hull insurance on our vessels. We cannot assure you that any such insurance will 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 partial divestiture of Cal Dive, a greater percentage of our revenues may 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.

Delays or cost overruns in our construction projects could adversely affect our business, or the expected cash flows from these projects upon completion may not be timely or as high as expected.

We currently have the following significant construction projects in our contracting services operations:

- the construction of the Well Enhancer, a North Sea well services vessel;
- the conversion of the Caesar into a deepwater pipelay asset; and
- the construction of the Helix Producer I, a minimal floating production unit to be initially utilized on the Phoenix field, through a consolidated 50% owned variable interest entity.

Although the construction contracts provide for delay penalties, these projects have been and continue to be subject to the risk of delay or cost overruns inherent in construction projects. These risks include, but are not limited to:

- unforeseen quality or engineering problems;

- work stoppages or labor shortage;
- weather interference;
- unanticipated cost increases;
- delays in receipt of necessary equipment; and
- inability to obtain the requisite permits or approvals.

Significant delays could also have a material adverse effect on expected contract commitments for these assets and our future revenues and cash flow. We will not receive any material increase in revenue or cash flows from these assets until they are placed in service and customers enter into binding arrangements for the assets, which can potentially be several months after the construction or conversion projects are completed. Furthermore, we cannot assure you that customer demand for these assets will be as high as currently anticipated, and as a result, our future cash flows may be adversely affected. In addition, new assets from third-parties may also enter the market in the future and compete with us.

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 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.

We have hedged approximately 73% of our anticipated production for 2009 with a combination of forward sale and financial hedge contracts. The prices for these contracts are significantly higher than the prices for both crude oil and natural gas as of December 31, 2008 and as of the time of this filing on March 2, 2009. If the prices for crude oil and natural gas do not increase 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 2010 and beyond, perhaps significantly, absent offsetting increases in production amounts.

We are vulnerable to risks associated with the Gulf of Mexico because we currently explore and produce almost exclusively in that area.

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 operations may have an adverse effect on our 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 results of operations and financial condition.

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. In addition, we have entered into costless collar contracts and swap contracts related to some of our future oil and gas production. We may from time to time engage in other hedging activities that limit our upside potential from price increases. These sales activities may limit our benefit from dramatic price increases.

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 gas reserves and the estimated future net cash flows therefrom based upon reports for the years ended December 31, 2008 and 2007, audited by our 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, abandonment 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 and abandonment expenses 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 prices 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 87% 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, 2008, approximately 11% of our total estimated proved reserves were PDNP, 27% were PDSI and approximately 49% 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.

Additionally approximately 98% 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 half of our total estimated proved reserves and related estimated discounted future net revenues as of December 31, 2008. 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.

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 87% of our proved reserves at December 31, 2008 are PUDs, PDSI and PDNP. Further, our proved producing reserves at December 31, 2008 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, pipeline shut-ins, or otherwise, this can directly influence our ability to sell commodities that we are able to produce. In addition, with respect to oil and gas projects that we do not operate, we have limited influence over operations, including limited control over the maintenance of safety and environmental standards. The operators of those properties may, depending on the terms of the applicable joint operating agreement:

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

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

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

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

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

We own a fleet of 39 vessels and 37 ROVs, 5 trenchers, and 2 ROVDrills. We also lease six vessels, one trencher and one ROV. We believe that the market in the Gulf of Mexico requires specially designed and/or equipped vessels to competitively deliver subsea construction and well operations services. Eleven of our vessels have DP capabilities specifically designed to respond to the deepwater market requirements. Fifteen of our vessels (13 of which are based in the Gulf of Mexico) have the capability to provide saturation diving services.

Divestitures in 2008

In March and April 2008, we sold a total 30% working interest in the Bushwood discoveries (Garden Banks Blocks 463, 506 and 507) and other Outer Continental Shelf oil and gas properties (East Cameron Blocks 371 and 381), in two separate transactions 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 based upon certain field production milestones. The new co-owners will also pay their pro rata share of all future capital expenditures related to the exploration and development of these fields. Decommissioning liabilities will be shared on a pro rata share basis between the new 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 investor. 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. The sale had three separate closings and an effective date of November 1, 2008. Proceeds from the sale were used to fund our working capital requirements.

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 or Anchor Moored	Crane Capacity (tons)
CONTRACTING SERVICES:							
Pipelay —							
Caesar (3)(4)	Vanuatu	1/2006	482	220	—	DP	300 and 36
Express (4)	Vanuatu	8/2005	520	132	—	DP	500 and 120
Intrepid (4)	Bahamas	8/1997	381	50	—	DP	400
Talisman (4)	U.S.	11/2000	195	14	—	—	—
REM Forza (10)	Norway	9/2008	355	120	Capable	DP	250
Floating Production Unit —							
Helix Producer I (5)	Bahamas	—	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
Well Enchancer (7)	U.K.	—	432	120	Capable	DP	100
Robotics —							
38 ROVs, 6 Trenchers and 2 ROVDrills (8)(9)	—	Various	—	—	—	—	—
Northern Canyon (10)	Bahamas	6/2002	276	58	—	DP	50
Olympic Canyon (10)	Norway	4/2006	304	87	—	DP	150
Olympic Triton (10)	Norway	11/2007	311	87	—	DP	150
Seacor Canyon (10)	Majuro Marshall Island	4/2007	221	40	—	DP	20
Island Pioneer (10)	Vanuatu	5/2008	312	110	—	DP	140
SHELF CONTRACTING (CAL DIVE INTERNATIONAL, INC.):							
Pipelay/Pipebury —							
Brave (11)	U.S.	11/2005	275	80	—	Anchor	30 and 50
Rider (11)	U.S.	11/2005	260	80	—	Anchor	50
American (11)	U.S.	12/2007	180	74	—	Anchor	90
Lone Star (11)	Vanuatu	12/2007	313	177	—	Anchor	88
Brazos (11)	Vanuatu	12/2007	210	119	—	Anchor	90
Pecos (11)	U.S.	12/2007	256	102	—	Anchor	114
Pipebury —							
Canyon (11)	Vanuatu	12/2007	330	110	—	Anchor	88
Derrick/Pipelay —							
Sea Horizon	Vanuatu	12/2007	360	255	—	Anchor	1,200
Derrick —							
Atlantic (11)	U.S.	12/2007	420	158	—	Anchor	500

Pacific (11)	U.S.	12/2007	350	109	—	Anchor	1,000
Saturation Diving —							
DP DSV Eclipse (11)	Bahamas	3/2002	367	109	Capable	DP	5; 4.3; 92/43; 20.4 A-Frame
DP DSV Kestrel (11)	Vanuatu	9/2006	323	80	Capable	DP	40; 15; 10; Hydralift HLR 308
DP DSV Mystic Viking (11)	Bahamas	6/2001	253	60	Capable	DP	50
DP MSV Texas Horizon (11)	Vanuatu	12/2007	341	96	Capable	DP	113
DP MSV Uncle John (11)	Bahamas	11/1996	254	102	Capable	DP	2×100
DSV American Constitution (11)	Panama	11/2005	200	46	Capable	4 point	20.41
DSV Cal Diver I (11)	U.S.	7/1984	196	40	Capable	4 point	20
DSV Cal Diver II (11)	U.S.	6/1985	166	32	Capable	4 point	40 A-Frame
Surface Diving —							
Cal Diver IV (11)	U.S.	3/2001	120	24	—	—	—
DSV American Star (11)	U.S	11/2005	165	30	—	4 point	9.072
DSV American Triumph (11)	U.S.	11/2005	164	32	—	4 point	13.61
DSV American Victory (11)	U.S.	11/2005	165	34	—	4 point	9.072
DSV Dancer (11)	U.S.	3/2006	173	34	—	4 point	30
DSV Mr. Fred (11)	U.S.	3/2000	166	36	—	4 point	25
DSV Midnight Star (11)	Vanuatu	6/2006	197	42	—	4 point	20 and 40
Fox (11)	U.S.	10/2005	130	42	—	—	—
Mr. Jack (11)	U.S.	1/1998	120	22	—	—	10
Mr. Jim (11)	U.S.	2/1998	110	19	—	—	—
Polo Pony (11)	U.S.	3/2001	110	25	—	—	—
Sterling Pony (11)	U.S.	3/2001	110	25	—	—	—
White Pony (11)	U.S.	3/2001	116	25	—	—	—

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(1) Under government regulations and our insurance policies, we are required to maintain our vessels in accordance with standards of seaworthiness and safety set by government regulations and classification organizations. We maintain our fleet to the standards for seaworthiness, safety and health set by the ABS, Bureau Veritas ("BV"), Det Norske Veritas ("DNV"), Lloyds Register of Shipping ("Lloyds"), and the USCG. The 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) Currently under conversion into a deepwater pipelay asset with completion expected in the second half of 2009.

(4) Subject to vessel mortgages securing our Senior Credit Facilities described in Item 8. Financial Statements and Supplementary Data "— Note 11 — Long-term Debt."

(5) Former ferry vessel undergoing conversion into DP floating production unit for initial use on our Phoenix field. See Production Facilities on page 31.

(6) Subject to vessel mortgage securing our MARAD debt described in Item 8. Financial Statements and Supplementary Data "— Note 11 — Long-term Debt."

(7) Currently under construction and expected to be placed into service in second quarter 2009.

(8) Owned and operated by our domestic subsidiary under a secured lien, except for one ROV and one Trencher which are leased.

(9) Average age of our fleet of ROVs, trenchers and ROV Drills is approximately 4.5 years.

(10) Leased.

(11) Subject to vessel mortgages securing CDI's $675 million credit facility described in Item 8. Financial Statements and Supplementary Data "— Note 11 — Long-term Debt."

In addition to CDI's saturation diving vessels, CDI currently owns ten portable saturation diving systems, including six acquired from Fraser.

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, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
Contracting Services:			
Pipelay	92%	79%	87%
Well operations	70%	71%	81%
ROVs	73%	78%	76%
Shelf Contracting	60%	65%	84%

We incur routine drydock, inspection, maintenance and repair costs pursuant to Coast Guard regulations and 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 in other vessels on a short-term basis, such as tugboats, cargo barges, utility boats and dive support vessels.

PRODUCTION FACILITIES

Through our interest in Deepwater Gateway, a limited liability company in which Enterprise Products Partners L.P. is the other member, we own a 50% interest in the Marco Polo TLP, which was installed on Green Canyon Block 608 in 4,300 feet of water. 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. Anadarko required 50,000 barrels of oil per day and 150 million feet per day of processing capacity for Marco Polo. The Marco Polo TLP was designed to process 120,000 barrels of oil per day and 300 million cubic feet of gas per day and payload with space for up to six subsea tie backs.

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.

We own a 20% interest in the Gunnison truss spar facility, together with the operator Kerr-McGee Oil & Gas Corporation ("Kerr-McGee"), which owns a 50% interest, and Nexen, Inc., which owns the remaining 30% interest. The Gunnison spar, which is moored in 3,150 feet of water and located on Garden Banks Block 668, has daily production capacity of 40,000 barrels of oil and 200 million cubic feet of gas. This facility is designed with excess capacity to accommodate production from satellite prospects in the area.

Further, we, along with Kommandor Rømø, a Danish corporation, formed a joint venture company called Kommandor LLC to convert a ferry vessel into a floating production unit to be named the Helix Producer I. The total cost of the ferry and its initial conversion is estimated to range between $150 million and $160 million, We have provided $84.7 million in interim construction financing through December 31, 2008 to the joint venture on terms that would equal an arms length financing transaction, and Kommandor Rømø has provided $5 million on the same terms.

Total equity contributions and indebtedness guarantees provided by Kommandor Rømø are expected to total $42.5 million. The remaining costs to complete the project will be provided by us through equity contributions. Under the terms of the operating agreement for the joint venture, if Kommandor Rømø elects not to make further contributions to the joint venture, the ownership interests in the joint venture will be adjusted based on the relative contributions of each partner to the total of all contributions and project financing guarantees.

Upon completion of the initial conversion, scheduled for second quarter 2009, we will charter the Helix Producer I from Kommandor LLC, and plan to install, at 100% our cost, processing facilities and a disconnectable fluid transfer system on the Helix Producer I for initial use on our Phoenix field. The cost of these additional facilities is estimated to approximate $200 million when the work is expected to be completed in early 2010. As of December 31, 2008, approximately $210.1 million of costs related to the purchase of the Helix Producer I ($20 million), conversion of the Helix Producer I and construction of the additional facilities had been incurred, with an additional $4.9 million committed. Kommandor LLC qualified as a variable interest entity under FIN 46(R). We determined that we were the primary beneficiary of Kommandor LLC and thus have consolidated the financial results of Kommandor LLC as of December 31, 2008 in our Production Facilities segment. Kommandor LLC has been a development stage enterprise since its formation in October 2006.

SUMMARY OF NATURAL GAS AND OIL RESERVE DATA

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 and independent petroleum engineers analyzed 100% of our United States oil and gas fields on an annual basis (107 fields as of December 31, 2008). We consider any field with discounted future net revenues of 1% or greater of the total discounted future net revenues of all our fields to be significant. An "engineering audit," as we use the term, is a process involving an independent petroleum engineering firm's (Huddleston & Co., Inc. ("Huddleston")) extensive visits, collection and examination of all geologic, geophysical, engineering and economic data requested by the independent petroleum engineering firm. Our use of the term "engineering audit" is intended only to refer to the collective application of the procedures which Huddleston was engaged to perform and may be defined and used differently by other companies.

The engineering audit of our reserves by the independent petroleum engineers involves their rigorous examination of our technical evaluation, interpretation and extrapolations of well information such as flow rates and reservoir pressure declines as well as other technical information and measurements. Our internal reservoir engineers interpret this data to determine the nature of the reservoir and ultimately the quantity of proved oil and gas reserves attributable to a specific property. Our proved reserves in this Annual Report include only quantities that we expect to recover commercially using current prices, costs, existing regulatory practices and technology. While we are reasonably certain that the proved reserves will be produced, the timing and ultimate recovery can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and changes in projections of long-term oil and gas prices. Revisions can include upward or downward changes in the previously estimated volumes of proved reserves for existing fields due to evaluation of (1) already available geologic, reservoir or production data or (2) new geologic or reservoir data obtained from wells. Revisions can also include changes associated with significant changes in development strategy, oil and gas prices, or the related production equipment/facility capacity. Huddleston also examined our estimates with respect to reserve categorization, using the definitions for proved reserves set forth in Regulation S-X Rule 4-10(a) and subsequent SEC staff interpretations and guidance.

In the conduct of the engineering audit, Huddleston did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties or sales of production. However, if in the course of the examination something came to the attention of Huddleston which brought into question the validity or sufficiency of any such information or data, Huddleston did not rely on such information or data until it had satisfactorily resolved its questions relating thereto or had independently verified such information or data. Furthermore, in instances where decline curve analysis was not adequate in determining proved producing reserves, Huddleston evaluated our volumetric analysis, which included the analysis of production and pressure data. Each of the PUDs analyzed by Huddleston included volumetric analysis, which took into consideration recovery factors relative to the geology of the location and similar reservoirs. Where applicable, Huddleston examined data related to well spacing, including potential drainage from offsetting producing wells in evaluating proved reserves for un-drilled well locations.

The engineering audit by Huddleston included 100% of our producing properties together with essentially all of our non-producing and undeveloped properties. Properties for analysis were selected by us and Huddleston based on discounted future net revenues. All of our significant properties were included in the engineering audit and such audited properties constituted approximately 97% of the total discounted future net revenues. Huddleston also analyzed the methods utilized by us in the preparation of all of the estimated reserves and revenues. Huddleston represents in its audit report that it believes our methodologies are consistent with the methodologies required by the

SEC, Society of Petroleum Engineers ("SPE") and FASB. There were no limitations imposed, nor limitations encountered by us or Huddleston.

The table below sets forth information, as of December 31, 2008, with respect to estimates of net proved reserves. 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, 2008		
	Proved Developed Reserves	Proved Undeveloped Reserves	Total Proved Reserves
United States:			
Gas (Bcf)	257	203	460
Oil (MMBbls)	13	19	32
Total (Bcfe)	333	319	652
United Kingdom:			
Gas (Bcf)	1	12	13
Oil (MMBbls)	—	—	—
Total (Bcfe)	1	12	13
Total:			
Gas (Bcf)	258	215	473
Oil (MMBbls)	13	19	32
Total (Bcfe)	334	331	665

For additional information regarding estimates of oil and gas reserves, including estimates of proved and proved developed reserves, the standardized measure of discounted future net cash flows, and the changes in discounted future net cash flows, see Item 8. Financial Statements and Supplementary Data "— Note 21— Supplemental Oil and Gas Disclosures."

Significant Oil and Gas Properties

Our oil and gas properties consist primarily of interests in developed and undeveloped oil and gas leases. As of December 31, 2008, we had exploration, development and production operations in the United States, primarily in the Gulf of Mexico. In December 2006, we acquired the Camelot field, located in the North Sea, in which we subsequently sold a 50% interest in June 2007. This is our only developed oil and gas property in the United Kingdom.

Our U.S. operations accounted for approximately 99% of our 2008 production and approximately 98% of total proved reserves at December 31, 2008 (87% of such total reserves are PUDs, PDSI and PDNP). Further, our proved producing reserves at December 31, 2008 are expected to experience annual decline rates ranging from 30% to 40% over the next ten years. The following table provides a brief description of our domestic and international oil and gas properties we consider most significant to us at December 31, 2008:

	Development Location	Net Total Proved Reserves (Bcfe)	Net Proved Reserves Mix		2008 Net Production (Bcfe)	Average WI%	Expected First Production
			Oil %	Gas %			
United States Offshore:							
Deepwater							
Bushwood(1)	U.S. GOM	314	10	90	-	51	Jan 2009

Phoenix(2)	U.S. GOM	42	79	21	-	70	2010
Gunnison(3)	U.S. GOM	23	51	49	4	19	Producing

	Development Location	Net Total Proved Reserves (Bcfe)	Net Proved Reserves Mix Oil %	Gas %	2008 Net Production (Bcfe)	Average WI%	Expected First Production
Outer Continental Shelf	U.S. GOM						
East Cameron 346	U.S. GOM	36	80	20	1	75	Producing
High Island A557	U.S. GOM	22	74	26	2	100	Producing
South Timbalier 86/63	U.S. GOM	32	39	61	4	91	Producing
South Pass 89	U.S. GOM	22	73	17	1	27	Producing
Mobile 863	U.S. GOM	20	-	100	-	83	2010
West Cameron 170	U.S. GOM	16	30	70	1	55	Producing
East Cameron 339	U.S. GOM	10	69	31	4	100	Producing
Eugene Island 302	U.S. GOM	10	63	37	1	58	PDSI 2010
South Marsh Island 130	U.S. GOM	13	73	27	2	100	Producing
United Kingdom Offshore(4)	UK Offshore	13	-	100	1	50	PDSI 2009

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

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

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

(4) Consists of our only developed property in the United Kingdom, Camelot.

United States Offshore

Deepwater

The estimated proved reserves associated with our three fields in the Deepwater of the Gulf of Mexico totaled 379 Bcfe or approximately 57 % of our total estimated proved reserves at December 31, 2008. We are the operator of two of the three fields, which comprised approximately 94% of our Deepwater proved reserves (approximately 53% of total proved reserves). Gunnison, a non-operated field, has been producing since December 2003. Our net production in Deepwater totaled approximately 8 Bcfe in 2008. As long as we continue to have interest in properties in Deepwater, we will continue to advance our Deepwater development activities and may pursue additional future exploration opportunities.

Outer Continental Shelf

Our estimated proved reserves for our 102 fields in the Gulf of Mexico on the OCS totaled approximately 273 Bcfe or 41% of our total estimated proved reserves as of December 31, 2008. Our net production from the OCS properties totaled approximately 39 Bcfe in 2008. Our largest field on the OCS is East Cameron Block 346, whose total estimated proved reserve represents approximately 13% of our aggregated OCS estimated proved reserves (or approximately 5% of total estimated proved reserves). No other individual OCS field comprised over 5% of total estimated proved reserves. We are the operator of 77% of our OCS properties whose composite estimated proved reserves totals 210 Bcfe.

United Kingdom Offshore

In December 2006, we acquired the Camelot field, located in the North Sea, in which we subsequently sold a 50% interest in June 2007. This is our only developed oil and gas property in the United Kingdom. The results of our UK operations were immaterial for each of the three years ended December 31, 2008, 2007 and 2006, 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,		
	2008	2007	2006
Production:			
Gas (Bcf)	31	42	28
Oil (MMBbls)	3	4	3
Total (Bcfe)	47	65	48
Average sales prices realized (including hedges):			
Gas (per Mcf)	$ 9.29	$ 7.69	$ 7.86
Oil (per Bbl)	$ 92.22	$ 67.68	$ 60.41
Total (per Mcfe)	$ 11.43	$ 8.93	$ 8.79
Average production cost per Mcfe	$ 2.99	$ 1.83	$ 1.85
Average depletion and amortization per Mcfe	$ 4.21	$ 3.54	$ 2.79

Productive Wells

The number of productive oil and gas wells in which we held interest as of December 31, 2008 is as follows:

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
United States – Offshore	305	231	375	200	680	431

Productive wells are producing wells and wells capable of production. A gross well is a well in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned. 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 multiple completions and non-producing wells as of December 31, 2008:

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Not producing (shut-in)	44	32	105	62	149	94
Multiple completions	221	169	281	155	502	324

Developed and Undeveloped Acreage

The developed and undeveloped acreage (including both leases and concessions) that we held at December 31, 2008 is as follows:

	Undeveloped		Developed	
	Gross	Net	Gross	Net
United States – Offshore	348,528	280,831	568,253	307,880

United Kingdom – Offshore	25,406	12,703	9,778	4,889
Total	373,934	293,534	578,031	312,769

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 so 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
2009	116,815	80,515
2010	96,726	71,283
2011	25,112	19,112
20122010	32,275	24,595
2013	30,760	30,760
2014	17,280	13,824
2015	5,760	5,760
2016	40,320	38,592
Total	365,048	284,441

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, 2008, 2007 and 2006:

	Net Exploratory Wells			Net Development Wells		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2008	0.4	0.6	1.0	2.4	—	2.4
Year ended December 31, 2007	10.8	1.1	11.9	6.4	1.0	7.4
Year ended December 31, 2006	6.5	2.1	8.6	4.6	—	4.6

No wells were drilled in the United Kingdom in 2008, 2007 and 2006.

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.

At December 31, 2008, our oil and gas operations were completing one development well and one exploration well. See Item 8. Financial Statements and Supplementary Data "— Note 7 — Oil and Gas Properties." These wells are located in the Gulf of Mexico.

FACILITIES

Our corporate headquarters are located at 400 N. Sam Houston Parkway, E., Suite 400, Houston, Texas. The corporate headquarters of CDI are located at 2500 CityWest Boulevard, Suite 2200, Houston Texas. We own the Aberdeen (Dyce), Scotland facility and CDI owns approximately 6½ acres of the Port of Iberia, Louisiana facility and its Port Arthur and Sabine, Texas facilities. All other facilities are leased.

Properties and Facilities Summary

Location	Function	Size
Houston, Texas	Helix Energy Solutions Group, Inc. Corporate Headquarters, Project Management, and Sales Office	92,300 square feet
	Energy Resource Technology GOM, Inc. Corporate Headquarters	
	Well Ops Inc. Corporate Headquarters, Project Management, and Sales Office	
	Kommandor LLC (1) 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	
Aberdeen (Westhill), Scotland	Helix RDS Limited Corporate Offices	
	ERT (UK) Limited Corporate Offices	11,333 square feet
London, England	Helix RDS Limited Corporate Offices	3,365 square feet
Kuala Lumpur, Malaysia	Helix RDS Sdn Bhd Corporate Offices	2,227 square feet
Perth, Australia	Well Ops SEA Pty Ltd Corporate Offices	1.0 acre (Building: 12,040 square feet)
	Helix RDS Pty Ltd	8,202 square feet

Perth, Australia	Corporate Offices	
	Helix ESG 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	
Houston, Texas	Cal Dive International, Inc. (2) Corporate Headquarters, Project Management, and Sales Office	89,000 square feet

Location	Function	Size
Port Arthur, Texas	Cal Dive International, Inc. (2) Marine, Spoolbase	23 acres (Buildings: 6,000 square feet)
Sabine, Texas	Cal Dive International, Inc. (2) Marine, Warehouse	26 acres (Buildings: 59,000 square feet)
Port of Iberia, Louisiana	Cal Dive International, Inc. (2) Operations, Offices and Warehouse	23 acres (Buildings: 68,602 square feet)
Fourchon, Louisiana	Cal Dive International, Inc. (2) Marine, Operations, Living Quarters	10 acres (Buildings: 2,300 square feet)
New Orleans, Louisiana	Cal Dive International, Inc. (2) Sales Office	2,724 square feet
Dubai, United Arab Emirates	Cal Dive International, Inc. (2) Sales Office and Warehouse	29,013 square feet
Perth, Australia	Cal Dive International, Inc. (2) Operations, Offices and Project Management	22,970 square feet
Singapore	Cal Dive International, Inc. (2) Marine, Operations, Offices, Project Management and Warehouse	30,484 square feet
Del Carmen, Mexico	Cal Dive International, Inc. (2) Operations, Offices and dock	8,165 sq. ft.
Jakarta, Indonesia	Cal Dive International, Inc. (2) Sales Offices and dock	1,733 sq. ft.
Vietnam	Cal Dive International, Inc. (2) Sales Office	603 sq. ft.
Nigeria	Cal Dive International, Inc. (2) Project Management	13,136 sq. ft.

(1) Kommandor LLC is a joint venture in which we owned 50% at December 31, 2008. Kommandor LLC is included in our consolidated results as of December 31, 2008.

(2) Cal Dive International, Inc. is our Shelf Contracting subsidiary, of which we owned 57.2% at December 31, 2008 and currently own approximately 51%.

Item 3. Legal Proceedings.

Insurance and Litigation

Our operations are subject to the inherent risks of offshore marine activity, including accidents resulting in personal injury and the loss of life or property, environmental mishaps, mechanical failures, fires and collisions. We insure against these risks at levels consistent with industry standards. We also carry workers' compensation, maritime employer's liability, general liability and other insurance customary in our business. All insurance is carried at levels of coverage and deductibles that we consider financially prudent. Our services are provided in hazardous environments where accidents involving catastrophic damage or loss of life could occur, and litigation arising from such an event may result in our being named a defendant in lawsuits asserting large claims. Although there can be no assurance that the amount of insurance we carry is sufficient to protect us fully in all events, or that such insurance will continue to be available at current levels of cost or coverage, we believe that our insurance protection is adequate for our business operations. A successful liability claim for which we are underinsured or uninsured could have a material adverse effect on our business. We also are involved in various legal proceedings, primarily involving claims for personal injury under the General Maritime Laws of the United State and the Jones Act as a result of alleged negligence. In addition, we from time to time incur other claims, such as contract disputes, in the normal course of business.

On December 2, 2005, we received an order from the MMS that the price threshold for both oil and gas was exceeded for 2004 production and that royalties are due on such production notwithstanding the provisions of the Outer Continental Shelf Deep Water Royalty Relief Act of 2005 ("DWRRA"), which was intended to stimulate exploration and production of oil and natural gas in the deepwater Gulf of Mexico by providing relief from the obligation to pay royalty on certain federal leases up to certain specified production volumes. Our only leases affected by this dispute are Garden Banks Blocks 667, 668 and 669 ("Gunnison"). On May 2, 2006, the MMS issued an order that superseded and replaced the December 2005 order, and claimed that royalties on gas production are due for 2003 in addition to oil and gas production in 2004. The May 2006 order also seeks interest on all royalties allegedly due. We filed a timely notice of appeal with respect to both MMS orders. We received an additional order from the MMS dated September 30, 2008 stating that the price thresholds for oil and gas were exceeded for 2005, 2006 and 2007 production, and that royalties and interest are payable. We appealed that order on the same basis that we appealed the prior MMS orders. Other operators in the Deep Water Gulf of Mexico who have received notices similar to ours are seeking royalty relief under the DWRRA, including Kerr-McGee, the operator of Gunnison. In March of 2006, Kerr-McGee filed a lawsuit in federal district court challenging the enforceability of price thresholds in certain deepwater Gulf of Mexico leases, including ours. We do not anticipate that the MMS director will issue decisions in our or the other companies' administrative appeals until the Kerr-McGee litigation has been resolved in a final decision.

On October 30, 2007, the federal district court in the Kerr-McGee case entered judgment in favor of Kerr-McGee and held that the Department of the Interior exceeded its authority by including the price thresholds in the subject leases. The government filed a notice of appeal of that decision on December 21, 2007. On January 12, 2009, the United States Court of Appeals for the Fifth Circuit affirmed the decision of the district court in favor of Kerr-McGee, holding that the DWRRA unambiguously provides that royalty suspensions up to certain production volumes established by Congress apply to leases that qualify under the DWRRA. As a result of our dispute with the MMS, we have recorded reserves for the disputed royalties (and any other royalties that may be claimed from the Gunnison leases), plus interest, for our portion of the Gunnison related MMS claim. The total reserved amount at December 31, 2008 was approximately $69.7 million and was included in Other Long Term Liabilities in the accompanying consolidated balance sheet included herein. As a result of this ruling, we believe that any future payment of these contractual royalties is not probable. Accordingly, in the first quarter of 2009 our operating results will include a $69.7 million gain from the reversal of these previously reserved amounts associated with the potential payment of the disputed royalties.

During the fourth quarter of 2006, Horizon received a tax assessment from the Servicio de Administracion Tributaria (SAT), the Mexican taxing authority, for approximately $23 million related to fiscal 2001, including penalties, interest and monetary correction. The SAT's assessment claims unpaid taxes related to services performed by the Horizon subsidiaries that CDI acquired when it acquired Horizon. CDI believes under the Mexico and United States double taxation treaty that these services are not taxable and the tax assessment itself is invalid. On February 14, 2008, CDI received notice from the SAT upholding the original assessment. On April 21, 2008, CDI filed a petition in Mexico tax court disputing the assessment. We believe that CDI's position is supported by law and CDI intends to vigorously defend its position. However, the ultimate outcome of this litigation and CDI's potential liability from this assessment, if any, cannot be determined at this time. Nonetheless, an unfavorable outcome with respect to the Mexico tax assessment could have a material adverse affect on our financial position and results of operation. Horizon's 2002 through 2007 tax years remain subject to examination by the appropriate governmental agencies for Mexico tax purposes, with 2002 through 2004 currently under audit.

Item 4. Submission of Matters to a Vote of Security Holders.

None.

Executive Officers of the Company

The executive officers of Helix are as follows:

Name	Age	Position
Owen Kratz	54	President and Chief Executive Officer and Director

Bart H. Heijermans	42	Executive Vice President and Chief Operating Officer
Robert P. Murphy	50	Executive Vice President — Oil & Gas
Anthony Tripodo	56	Executive Vice President and Chief Financial Officer
Alisa B. Johnson	51	Executive Vice President, General Counsel and Corporate Secretary
Lloyd A. Hajdik	43	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 Chairman 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) Brockport.

Bart H. Heijermans became Executive Vice President and Chief Operating Officer of Helix in September 2005. Prior to joining Helix, Mr. Heijermans worked as Senior Vice President Offshore and Gas Storage for Enterprise Products Partners, L.P. from 2004 to 2005 and previously from 1998 to 2004 was Vice President Commercial and Vice President Operations and Engineering for GulfTerra Energy Partners, L.P. Before his employment with GulfTerra, Mr. Heijermans held various positions with Royal Dutch Shell in the United States, the United Kingdom and the Netherlands. Mr. Heijermans received a Master of Science degree in Civil and Structural Engineering from the University of Delft, the Netherlands and is a graduate of the Harvard Business School Executive Program.

Robert P. Murphy was elected as Executive Vice President — Oil & Gas of Helix on February 28, 2007, and as President and Chief Operating Officer of Helix Oil & Gas, Inc., a wholly owned subsidiary, on November 29, 2006. Mr. Murphy joined Helix on July 1, 2006 when Helix acquired Remington Oil & Gas Corporation, where Mr. Murphy served as President, Chief Operating Officer and was on the Board of Directors. Prior to joining Remington, Mr. Murphy was Vice President — Exploration of Cairn Energy USA, Inc, of which Mr. Murphy also served on the Board of Directors. Mr. Murphy received a Bachelor of Science degree in Geology from The University of Texas at Austin, and has a Master of Science in Geosciences from the University of Texas at Dallas.

Anthony Tripodo was elected as Executive Vice President and Chief Financial Officer on June 28, 2008. Mr. Tripodo oversees the finance, treasury, accounting, tax, information technology, administration 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 also serves as a director of TXCO Resources Inc., an independent oil and gas enterprise with operations primarily in Texas, onshore Gulf Coast region and Western Oklahoma. He 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 Compay. Ms. Johnson has been involved with the energy industry for over 18 years. Prior to joining Helix, Ms. Johnson worked for Dynegy Inc. for nine years, at which company she held various legal positions, 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 closing sale prices per share of our common stock:

	Common Stock Prices	
	High	Low
2007		
First Quarter	$ 37.45	$ 28.00
Second Quarter	$ 41.44	$ 35.52
Third Quarter	$ 42.95	$ 35.25
Fourth Quarter	$ 46.84	$ 39.08
2008		
First Quarter	$ 42.83	$ 28.26
Second Quarter	$ 41.81	$ 30.54
Third Quarter	$ 41.68	$ 28.47
Fourth Quarter	$ 25.16	$ 3.91
2009		
First Quarter(1)	$ 9.47	$ 2.21

(1) Through February 27, 2009

On February 27, 2009, the closing sale price of our common stock on the NYSE was $3.11 per share. As of February 22, 2009, there were an estimated 322 registered shareholders and 36,751 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, 2003 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 Corp, W&T Offshore, Inc. and Mariner Energy, Inc. The returns of each member of the Peer Group have been weighted according to each individual company's equity market capitalization as of December 31, 2008 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, 2003 in our common stock at the closing price on that date price and on December 31, 2003 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 — (40.0%); the Peer Group — 52.0%; the OSX — 33.3%; and S&P 500- (10.2%). These results are not necessarily indicative of future performance.

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

	As of December 31,					
	2003	2004	2005	2006	2007	2008
Helix	$ 100.0	$ 169.0	$ 297.6	$ 260.1	$ 344.1	$ 60.0
Peer Group Index	$ 100.0	$ 126.8	$ 222.8	$ 251.0	$ 417.3	$ 152.0
Oil Service Index	$ 100.0	$ 132.5	$ 195.6	$ 215.9	$ 326.9	$ 133.3
S&P 500	$ 100.0	$ 110.7	$ 116.1	$ 134.2	$ 141.6	$ 89.8

Source: Bloomberg

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced program	(d) Maximum value of shares that may yet be purchased under the program (in thousands)
October 1 to October 31, 2008(1)	1,439	$ 9.55		$ N/A
November 1 to November 30, 2008		$		N/A
December 1 to December 31, 2008		$		N/A
	1,439	$ 9.55		$

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

Item 6. Selected Financial Data.

The financial data presented below for each of the five years ended December 31, 2008, 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 Form 10-K.

	Year Ended December 31,				
	2008	2007(1)	2006(2)	2005	2004
	(In thousands, except per share amounts)				
Net revenues	$2,148,349	$1,767,445	$1,366,924	$799,472	$543,392
Gross profit	380,668	513,756	515,408	283,072	171,912
Operating income (loss) (3)	(445,557)	412,744	398,645	221,687	123,031
Equity in earnings of investments	31,971	19,698	18,130	13,459	7,927
Net income (loss)(2)	(630,848)	320,478	347,394	152,568	82,659
Preferred stock dividends and accretion	3,192	3,716	3,358	2,454	2,743
Net income (loss) applicable to common shareholders(4)	(634,040)	316,762	344,036	150,114	79,916
Earnings (loss) per common share (5):					
Basic	$ (6.99)	$ 3.52	$ 4.07	$ $ 1.94	$ 1.05
Diluted	$ (6.99)	$ 3.34	$ 3.87	$ 1.86	$ 1.03
Weighted average shares outstanding(5):					
Basic	90,650	90,086	84,613	77,444	76,409
Diluted	90,650	95,938	89,874	82,205	79,062

(1) Includes effect of the Horizon acquisition since December 11, 2007. See Item 8. Financial Statements and Supplementary Data "— Note 5 — Acquisition of Horizon Offshore, Inc." for additional information.

(2) Includes effect of the Remington acquisition since July 1, 2006. See Item 8. Financial Statements and Supplementary Data "— Note 4 — Acquisition of Remington Oil and Gas Corporation" for additional information.

(3) Includes $907.6 million of impairment charges to reduce goodwill and other indefinite lived intangible assets ($715 million) and certain oil and gas properties ($192.6 million) to their estimated fair value in fourth quarter of 2008. Total impairment charges totaled $930.7 million, $64.1 million, $0.8 million and $3.9 million for each of the years ending December 31, 2008, 2007, 2005 and 2004, respectively. There were no impairments in 2006. Also includes exploration expenses totaling $32.9 million ($27.1 million in fourth quarter of 2008) in 2008, $26.7 million in 2007, $43.1 million in 2006, $6.5 million in 2005. We did not have any exploration expense in 2004.

(4) 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 as related to its acquisition of Horizon and its initial public offering. These gains did not effect our current or future

cash flow.

(5) All earnings per share information reflects a two-for-one stock split effective as of the close of business on December 8, 2005.

	Year Ended December 31,				
	2008(1)	2007(2)	2006(3)	2005	2004
	(In thousands, except per share amounts)				
Working capital	$ 277,509	$ 48,290	$ 310,524	$ 120,388	$ 112,799
Total assets	5,070,338(1)	5,452,353	4,290,187	1,660,864	1,038,758
Long-term debt and capital leases (including current maturities)	2,062,042	1,800,387	1,480,356	447,171	148,560
Minority interest	322,627	263,926	59,802		
Convertible preferred stock	55,000(4)	55,000	55,000	55,000	55,000
Shareholders' equity	1,170,645(1)	1,846,556	1,525,948	629,300	485,292

(1) 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. See Item 8. Financial Statements and Supplementary Data "— Note 2 — Summary of Significant Accounting Policies." for additional information.

(2) Includes effect of the Horizon acquisition since December 11, 2007. See Item 8. Financial Statements and Supplementary Data "— Note 5 — Acquisition of Horizon Offshore, Inc." for additional information.

(3) Includes effect of the Remington acquisition since July 1, 2006. See Item 8. Financial Statements and Supplementary Data "— Note 4— Acquisition of Remington Oil and Gas Corporation" for additional information.

(4) The holder of the convertible preferred stock redeemed $30 million of our convertible preferred stock into 5.9 million shares of our common stock in January 2009. See Item 8. Financial Statements and Supplementary Data "— Note 13 — Convertible Preferred Stock" for additional information.

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

The following management's discussion and analysis should be read in conjunction with our historical consolidated financial statements and their located in Item 8. "Financial Statements and Supplementary Data" of this 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 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 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

In December 2008, we announced the intention to focus and shape the future direction of the Company around our deepwater construction and well intervention services. We intend to achieve this strategic focus by seeking and evaluating strategic opportunities to:

1) Divest all or a portion of our oil and gas assets;
2) Divest our ownership interests in one or more of our production facilities; and
3) Dispose of our remaining interest in our majority owned subsidiary, CDI.

We have engaged financial advisors to assist us in these efforts. The current economic and financial market conditions may affect the timing of any strategic dispositions by us and will require a degree of patience in order to execute any transactions. As a result, we are unable to be specific with respect to a timetable for any disposition, but we intend to aggressively focus on reducing debt levels through monetization of non-core assets and allocation of free cash flow in order to accelerate our strategic goals.

Consistent with this strategy, in December 2008 we announced the sale of our 17.5% non-operating working interest in the Bass Lite oil and gas field for $49 million in gross proceeds and in January 2009 we entered into a stock repurchase agreement with Cal Dive that resulted in us selling CDI approximately 13.6 million of CDI common shares held by us for $86 million in gross proceeds. This sale reduced our ownership interest in CDI to the current approximate 51%. We owned approximately 57% of CDI at December 31, 2008.

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

Economic Outlook and Industry Influences

The recent economic downturn and weakness in the equity and credit capital markets has led to increased uncertainty regarding the outlook of the global economy. This uncertainty coupled with the probable decrease in the near-term global demand for oil and gas has resulted in commodity price declines over the second half of 2008, with significant declines occurring in the fourth quarter of 2008. Declines in oil and gas prices negatively impact our operating results and cash flow. We believe that these events have contributed to the significant decline in our stock price and corresponding market capitalization. In the fourth quarter of 2008, the declines in our stock price and the prices of oil and natural gas, were considered in association with our annual impairment assessment of goodwill as of November 1, 2008, at which time, we were required to assess the fair value of our goodwill, indefinite-lived intangible assets and certain of oil and gas properties that resulted in us recording an aggregate of $907.6 million of impairment charges ($715 million for goodwill and indefinite lived intangible assets and $192.6 million for oil and gas property impairments) (Note 2). The aggregate of all impairment charges for 2008 was $930.6 million. Further, our contracting services also may be negatively impacted by declining commodity prices as such may cause our customers, primarily oil and gas companies, to curtail or eliminate capital spending. At the moment, it is still too soon to predict to what extent current events may affect our overall activity levels in 2009 and beyond. The long-term fundamentals for our business remain generally favorable as the need for the continual replenishment of oil and gas production should drive the demand for our services. In addition, as our subsea construction operations primarily support capital projects with long lead times, that are less likely to be impacted by temporary economic downturns. We have hedged approximately 73% of our anticipated production for 2009 with a combination of forward sale and financial hedge contracts. The prices for these contracts are significantly higher than the prices for both crude oil and natural gas as of December 31, 2008 and as of the time of this filing on March 2, 2009. If the prices for crude oil and natural gas do not increase 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 2010 and beyond, perhaps significantly, absent offsetting increases in production amounts.

In light of the current credit crisis, in October 2008, we drew down an additional $175 million on our Revolving Credit Facility to ensure adequate and readily available liquidity to mitigate the cash flow impacts of production shut-in from Hurricanes Gustav and Ike, to fund ongoing capital projects and for hurricane remediation and repair costs. After this draw down, we had approximately $44 million (approximately $59 million as of February 27, 2009) of additional capacity remaining under our Revolving Credit Facility (including letters of credit). Further, we have reduced our planned capital expenditures for 2009 to include primarily the completion of major vessel construction projects and limited oil and gas expenditures. If we successfully implement the business plan outlined above, we believe we have sufficient liquidity without incurring additional indebtedness beyond the existing capacity under the Revolving Credit Facility.

Our business is substantially dependent upon the condition of the oil and natural gas industry and, in particular, the willingness of oil and natural gas companies to make capital expenditures for offshore exploration, drilling and production operations. The level of capital expenditures generally depends on the prevailing views of future oil and natural gas prices, which are influenced by numerous factors, including but not limited to:

- worldwide economic activity, including available access to global capital and capital market;
- 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 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.

Global economic conditions have deteriorated significantly over the past year with declines in the oil and gas market accelerating during the fourth quarter of 2008. Predicting the timing of any recovery is subjective and highly uncertain. Although we are currently is a recession, 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; (2) peaking global production rates; (3) globalization of the natural gas market; (4) increasing number of mature and small reservoirs; (5) increasing ratio of contribution to global production from marginal fields; (6) increasing offshore activity, particularly in Deepwater; and (7) 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 (7) 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 have an equity stake.

Activity Summary

Over the last few years we continued to evolve our model by completing a variety of transactions and events that have had, and we believe will continue to have, significant impacts on our results of operations and financial condition. In 2005, we substantially increased the size of our Shelf Contracting fleet and deepwater pipelay fleet through the acquisition of assets from Torch Offshore, Inc. and Acergy US Inc. for a combined purchase price of $210.2 million. We also acquired a significant mature property package in the Gulf of Mexico OCS from Murphy Oil Corporation for $163.5 million cash and assumption of abandonment liability of $32 million. Finally, we established our Reservoir and Well Technology Services group through the acquisition of Helix Energy Limited for $32.7 million and the assumption of $7.5 million of liabilities. In 2006, we acquired Remington, an exploration, development and production company, for approximately $1.4 billion in cash and Helix common stock and the assumption of $358.4 million of liabilities. In March 2006m, we changed our name from Cal Dive International, Inc. to Helix Energy Solutions Group, Inc., leaving the “Cal Dive” name to our Shelf Contracting subsidiary, 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 which will significantly expand our contracting services capabilities: conversion of the Caesar into a deepwater pipelay vessel, upgrading of the Q4000 to include drilling capability, conversion of a ferry vessel into a DP floating production unit (Helix Producer I) and construction of a multi-service DP dive support/well intervention vessel (Well Enhancer). 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 (see “Oil and Gas Operations” in Item 2. “Properties” elsewhere in this Annual Report). Initial sustained production from Bushwood commenced in January 2009.

In December 2007, Cal Dive acquired Horizon for approximately $650 million. CDI issued an aggregate of approximately 20.3 million shares of its common stock and paid approximately $300 million in cash in the merger. The cash portion of the merger consideration was paid from CDI’s cash on hand and from borrowings under its $675 million credit facility consisting of a $375 million senior secured term loan and a $300 million senior secured revolving credit facility, each of which is non-recourse to Helix. As a result of CDI’s equity issued, we recorded a $98.6 million gain, net of $53.1 million of taxes. The non-cash gain was calculated as the difference in the value of our investment in CDI immediately before and after CDI’s stock issuance.

Results of Operations

Our business consists of contracting services and oil and gas operations. We have disaggregated our contracting services operations into three reportable segments in accordance with SFAS No. 131 “Disclosures about Segments of an Enterprise and Related Information”. As a result, our reportable segments consist of the following: Contracting Services, Shelf Contracting, Production Facilities, and Oil and Gas. The Contracting Services segment includes operations such as deepwater pipelay, well operations, robotics and reservoir and well technology services. The Shelf Contracting segment represent the results and operations of Cal Dive, in which we owned 57.2% at December 31, 2008 and currently own approximately 51%. All material intercompany transactions between the segments have been eliminated in our consolidated financial statements, including our consolidated results of operations.

Comparison of Years Ended December 31, 2008 and 2007

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

	Year Ended December 31,		
	2008	2007	Increase/ (Decrease)
Revenues (in thousands) –			
Contracting Services	$ 996,535	$ 708,833	$ 287,702
Shelf Contracting(1)	856,906	623,615	233,291
Oil and Gas	545,853	584,563	(38,710)
Intercompany elimination	(250,945)	(149,566)	(101,379)
	$2,148,349	$1,767,445	$ 380,904
Gross profit (loss) (in thousands) –			
Contracting Services	$ 213,427	$ 188,505	$ 24,922
Shelf Contracting(1)	254,007	227,398	26,609
Oil and Gas(2)	(60,601)	120,861	(181,462)
Intercompany elimination	(26,165)	(23,008)	(3,157)
	$ 380,668	$ 513,756	$ (133,088)
Gross Margin –			
Contracting Services	21%	27%	(6)pts
Shelf Contracting(1)	30%	36%	(6)pts
Oil and Gas (2)	(11)%	21%	(32)pts
Total company	(18)%	29%	(47)pts
Number of vessels(3)/ Utilization(4) –			
Contracting Services:			
Pipelay	9/92%	6/79%	
Well operations	2/70%	2/71%	
ROVs	46/73%	39/78%	
Shelf Contracting	30/60%	34/65%	

1) Represented by our consolidated, majority owned subsidiary, CDI. At December 31, 2008 and 2007, our ownership interest in CDI was approximately 57.2% and 58.5%, respectively. Our interest in CDI decreased to approximately 51% in January 2009.

2) Includes asset impairment charges of oil and gas properties totaling $215.7 million ($192.6 million in fourth quarter of 2008). These impairment charges do not have any impact on current or future cash flow.

3) Represents 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.

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, 2008 and 2007 were as follows (in thousands):

	Year Ended December 31,		
	2008	2007	Increase/ (Decrease)
Contracting Services	$ 195,541	$ 115,864	$ 79,677
Shelf Contracting	55,404	33,702	21,702
	$ 250,945	$ 149,566	$ 101,379

Intercompany segment profit (which only relates to intercompany capital projects) during the years ended December 31, 2008 and 2007 were as follows (in thousands):

	Year Ended December 31,		
	2008	2007	Increase/ (Decrease)
Contracting Services	$ 21,099	$ 10,026	$ 11,073
Shelf Contracting	5,066	12,982	(7,916)
	$ 26,165	$ 23,008	$ 3,157

As disclosed in Item 2 "Properties" elsewhere in this Annual Report, virtually all of our oil and gas operations are located in the U.S. Gulf of Mexico. We have one property located offshore of the United Kingdom, Camelot, that is capable of production but has been shut-in since the third quarter of 2008. Revenues associated with our U.K oil and gas operations totaled $3.9 million in 2008 and $2.7 million in 2007 on production volumes of 0.3 Bcfe and 0.6 Bcfe, respectively. We had no production from U.K properties in 2006. The total operating costs associated with our U.K oil and gas operations totaled $4.1 million in 2008, $7.3 million in 2007 and $4.9 million in 2006.

The following table details various financial and operational highlights related to our Oil and Gas segment for the periods presented (U.S. operations only as U.K. operations were immaterial for the periods presented, see above):

	Year Ended December 31,		
	2008	2007	Increase/ Decrease
Oil and Gas information–			
Oil production volume (MBbls)	2,751	3,723	(972)
Oil sales revenue (in thousands)	$ 253,656	$ 251,955	$ 1,701
Average oil sales price per Bbl (excluding hedges)	$ 98.61	$ 70.17	$ 28.44
Average realized oil price per Bbl (including hedges)	$ 92.22	$ 67.68	$ 24.54
Increase (decrease) in oil sales revenue due to:			
Change in prices (in thousands)	$ 91,360		
Change in production volume (in thousands)	(89,659)		
Total increase in oil sales revenue (in thousands)	$ 1,701		
Gas production volume (MMcf)	30,490	42,163	(11,673)
Gas sales revenue (in thousands)	$ 283,269	$ 324,282	$ (41,013)
	$ 9.48	$ 7.46	$ 2.02

Average gas sales price per mcf (excluding hedges)			
Average realized gas price per mcf (including hedges)	$ 9.29	$ 7.69	$ 1.60
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$ 67,441		
Change in production volume (in thousands)	(108,454)		
Total increase in gas sales revenue (in thousands)	$ (41,013)		
Total production (MMcfe)	46,993	64,500	(17,507)
Price per Mcfe	$ 11.43	$ 8.93	$ 2.50

	Year Ended December 31,		
	2008	2007	Increase/ Decrease
Oil and Gas revenue information (in thousands)-			
Oil and gas sales revenue	$ 536,925	$ 576,237	$ (39,312)
Miscellaneous revenues(1)	$ 5,058	$ 5,667	$ (609)

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

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

	Year Ended December 31,			
	2008		2007	
	Total	Per Mcfe	Total	Per Mcfe
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$ 80,710	$ 1.72	$ 80,410	$ 1.25
Workover	28,982	0.62	11,840	0.18
Transportation	5,095	0.11	4,560	0.07
Repairs and maintenance	20,731	0.44	12,191	0.19
Overhead and company labor	4,798	0.10	9,031	0.14
Total	$ 140,316	$ 2.99	$ 118,032	$ 1.83
Depletion and amortization	$ 185,373	$ 3.94	$ 217,382	$ 3.37
Abandonment	15,985	0.34	21,073	0.33
Accretion	12,771	0.27	10,701	0.17
Impairments (3)	215,675	4.59	64,072	0.99
	$ 429,804	$ 9.14	$ 313,228	$ 4.86

(1) Excludes exploration expense of $32.9 million and $26.7 million for the years ended December 31, 2008 and 2007, respectively. Exploration expense is not a component of lease operating expense. Also excludes the impairment charge to goodwill of $704.3 million in fourth quarter of 2008.

(2) Includes production taxes.

(3) Includes impairment charges for certain oil and gas properties totaling $215.7 million ($192.6 million in fourth quarter of 2008).

Revenues. During the year ended December 31, 2008 our consolidated net revenues increased by 22% compared to 2007. Contracting Services gross revenues increased 41% over 2007 amounts primarily reflecting the following:

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the addition of two chartered subsea construction vessels as well as an overall increase in utilization of our subsea construction vessels;

§ commencing performance of several longer term contracts;

§ increases in the utilization and rates realized for our well operations vessels;

§ strong performance by our robotics division driven by a higher number of ROVs in our fleet and additional services required following Hurricanes Gustav and Ike; and

§ increased sales by our Shelf Contracting business (see below), resulting from its acquisition of Horizon in December 2007 and increased work following Hurricanes Gustav and Ike .

Our increases were partially offset by the following negative factors:

§ an increase in the number of out-of-service days for the Q4000 associated with marine and drilling upgrades. The Q4000 was out of service for most of the first half of 2008;
§ weather related downtime associated with Hurricanes Gustav and Ike.

Gross revenues for our Shelf Contracting business increased 37% in 2008 compared to 2007 primarily reflecting the revenue contribution of the Horizon assets that were acquired in December 2007 partially offset by lower vessel utilization related to winter seasonality and harsh weather conditions which continued into May 2008, and weather downtime associated with Hurricanes Gustav and Ike. Following the storm, our Shelf Contracting revenues benefitted from the increased scope of work associated with the storms including inspections, repairs and reclamation projects.

Oil and Gas revenues decreased 7% during 2008 as compared to the prior year. The decrease is primarily associated with the loss of production following the shut-in of many of our oil and gas properties following Hurricanes Gustav and Ike. Our production rates in 2008 were 27% lower than the same period last year; however our current net daily production is approximately 90% of pre-storm production volumes after adjusting for the sale of one major deepwater property in December 2008. The decrease in our revenues was partially offset by substantially higher oil and natural gas prices realized over the amounts received in 2007, which reflects near historical high prices for both oil and natural gas over the first half of 2008. Prices of both oil and natural gas decreased significantly during the second half of 2008, with price reductions accelerating in the fourth quarter of 2008.

Gross Profit. The Contracting Services gross profit increase was primarily attributable to improved contract pricing for the well operations and ROV divisions. These increases were partially offset by lower margins realized on certain longer term deepwater pipelay projects reflecting the delays in delivery of the Ceasar and processing of certain change orders which prevented revenue recognition under the percentage-of-completion method (Note 2). We also recorded approximately $9.8 million of estimated losses on two contracts in which we believe the future revenue benefits will be exceeded by the estimated future costs to service the contracts (Note 2). The gross profit increase within Shelf Contracting was primarily attributable to the initial deployment of Horizon's assets that were acquired in December 2007 and additional work following Hurricanes Gustav and Ike, offset by increased depreciation associated with Horizon assets and weather-related delays over the first five months of 2008 and during Hurricanes Gustav and Ike. Our 2007 Shelf Contracting operations were adversely effected by an higher number of out-of-service days referred to above, lower vessel utilization as a result of seasonal weather in the fourth quarter 2007, and increased depreciation and deferred drydock amortization.

The decrease in the gross profit for our oil and gas operations in 2008 as compared to 2007 reflects the following key factors :

- impairment expense of approximately $215.7 million ($192.6 million recorded in the fourth quarter of 2008) related to our proved oil and gas properties primarily as a result of downward reserve revisions reflecting lower oil and natural gas prices, weak end of life well performance for some of our domestic properties, fields lost as a result of Hurricanes Gustav and Ike and the reassessment of the economics of some of our marginal fields in light of our announced business strategy to exit the oil and gas exploration and production business; we also recorded a $14.6 million asset impairment charge associated with the Devil's Island Development well (Garden Banks Block 344) that was determined to be non-commercial in January 2008. Asset impairment expense in 2007 totaled $64.1 million, which included $20.9 million for the costs incurred on the Devil's Island well through December 31, 2007.

- an increase of $32.0 million in depletion expense in 2008 because of lower production which is primarily attributed to the effects Hurricanes Gustav and Ike had on our production during the latter part of the yea. This decrease was partially offset by higher rates resulting from a reduction in estimated proved reserves for a number of or producing fields at December 31, 2008.

- approximately $8.8 million of exploration expense (all in fourth quarter of 2008) compared to $9.0 million in 2007 related to reducing the carrying value of our unproved properties primarily due to management's assessment that exploration activities for certain properties will not commence prior to the respective lease expiration dates;

- approximately $16.0 million of plug and abandonment overruns primarily related to properties damaged by the hurricanes, partially offset by insurance recoveries of $7.8 million; and

- approximately $18.8 million of dry hole exploration expense reflecting the conclusion that two exploratory wells previously classified as suspended wells (Note 7) no longer met the requirements to continue to be capitalized primarily as a result of the discontinuing of plans to progress the development of these wells in light of our announcement in December 2008 of our intention to pursue a sale of all or a portion of our oil and gas assets. In 2007, our dry hole expense totaled $10.3 million, of which $5.9 million was related to our South Marsh Island Block 123 #1 well.

Goodwill and other intangible asset impairments. In the fourth quarter of 2008 we recorded a $704.3 million of impairment charge to eliminate our remaining oil and gas goodwill following our annual assessment of goodwill, which took into account the significant decrease in our common stock price as well as the stock prices of our identified peers and the rapid reduction in oil and natural gas commodity prices. For our Contracting Services segment, we recorded an $8.3 million impairment charge to eliminate the goodwill for one of our reporting units and a related $2.4 million impairment charge for an indefinite life asset (trademark). We separately recorded $8.1 million of reductions of goodwill associated with dispositions of oil and gas properties in 2008, which are included as a component of the gain or loss on sale of assets, net as discussed below.

Gain on Sale of Assets, Net. The net gain on sale of assets increased by $23.1 million during 2008 as compared to 2007. In 2008 our oil and gas property sales included:

• $91.6 million gain related to the sale of a 30% working interest in the Bushwood discoveries (Garden Banks Blocks 463, 506 and 507) and East Cameron Blocks 371 and 381;

• $11.9 million loss related to the sale of all our onshore properties; included in the cost basis of our onshore properties was goodwill of $8.1 million; and

• $6.7 million loss related to the sale of our interest in the Bass Lite field in December 2008; there was no goodwill associated with this sale as all goodwill was previously written off. The sale of the remainder (approximately 10%) of our original 17.5% interest closed in January 2009 and will be reflected in our first-quarter 2009 results.

On September 30, 2007, we sold a 30% working interest in the Phoenix oilfield (Green Canyon Blocks 236/237), the Boris oilfield (Green Canyon Block 282) and the Little Burn oilfield (Green Canyon Block 238) to Sojitz GOM Deepwater, Inc. ("Sojitz") for a cash payment of $51.2 million and recognized a gain of $40.4 million in 2007. We also recognized the following gains in 2007:

• $2.4 million related to the sale of a mobile offshore production unit;

• $1.6 million related to the sale of 50% interest in Camelot, which is located offshore of United Kingdom; and

• $3.9 million related to the sale of assets owned by CDI.

Selling and Administrative Expenses. Selling and administrative expenses of $184.7 million in 2008 were $33.3 million higher than the $151.4 million incurred in 2007. The increase was due primarily to higher overhead (primarily related to CDI's Horizon acquisition) to support our growth. We also recognized approximately $7.4 million of expenses related to the separation agreements between the Company and two of its former executive officers (Note 22). Selling and administrative expenses as a percent of revenues were approximately 8.6% for both 2008 and 2007.

Equity in Earnings of Investments, Net of Impairment Charge. Equity in earnings of investments increased $12.3 million during 2008 as compared to 2007. Equity in earnings related to our 20% investment in Independence Hub increased $9.3 million as we reached mechanical completion in March 2007 and began receiving demand fees and tariffs as production began in the third quarter of 2007. In addition, equity in earnings of our 50% investment in Deepwater Gateway decreased by $3.5 million in 2008 as compared to 2007 due to downtime at the Marco Polo TLP following Hurricanes Gustav and Ike. These increases were offset by second quarter 2007 equity losses from CDI's 40% investment in Offshore Technology Solutions Limited ("OTSL") and a related non-cash asset impairment charge together totaling $11.8 million.

Net Interest Expense and Other. Net interest and other expense increased to $81.4 million in 2008 as compared to $59.4 million in the prior year. Gross interest expense of $129.2 million during 2008 was higher than the $100.4 million incurred in 2007 because of higher levels of indebtedness as a result of our Senior Unsecured Notes and CDI's term loan, both of which closed in December 2007. Offsetting the increase in interest expense was $42.1 million of capitalized interest and $2.5 million of interest income in 2008, compared with $31.8 million of capitalized interest and $9.5 million of interest income in 2007. We expect interest expense to decrease in 2009 as a result of lower expected interest rates on our variable rate debt instruments. See Note 11 for detailed description

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of these notes. Our other income (expense) includes gains (losses) associated with transactions denominated in foreign currencies. Our foreign currency gains (losses) totaled ($9.8) million in 2008 and ($0.5) million in 2007.

Provision for Income Taxes. Income taxes decreased to $90.0 million in 2008 compared to $174.9 million in the prior year. This decrease is primarily due to lower profitability in 2008. The effective tax rate of (18.2)% is not representative because of the $715.0 million non-deductible goodwill and indefinite lived intangible assets impairment charge as discussed above. Excluding the goodwill and other intangible asset impairments, the effective tax rate of 40.9% for 2008 was higher than the 33.3% effective tax rate for same period 2007 primarily reflecting the additional deferred tax expense recorded as a result of the increase in the equity earnings of CDI in excess of our tax basis. Further, the allocation of goodwill to the cost basis for the oil and gas properties sales prior to the fourth quarter of 2008 was not deductible for tax purposes. See Note 12 for additional information regarding income taxes.

Comparison of Years Ended December 31, 2007 and 2006

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

	Year Ended December 31,		
	2007	2006	Increase/ (Decrease)
Revenues (in thousands) –			
Contracting Services	$ 708,833	$ 485,246	$ 223,587
Shelf Contracting(1)	623,615	509,917	113,698
Oil and Gas	584,563	429,607	154,956
Intercompany elimination	(149,566)	(57,846)	(91,720)
	$1,767,445	$1,366,924	$ 400,521
Gross profit (in thousands) –			
Contracting Services	$ 188,505	$ 138,516	$ 49,989
Shelf Contracting(1)	227,398	222,530	4,868
Oil and Gas	120,861	162,386	(41,525)
Intercompany elimination	(23,008)	(8,024)	(14,984)
	$ 513,756	$ 515,408	$ (1,652)
Gross Margin –			
Contracting Services	27%	29%	(2)pts
Shelf Contracting(1)	36%	44%	(8)pts
Oil and Gas	21%	38%	(17)pts
Total company	29%	38%	(9)pts
Number of vessels(2)/ Utilization(3) –			
Contracting Services:			
Pipelay	6/79%	4/87%	
Well operations	2/71%	2/81%	
ROVs	39/78%	31/76%	
Shelf Contracting	34/65%	25/84%	

1) Represented by our consolidated, majority owned subsidiary, CDI. At December 31, 2007 and 2006, our ownership interest in CDI was approximately 58.5% and 73.0%, respectively.

2) Represents 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.

3) 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, 2007 and 2006 were as follows (in thousands):

	Year Ended December 31,		
	2007	2006	Increase/ (Decrease)
Contracting Services	$ 115,864	$ 42,585	$ 73,279
Shelf Contracting	33,702	15,261	18,441
	$ 149,566	$ 57,846	$ 91,720

Intercompany segment profit (which only relates to intercompany capital projects) during the years ended December 31, 2007 and 2006 were as follows (in thousands):

	Year Ended December 31,		
	2007	2006	Increase/ (Decrease)
Contracting Services	$ 10,026	$ 2,460	$ 7,566
Shelf Contracting	12,982	5,564	7,418
	$ 23,008	$ 8,024	$ 14,984

The following table details various financial and operational highlights related to our Oil and Gas segment for the periods presented (U.S. operations only as U.K. operations were immaterial for the periods presented):

	Year Ended December 31,		
	2007	2006	Increase/ Decrease
Oil and Gas information–			
Oil production volume (MBbls)	3,723	3,400	323
Oil sales revenue (in thousands)	$ 251,955	$ 205,415	$ 46,540
Average oil sales price per Bbl (excluding hedges)	$ 70.17	$ 61.08	$ 9.09
Average realized oil price per Bbl (including hedges)	$ 67.68	$ 60.41	$ 7.27
Increase in oil sales revenue due to:			
Change in prices (in thousands)	$ 24,699		
Change in production volume (in thousands)	21,841		
Total increase in oil sales revenue (in thousands)	$ 46,540		
Gas production volume (MMcf)	42,163	27,949	14,214
Gas sales revenue (in thousands)	$ 324,282	$ 219,674	$ 104,608
Average gas sales price per mcf (excluding hedges)	$ 7.46	$ 7.46	$
Average realized gas price per mcf (including hedges)	$ 7.69	$ 7.86	$ (0.17)
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$ (4,718)		
Change in production volume (in thousands)	109,326		
Total increase in gas sales revenue (in thousands)	$ 104,608		
Total production (MMcfe)	64,500	48,349	16,151
Price per Mcfe	$ 8.93	$ 8.79	$ 0.14
Oil and Gas revenue information (in thousands)-			
Oil and gas sales revenue	$ 576,237	$ 425,089	$ 151,148

Miscellaneous revenues(1)	$	5,667	$	4,518	$	1,149

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

The following table highlights certain relevant expense items in total (in thousands) and on a cost per Mcfe of production basis:

	Year Ended December 31,			
	2007		2006	
	Total	Per Mcfe	Total	Per Mcfe
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$ 80,410	$ 1.25	$ 50,930	$ 1.05
Workover	11,840	0.18	11,462	0.24
Transportation	4,560	0.07	3,174	0.07
Repairs and maintenance	12,191	0.19	13,081	0.27
Overhead and company labor	9,031	0.14	10,492	0.22
Total	$ 118,032	$ 1.83	$ 89,139	$ 1.85
Depletion and amortization	$ 217,382	$ 3.37	$ 126,350	$ 2.61
Abandonment	21,073	0.33		
Accretion	10,701	0.17	8,617	0.18
Impairments	64,072	0.99		
	$ 313,228	$ 4.86	$ 134,967	$ 2.79

(1) Excludes exploration expense of $26.7 million and $43.1 million for the years ended December 31, 2007 and 2006, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

Revenues. During the year ended December 31, 2007, our revenues increased by 29% as compared to 2006. Contracting Services revenues increased primarily due to improved contract pricing for the pipelay, well operations and ROV divisions. Shelf Contracting revenues increased primarily as a result of the initial deployment of certain assets we acquired through the Torch, Acergy and Fraser acquisitions that came into service subsequent to the first quarter of 2006 as well as the Horizon assets acquired in late 2007. These increases were partially offset by two vessels CDI did not operate (one owned and one chartered) in 2007 that were in operation in 2006 and an increased number of out-of-service days for regulatory drydock and vessel upgrades for certain vessels in our Shelf Contracting segment.

Oil and Gas revenues increased 36% during 2007 as compared to the prior year. The increase was primarily due to increases in oil and natural gas production. The production volume increase of 33% over 2006 was mainly attributable to properties acquired in connection with the Remington acquisition, which closed on July 1, 2006.

Gross Profit. The Contracting Services gross profit increase was primarily attributable to improved contract pricing for the pipelay, well operations and ROV divisions. The gross profit increase within Shelf Contracting was primarily attributable to increased gross profit derived from the initial deployment of certain assets we acquired subsequent to the first quarter 2006, offset by increased out-of-service days referred to above, lower vessel utilization as a result of seasonal weather in the fourth quarter 2007, and increased depreciation and deferred drydock amortization.

The Oil and Gas gross profit decrease in 2007 as compared to 2006 was primarily due to the following factors:

- impairment expenses totaling $64.1 million, which primarily reflected $59.4 million associated with property impairments related to downward reserve revisions and weak end of life well performance in some of our domestic properties and $9.6 million of increased future abandonment costs related to properties damaged by Katrina and Rita partially offset by estimated insurance recoveries of $4.9 million;

- an increase of $91.0 million in depletion expense in 2007 because of higher overall production based on a full year of activity from the Remington acquisition as compared to only half a year of impact in 2006 including approximately $12.5 million of increased fourth quarter 2007 depletion due to certain producing properties experiencing significant proved reserve declines;

- approximately $25.1 million of plug and abandonment overruns related to properties damaged by the hurricanes, partially offset by insurance recoveries of $4.0 million;

- approximately $9.9 million of impairment expense related to our unproved properties primarily due to management's assessment that exploration activities for certain properties will not commence prior to the respective lease expiration dates;

- the gross profit decrease was partially offset by lower dry hole exploration expense in 2007 of $10.3 million, of which $5.9 million was related to our South Marsh Island 123 #1 well, as compared to $38.3 million dry hole expense in 2006 related to the Tulane prospect and two deep shelf wells commenced by Remington prior to the acquisition.

Gain on Sale of Assets, Net. Gain on sale of assets, net, increased by $47.6 million during 2007 as compared to 2006. On September 30, 2007, we sold a 30% working interest in the Phoenix oilfield (Green Canyon Blocks 236/237), the Boris oilfield (Green Canyon Block 282) and the Little Burn oilfield (Green Canyon Block 238) to Sojitz for a cash payment of $51.2 million and recognized a gain of $40.4 million in 2007. We also recognized the following gains in 2007:

- $2.4 million related to the sale of a mobile offshore production unit;

- $1.6 million related to the sale or 50% interest in Camelot; and

- $3.9 million related to the sale of assets owned by CDI.

Selling and Administrative Expenses. Selling and administrative expenses of $151.4 million in 2007 were $31.8 million higher than the $119.6 million incurred in 2006. The increase was due primarily to higher overhead to support our growth and increased incentive compensation accruals. Further, in June 2007, CDI recorded a $2.0 million charge for a cash settlement with the Department of Justice. Selling and administrative expenses as a percent of revenues were approximately 9% for both 2007 and 2006.

Equity in Earnings of Investments, Net of Impairment Charge. Equity in earnings of investments increased by $1.6 million during 2007 as compared to 2006. Equity in earnings related to our 20% investment in Independence Hub increased $10.5 million as we reached mechanical completion in March 2007 and began receiving demand fees and tariffs as production began in the third quarter. In addition, equity in earnings of our 50% investment in Deepwater Gateway increased by $2.2 million in 2007 as compared to 2006 due to higher throughput at the Marco Polo TLP. These increases were offset by second quarter 2007 equity losses from CDI's 40% investment in OTSL and a related non-cash asset impairment charge together totaling $11.8 million.

Gain on Subsidiary Equity Transaction. We recognized a non cash pre-tax gain of $151.7 million ($98.6 million net of taxes of $53.1 million) in 2007 as our share of CDI's underlying equity increased as a result of CDI's issuance of 20.3 million shares of its common stock to former Horizon stockholders in connection with CDI's acquisition of Horizon, which reduced our ownership in CDI to 58.5%. The non-cash gain is derived from the difference in the value of our investment in CDI immediately before and after the acquisition. In 2006, CDI received net proceeds of $264.4 million from the initial public offering of 22.2 million shares of its common stock. Together with CDI's drawdown of its revolving credit facility, CDI paid pre-tax dividends of $464.4 million to us in December 2006. As a result of these transactions, we recorded a pre-tax gain of $223.1 million ($96.5 million net of taxes of $126.6 million) in 2006.

Net Interest Expense and Other. We reported net interest and other expense of $59.4 million in 2007 as compared to $34.6 million in the prior year. Gross interest expense of $100.4 million during 2007 was higher than the $51.9 million incurred in 2006 as a result of our Term Loan and Revolving Loans, which closed in July 2006, and CDI's revolving credit facility, which closed in December 2006. Offsetting the increase in interest expense was $31.8 million of capitalized interest and $9.5 million of interest income in 2007, compared with $10.6 million of capitalized interest and $6.3 million of interest income in 2006.

Provision for Income Taxes. Income taxes decreased to $174.9 million in 2007 compared to $257.2 million in 2006. This variance includes a $126.6 million decrease of the income tax expense related to the CDI dividends paid to us in 2006, which was partially offset by increased profitability in 2007. The effective tax rate of 33.3% for 2007 was lower than the 42.5% effective tax rate for 2006 due primarily to the CDI dividends of $464.4 million received in December 2006.

Liquidity and Capital Resources

Overview

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

	2008	2007
Net working capital	$ 277,509	$ 48,290
Long-term debt(1)	$1,968,502	$1,725,541

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

The carrying amount of our debt, including current maturities as of December 31, 2008 and 2007 follow (amount in thousands):

	2008	2007
Term Loan (matures July 2013)	$ 419,093	$ 423,418
Revolving Credit Facility (matures July 2011)	349,500	18,000
Cal Dive Term Loan (matures December 2012)	315,000	375,000
Convertible Senior Notes (matures March 2025)	300,000	300,000
Senior Unsecured Notes (matures January 2016)	550,000	550,000
MARAD Debt (matures August 2027)	123,449	127,463
Loan Notes(1)	5,000	6,506
Total	$ 2,062,042	$ 1,800,387

(1) Assumed to be current, represents the $5 million loan provided by Kommandor RØMØ to Kommandor LLC (Note 10).

	Year Ended December 31,		
	2008	2007	2006
Net cash provided by (used in):			
Operating activities	$ 437,719	$ 416,326	$ 514,036
Investing activities	$ (557,974)	$ (739,654)	$ (1,379,930)
Financing activities	$ 256,216	$ 206,445	$ 978,260

Our current requirements for cash primarily reflect the need to fund capital expenditures to allow the growth of our current lines of business and to service our existing debt. We also intend to repay debt with any additional free cash flow from operations and/or cash received from any dispositions of our non core business assets. Historically, we have funded our capital program, including acquisitions, with cash flow from operations, borrowings under credit facilities and use of project financing along with other debt and equity alternatives.

We are closely monitoring the relatively recent and ongoing volatility and uncertainty in the financial markets and have intensified our internal focus on liquidity, planned spending and access to capital. Externally we have also been engaged with our clients and the lending institutions on our various debt facilities as our customers and lenders are going through similar exercises. While we believe at this stage it is premature to accurately predict to what extent these current events may affect our overall activity levels in 2009 and beyond, we do expect a significant decrease in activity as compared to 2008. To date, we have received no communication from our lenders that they are unable or unwilling to fund any commitments under our Revolving Credit Facility. Additionally, all participating banks party to our Revolving Credit Facilities have honored their commitments. We also have a reasonable basis for estimating our future cash flow supported by our contracting services backlog and the significant hedged portion of our estimated 2009 oil and gas production. We believe that internally generated cash flow and available borrowing capacity under our existing Revolving Credit Facility will be sufficient to fund our operations for 2009.

A continuing period of weak economic activity will 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 is affected by the current 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. We cannot assure you that we would have access to the credit markets as needed to replace our existing debt and we could incur increased costs associated with any available replacement financing.

Some of the significant financings and corresponding uses were as follows:

- In January 2009, CDI borrowed $100 million under our revolving credit facility to repurchase 13.6 million shares of its common stock from us for $6.34 per share. The remaining funds will be used to fund CDI working capital requirements and other general corporate purposes. As of February 20, 2009, CDI had $415 million of debt, $67.3 million of cash on hand and $186.7 million of available under our credit facility.

- In July 2007, we purchased the remaining 42% of WOSEA for $10.1 million. We now own 100% of this company (Note 6).

- In December 2007, we issued $550 million of 9.5% Senior Unsecured Notes due 2016 (“Senior Unsecured Notes”). Proceeds from the offering were used to repay outstanding indebtedness under our senior secured credit facilities. See Note 11 for additional information on the terms of the Senior Unsecured Notes.

- Also in December 2007, CDI replaced its five-year $250 million revolving credit facility with a secured credit facility consisting of a $375 million term loan and a $300 million revolving credit facility. Proceeds from the CDI term loan were used to fund the cash portion of the Horizon acquisition. CDI expects to use the remaining capacity under the revolving credit facility for its working capital and other general corporate purposes. We do not have access to the unused portion of CDI’s revolving credit facility. See Note for additional information regarding our long term debt.

- In July 2006, we borrowed $835 million in a term loan (“Term Loan”) and entered into a new $300 million revolving credit facility (Note 11). The proceeds of the Term Loan were used to fund the cash portion of the acquisition of Remington. We also issued approximately 13.0 million shares of our common stock to the Remington shareholders.

- In December 2006, we completed an IPO of our Shelf Contracting business segment (Cal Dive International, Inc.), selling 26.5% of that company and receiving pre-tax net proceeds of $264.4 million. We may sell additional shares of CDI common stock in the future. Proceeds from the offering were used for general corporate purposes, including the repayment of $71.0 million of borrowing under our Revolving Credit Facility (Note 3).

- In connection with the IPO, CDI Vessel Holdings LLC (“CDI Vessel”), a subsidiary of CDI, entered into a secured credit facility for up to $250 million in revolving loans under a five-year revolving credit facility. During December 2006, CDI Vessel borrowed $201 million under the revolving credit facility and distributed $200 million of those proceeds to us as a dividend. This revolving loan was replaced in December 2007 by the $300 million revolving credit facility described above.

- In October 2006, we initially invested $15 million for a 50% interest in Kommandor LLC, a Delaware limited liability company, to convert a ferry vessel into a dynamically-positioned minimal floating production system. We have consolidated the results of Kommandor LLC in accordance with FASB Interpretation No. 46(R), Consolidation of Variable Interest Entities (“FIN 46”). For additional information, see Note 10. We have named the vessel Helix Producer I.

- Also in October 2006, we acquired the original 58% interest in WOSEA for total consideration of approximately $12.7 million (including $180,000 of transaction costs), with approximately $9.1 million paid to existing shareholders and $3.4 million for subscription of new WOSEA shares (see Note 6 for a detailed discussion of WOSEA).

In 2006, our Board of Directors also authorized us to discretionarily purchase up to $50 million of our common stock in the open market. In October and November 2006, we purchased approximately 1.7 million shares under this program for a weighted average price of $29.86 per share, or $50.0 million.

In accordance with our Senior Credit Facilities, Senior Unsecured Notes, the Convertible Senior Notes, the MARAD debt and Cal Dive's credit facilities, we are required to comply with certain covenants and restrictions, including certain financial ratios such as collateral coverage, interest coverage, consolidated leverage, the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of December 31, 2008, we were in compliance with these covenants. The Senior Credit Facilities and Senior

Unsecured Notes also contain provisions that limit our ability to incur certain types of additional indebtedness. These provisions effectively prohibit us from incurring any additional secured indebtedness or indebtedness guaranteed by the Company. The Senior Credit Facilities do permit us to incur certain unsecured indebtedness, and also provide for our subsidiaries to incur project financing indebtedness (such as our MARAD loans) secured by the underlying asset, provided that the indebtedness is not guaranteed by us. Upon the occurrence of certain dispositions or the issuance or incurrence of certain types of indebtedness, we may be required to prepay a portion of the Term Loan equal to the amount of proceeds received from such occurrences. Such prepayments will be applied first to the Term Loan, and any excess will then be applied to the Revolving Loans.

As of December 31, 2008, we had $44.4 million ($59.4 million as of February 27, 2009) of available borrowing capacity under our Revolving Credit Facility, and CDI had $292.5 million of available borrowing capacity under its revolving credit facility. See Note 11 for additional information related to our long-term debts, including our obligations under capital commitments.

Working Capital

Cash flows from operating activities increased $21.4 million in 2008 as compared to 2007 primarily reflecting significantly lower income taxes paid and increased gross profit from Contracting Services and Shelf Contracting businesses. These increases were partially offset by lower operating results for our Oil and Gas business reflecting the effects of Hurricanes Gustav and Ike had on its production during the third and fourth quarters of 2008 as well as our increased funding of our working capital requirements.

Cash flow from operating activities decreased $97.7 million in 2007 as compared to 2006 primarily due to negative working capital changes in 2007. Compared to 2006, increased expenditures in other noncurrent assets, net, consisted of an additional $21.6 million in drydock expenses (net of amortization), $8.8 million for an equipment deposit and $14.6 million related to a non-current contract receivable for retainage. Working capital, net of cash, decreased approximately $145.5 million in 2007 when compared to 2006. Cash from operating activities was negatively impacted by higher income taxes paid in 2007 versus 2006 of approximately $146.9 million, of which $126.6 million was related to CDI's initial public offering. These decreases were partially offset by increase in profitability, excluding the impact of non-cash related items, in 2007 as compared to 2006.

Investing Activities

Capital expenditures have consisted principally of the purchase or construction of DP vessels, acquisition of select businesses, improvements to existing vessels, acquisition of oil and gas properties and investments in our Production Facilities. Significant sources (uses) of cash associated with investing activities for the years ended December 31, 2008, 2008 and 2007 were as follows (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Capital expenditures:			
Contracting services	$ (258,660)	$ (287,577)	$ (130,938)
Shelf contracting	(83,108)	(30,301)	(38,086)
Oil and gas	(404,308)	(519,632)	(282,318)
Production facilities	(109,454)	(106,086)	(17,749)
Acquisition of businesses, net of cash acquired:			
Remington Oil and Gas Corporation(1)			(772,244)
Horizon Offshore Inc. (2)		(137,431)	
Acergy US Inc. (3)			(78,174)

Fraser Diving International Ltd. (3)			(21,954)
WOSEA(4)		(10,067)	(10,571)
Kommandor LLC			(5,000)
(Purchases) sale of short-term investments		285,395	(285,395)
Investments in production facilities	(846)	(17,459)	(27,578)
Distributions from equity investments, net(4)	11,586	6,679	
Increase in restricted cash	(614)	(1,112)	(6,666)
Proceeds from insurance recoveries	13,200		
Proceeds from sale of subsidiary stock			264,401
Proceeds from sale of properties (5)	274,230	78,073	32,342
Other, net		(136)	
Cash used in investing activities	$ (557,974)	$ (739,654)	$ (1,379,930)

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(1) For additional information related to the Remington acquisition, see Note 4.

(2) For additional information related to the Horizon acquisition, see Note 5.

(3) For additional information related to these acquisitions, see Note 6.

(4) Distributions from equity investments is net of undistributed equity earnings from our investments. Gross distributions from our equity investments are detailed in Note 9.

(5) For additional information related to sales of properties, see Note 7.

Short-term Investments

As of December 31, 2006, we held approximately $285.4 million in municipal auction rate securities. We did not hold these types of securities at December 31, 2008 or 2007. These instruments were long-term variable rate bonds tied to short-term interest rates reset through a “Dutch Auction” process which occured every 7 to 35 days and were classified as available-for-sale securities.

Restricted Cash

As of December 31, 2008 we had $35.4 million of restricted cash, included in other assets, net, in the accompanying consolidated balance sheet, all of which related to the escrow funds for decommissioning liabilities associated with the South Marsh Island Block 130 (“SMI 130”) acquisition in 2002. Under the purchase agreement for this property, we are obligated to escrow 50% of production up to the first $20 million and 37.5% of production on the remaining balance up to $33 million in total . We had fully escrowed the requirement as of December 31, 2008. We may use the restricted cash for decommissioning the related field.

Outlook

We anticipate capital expenditures in 2009 will range from $350 million to $400 million (of which $78 million is related to CDI). The estimates for these capital expenditures may increase or decrease based on various economic factors. However, we may reduce the level of our planned capital expenditures given a prolonged economic downturn and inability to execute sales transactions related to our non core business assets. We believe internally generated cash flow, cash from future sales of our non core business assets, and borrowings under our existing credit facilities will provide the capital necessary to fund our 2009 initiatives.

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual cash obligations as of December 31, 2008 and the scheduled years in which the obligation are contractually due (in thousands):

	Total (1)	Less Than 1 year	1-3 Years	3-5 Years	More Than 5 Years
Convertible Senior Notes(2)	$ 300,000	$	$	$	$ 300,000

Senior Unsecured Notes	550,000				550,000
Term Loan	419,093	4,326	8,652	406,115	
Revolving Loans	349,500		349,500		
MARAD debt	123,449	4,214	9,069	9,997	100,169
CDI Term Loan	315,000	80,000	160,000	75,000	
Loan note	5,000	5,000			
Interest related to long-term debt(3)	693,364	101,093	178,169	158,881	255,221
Preferred stock dividends(4)	1,000	1,000			
Drilling and development costs	106,300	16,800	89,500		
Property and equipment(5)	47,941	47,941			
Operating leases(6)	191,623	84,893	75,708	21,644	9,378
Total cash obligations	$3,102,270	$ 345,267	$ 870,598	$ 671,637	$1,214,768

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(1) Excludes unsecured letters of credit outstanding at December 31, 2008 totaling $33.7 million. These letters of credit primarily guarantee various contract bidding, insurance activities and shipyard commitments.

(2) Maturity 2025 (Notes can be redeemed by us or we may be required to purchase beginning in December 2012). Can be converted prior to stated maturity if closing sale price of Helix's common stock for at least 20 days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter exceeds 120% of the closing price on that 30th trading day (i.e. $38.56 per share) and under certain triggering events as specified in the indenture governing the Convertible Senior Notes. To the extent we do not have alternative long-term financing secured to cover the conversion, the Convertible Senior Notes would be classified as a current liability in the accompanying balance sheet. As of December 31, 2008, the conversion trigger was not met.

(3) Includes total interest obligations of $26.4 million related to CDI's long-term debt.

(4) Amount represents dividend payment for 2009 only. Dividends are paid annually until such time the holder elects to convert or redeem the stock. The holder redeemed $30 million of our convertible preferred stock shares into 5.9 million shares of our common stock in January 2009 (Note 13). Our first-quarter 2009 results will include a corresponding noncash dividend of $29.3 million to reflect the redemption of the incremental shares issued to the holder above the shares underlying the redemption feature. This dividend will reduce the net income available to our common shareholders for the period.

(5) Costs incurred as of December 31, 2008 and additional property and equipment commitments (excluding capitalized interest) at December 31, 2008 consisted of the following (in thousands):

	Costs Incurred	Costs Committed	Total Project Cost
Caesar conversion	$ 158,937	$ 11,832	$ 210,000—230,000
Well Enhancer construction	149,691	31,165	200,000—220,000
Helix Producer I conversion(a)	210,107	4,944	345,000—365,000
Total	$ 518,735	$ 47,941	$ 755,000—815,000

(a) Represents 100% of the vessel conversion cost, of which we expect our portion to range between $301 million and $321 million.

(6) Operating leases included facility leases and vessel charter leases. Vessel charter lease commitments at December 31, 2008 were approximately $153.9 million. Operating leases include $21.6 million related to CDI.

Contingencies

In December 2005 and in May 2006, our Oil and Gas segment received notice from the MMS that the price threshold was exceeded for 2004 oil and gas production and for 2003 gas production, respectively, and that royalties are due on such production notwithstanding the provisions of the DWRRA. In addition, in September 2008, we received notice from the MMS that price thresholds were exceeded for 2007, 2006 and 2005 oil and gas production. The total reserved amount at December 31, 2008 was approximately $69.7 million and was included in Other Long Term

Liabilities in the accompanying consolidated balance sheet included herein. On January 12, 2009, the United States Court of Appeals for the Fifth Circuit affirmed the decision of the district court in favor of Kerr-McGee, holding that the DWRRA unambiguously provides that royalty suspensions up to certain production volumes established by Congress apply to leases that qualify under the DWRRA. As a result of this ruling, we believe that any future payment of these contractual royalties is not probable. Accordingly, in the first quarter of 2009 our operating results will include a $69.7 million gain from the reversal of these previously reserves amounts associated with the potential payment of the disputed royalties. See Item 3. Legal Proceedings and Note 18 for a detailed discussion of this contingency.

Convertible Preferred Stock

In January 2003, we completed the private placement of $25 million of a newly designated class of cumulative convertible stock (Series A-1 Cumulative Convertible Stock, par value $0.01 per share) convertible into 1,666,668 shares or our common stock at $15 per share. The preferred stock was issued to a private investment firm, Fletcher International, Ltd.("Fletcher"). Subsequently on June 2004, Fletcher exercised an existing right to purchase an additional $30 million of cumulative convertible preferred stock (Series A-2 Cumulative Convertible Preferred Stock, par value $0.01 per share) convertible into 1,964,058 shares of our common stock at $15.27

per share. Pursuant to the agreement governing the preferred stock (the "Fletcher Agreement"), Fletcher was entitled to convert its investment in the preferred shares at any time, and to redeem its investment in the preferred shares at any time after December 31, 2004. In January 2009, Fletcher issued a redemption notice with respect to all of the Series A-2 Cumulative Convertible Preferred Stock, and, pursuant to such redemption, we issued and delivered 5,938,776 shares of our common stock to Fletcher. We will reduce net income applicable to common shareholders by an approximate $29.3 million non-cash dividend that will be reflected in our first quarter of 2009 results. This non-cash dividend reflects the value associated with the additional 3,974,718 shares delivered over the original 1,964,058 shares that were contractually required to be issued upon a conversion.

The Fletcher Agreement provides that if the volume weighted average price of our common stock on any date is less than a certain minimum price ($2.767), then our right to pay dividends in our common stock is extinguished, and we must deliver a notice to Fletcher that either (1) the conversion price will be reset to such minimum price (in which case Fletcher shall have no further right to cause the redemption of the preferred stock), or (2) in the event Fletcher exercises its redemption rights, we will satisfy our redemption obligations either in cash, or a combination of cash and common stock subject to a maximum number of shares (14,973,814) that can be delivered to the holder under the Fletcher Agreement. As a result of the redemption that occurred in January, the maximum number of shares available for redemption of the Series A-1 Cumulative Convertible Stock is 9,035,038. On February 25, 2009 the volume weighted average price of our common stock was below the minimum price, and on February 27, 2009 we provided notice to Fletcher that with respect to the Series A-1 Cumulative Convertible Preferred Stock the conversion price is reset to $2.767 as of that date and that Fletcher shall have no further rights to redeem the shares, and we have no further right to pay dividends in common stock. As a result of Fletcher's redemption in January 2009, and the reset of the conversion price, Fletcher would receive an aggregate of 9,035,038 shares in future conversion(s) into our common stock. In the event we elect to settle any future conversion in cash, Fletcher would receive cash in an amount approximately equal to the value of the shares it would receive upon a conversion, which could be substantially greater than the original face amount of the Series A-1 Cumulative Convertible Preferred Stock. Under the existing terms of our Senior Credit Facilities (Note 11) we are not permitted to deliver cash to the holder upon a conversion of the Convertible Preferred Stock.

Critical Accounting Estimates and Policies

Our results of operations and financial condition, as reflected in the accompanying financial statements and related footnotes, are prepared in conformity with accounting principles generally accepted in the United States. As such, we are required to make certain estimates, judgments and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. We base our estimates on historical experience, available information and various other assumptions we believe to be reasonable under the circumstances. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. We believe the most critical accounting policies in this regard are those described below. While these issues require us to make judgments that are somewhat subjective, they are generally based on a significant amount of historical data and current market data. For a detailed discussion on the application of our accounting policies, see Item 8. Financial Statements and Supplementary Data "— Notes to Consolidated Financial Statements — Note 2."

Revenue Recognition

Contracting Services Revenues

Revenues from Contracting Services and Shelf Contracting are derived from contracts that traditionally have been of relatively short duration; however, beginning in 2007, contract durations started to become longer-term. These contracts contain either lump-sum turnkey provisions or provisions for specific time, material and equipment charges, which are billed in accordance with the terms of such contracts. We recognize revenue as it is earned at estimated collectible amounts. Further, we record revenue net of taxes collected from customers and remitted to governmental authorities.

Unbilled revenue represents revenue attributable to work completed prior to period end that has not yet been invoiced. All amounts included in unbilled revenue at December 31, 2008 and 2007 are expected to be billed and collected within one year.

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

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

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

Under the percentage-of-completion method, we recognize estimated contract revenue based on costs incurred to date as a percentage of total estimated costs. Changes in the expected cost of materials and labor, productivity, scheduling and other factors affect the total estimated costs. Additionally, external factors, including weather and other factors outside of our control, may also affect the progress and estimated cost of a project’s completion and, therefore, the timing of income and revenue recognition. We routinely review estimates related to our contracts and reflect revisions to profitability in earnings on a current basis. If a current estimate of total contract cost indicates an ultimate loss on a contract, we recognize the projected loss in full when it is first determined. At December 31, 2008, we had two contracts that were deemed to be in loss status and we recorded an aggregate $9.8 million charge to cost of sales to estimate the expected loss to completion of the respective contracts (Note 2). We recognize additional contract revenue related to claims when the claim is probable and legally enforceable.

Oil and Gas Revenues

We record revenues from the sales of crude oil and natural gas when delivery to the customer has occurred, prices are fixed and determinable, collection is reasonably assured and title has transferred. This occurs when production has been delivered to a pipeline or a barge lifting has occurred. We may have an interest with other producers in certain properties. In this case, we use the entitlements method to account for sales of production. Under the entitlements method, we may receive more or less than our entitled share of production. If we receive more than our entitled share of production, the imbalance is treated as a liability. If we receive less than our entitled share, the imbalance is recorded as an asset. As of December 31, 2008, the net imbalance was a $1.7 million asset and was included in Other Current Assets ($7.5 million) and Accrued Liabilities ($5.8 million) in the accompanying consolidated balance sheet.

Purchase Price Allocation

In connection with a purchase business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Deferred taxes must be recorded for any differences between the assigned values and tax bases of assets and liabilities. Any excess of purchase price over amounts assigned to assets and liabilities is recorded as goodwill. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the value attributed to assets acquired and liabilities assumed.

In December 2007, CDI completed the acquisition of Horizon. This acquisition was accounted for as a business combination. The allocation of the purchase price was finalized during 2008 based upon valuations using estimates and assumptions that were reviewed and approved by CDI management.

In July 2006, we acquired the assets and assumed the liabilities of Remington in a transaction accounted for as a business combination. In estimating the fair values of Remington's assets and liabilities, we made various assumptions. The most significant assumptions related to the estimated fair values assigned to proved and unproved crude oil and natural gas properties. To estimate the fair values of these properties, we prepared estimates of crude oil and natural gas reserves. We estimated future prices to apply to the estimated reserve quantities acquired, and estimated future operating and development costs, to arrive at estimates of future net revenues. For estimated proved reserves, the future net revenues were discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the merger. The market-based weighted average cost of capital rate was subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved reserves, the estimated probable and possible reserves were reduced by additional risk-weighting factors.

Estimated deferred taxes were based on available information concerning the tax basis of Remington's assets and liabilities and loss carryforwards at the merger date. The allocation of purchase price for Remington was finalized in 2007.

While the estimates of fair value for the assets acquired and liabilities assumed have no effect on our cash flows, they can have an effect on the future results of operations. Generally, higher fair values assigned to crude oil and natural gas properties result in higher future depreciation, depletion and amortization expense, which results in a decrease in future net earnings. Also, a higher fair value assigned to crude oil and natural gas properties, based on higher future estimates of crude oil and natural gas prices, could increase the likelihood of an impairment in the event of lower commodity prices or higher operating costs than those originally used to determine fair value. An impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded.

In 2006, we also completed the acquisition of Acergy, Fraser and 58% of Seatrac. These acquisitions were accounted for as business combinations as well. We finalized the purchase price allocation for Acergy and Fraser in the second quarter of 2006 and 2007, respectively. In July 2007, we purchased the remaining 42% of Seatrac. The allocation of purchase price for Seatrac was finalized in 2008.

We complete our valuation of assets and liabilities (including deferred taxes) for the purpose of allocation of the total purchase price amount to assets acquired and liabilities assumed during the twelve-month period following the acquisition date.

For more information regarding the allocation of purchase price associated with our acquisition see Notes 4,5 and 6.

Goodwill and Other Intangible Assets

Under Statement of Financial Accounting Standard No. 142, "Goodwill and Other Intangible Assets" ("SFAS No. 142"), we are required to perform an annual impairment analysis of goodwill and intangible assets. We elected November 1 to be the annual impairment assessment date for goodwill and other intangible assets. However, we could be required to evaluate the recoverability of goodwill and other intangible assets prior to the required annual assessment date if we experience disruption to the business, unexpected significant declines in operating results, divestiture of a significant component of the business emergence of unanticipated competition, loss of key personnel or a sustained declined in market capitalization. SFAS No. 142 also requires testing of goodwill impairment to be at a reporting unit level and defines the reporting unit as an operating segment, as that term is used in SFAS No. 131, or one level below the operating segment (referred to as a "component"), depending on whether certain criteria are met. We have six reporting units with goodwill and our impairment analysis was conducted at this level.

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

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

We use both the income approach and market approach to estimate the fair value of our reporting units under the first step. Under the income approach, a discounted cash flow analysis is performed requiring us to make various judgmental assumptions about future revenue, operating margins, growth rates and discount rates. These judgmental assumptions are based on our budgets, long-term business plans, reserve reports, economic projections, anticipated future cash flows and market place data. Under the market approach, the fair value of each reporting unit is calculated by applying an average peer total invested capital EBITDA (defined as earnings before interest, income taxes and depreciation and amortization) multiple to the 2009 budgeted EBITDA for each reporting unit. Judgment is required when selecting peer companies that operate in the same or similar lines of business and are potentially subject to the same corresponding economic risks.

Based on the first step of the 2008 goodwill impairment analysis, the carrying amount of two of our reporting units exceeded its fair value as calculated under the first step, which required us to perform the second step of the impairment test. In the second step, the fair value of tangible and certain intangible assets was generally estimated using discounted cash flow analysis. The fair value of intangibles with indefinite lives, such as trademarks, was calculated using a royalty rate method. Based on our 2008 goodwill and indefinite lived intangible impairment analysis, we recorded a $704.3 million and $10.7 million charge to impairment expense in the fourth quarter of 2008 within our Oil and Gas and Contracting Services segments, respectively. These impairment charges were recorded as a component of operating loss in the accompanying consolidated statements of operations. These impairment charges did not have any current effect and will not have any future effect on cash flow or our results of operations.

While we believe we have made reasonable estimates and assumptions to calculate the fair value of the reporting units and other intangible assets, it is possible a material change could occur. We have $366.2 million of goodwill remaining at December 31, 2008, including $292.5 million for CDI. If our actual results are not consistent with our estimates and assumptions used to calculate fair value, our results of operations may be materially impacted as further impairments may occur. Unless there is a dramatic improvement in prevailing economic conditions, we will be required to again assess the fair value of our remaining goodwill and other intangible assets at March 31, 2009.

Income Taxes

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

We consider the undistributed earnings of our principal non-U.S. subsidiaries to be permanently reinvested. At December 31, 2008, our principal non-U.S. subsidiaries had accumulated earnings and profits of approximately $132.8 million. We have not provided deferred U.S. income tax on the accumulated earnings and profits. The deconsolidation of CDI's net income for tax return filing purposes after its initial public offering did not have a material impact on our consolidated results of operations; however, because of our inability to recover our tax basis in CDI tax free, a long term deferred tax liability is provided for any incremental increases to the book over tax basis.

It is our policy to provide for uncertain tax positions and the related interest and penalties based upon management's assessment of whether a tax benefit is more likely than not to be sustained upon examination by tax authorities. At December 31, 2008, we believe we have appropriately accounted for any unrecognized tax benefits. To the extent we prevail in matters for which a liability for an unrecognized tax benefit is established or are required to pay amounts in excess of the liability, our effective tax rate in a given financial statement period may be affected.

See Note 12 for discussion of net operating loss carry forwards, deferred income taxes and uncertain tax positions taken by the Company.

Accounting for Oil and Gas Properties

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

We follow the successful efforts method of accounting for our interests in oil and gas properties. Under the successful efforts method, the costs of successful wells and leases containing productive reserves are capitalized. Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized. Capitalized costs of producing oil and gas properties are depleted to operations by the unit-of-production method based on proved developed oil and gas reserves on a field-by-field basis as determined by our engineers. Leasehold costs for producing properties are depleted using the units-of-production method based on the amount of total estimated proved reserves on a field-by-field basis. Costs incurred relating to unsuccessful exploratory wells are expensed in the period the drilling is determined to be unsuccessful (see "— Exploratory Drilling Costs" below).

We evaluate the impairment of our proved oil and gas properties on a field-by-field basis at least annually or whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable. If an impairment is indicated, the cash flows are discounted at a rate approximate to our cost of capital and compared to the carrying value for determining the amount of the impairment loss to record. Estimated future cash flows are based on management's expectations for the future and include estimates of crude oil and natural gas reserves and future commodity prices, operating costs and future capital expenditures. Downward revisions in estimates of proved reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate a property impairment. We recorded property impairments totaling $215.7 million in 2008 ($192.6 million in the fourth quarter of 2008) and approximately $64.1 million of property impairments in 2007, primarily related to downward reserve revisions and weak end of life well performance in some of our domestic properties. There was no impairment of proved oil and gas properties in 2006.

We also periodically assess unproved properties for impairment based on exploration and drilling efforts to date on the individual prospects and lease expiration dates. Management's assessment of the results of exploration activities, availability of funds for future activities and the current and projected political climate in areas in which we operate also impact the amounts and timing of impairment provisions. We recorded a total of $8.9 million of exploration expense to write off certain unproved oil and gas properties reflecting management's assessment that exploration activities will not commence prior to the respective lease expiration dates, including a $8.0 million charge in the fourth quarter of 2008. During 2007, we recorded $9.9 million of exploration expense to impair certain unproved leasehold costs. There were no asset impairments recorded in 2006.

Exploratory Drilling Costs

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

At times, it may be determined that an exploratory well may have found hydrocarbons at the time drilling is completed, but it may not be possible to classify the reserves at that time. In this case, we may continue to capitalize the drilling costs as an uncompleted well beyond one year when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project, or the reserves are deemed to be proved. If reserves are not ultimately deemed proved or economically viable, the well is considered impaired and its costs, net of any salvage value, are charged to expense. At December 31, 2007, we had two wells that were deemed to be suspended wells under the criteria established by SFAS 19-1 "Accounting for Suspended Well Costs". Following the significant decrease in commodity prices in the second half of 2008 coupled with the December 2008 announcement of our intention to sell all or a part of our oil and gas business, we determined that further development of these wells was not probable. Accordingly, we recorded a total of $18.8 million to exploration expense to fully write off the capital costs associated with these two suspended wells.

Occasionally, we may choose to salvage a portion of an unsuccessful exploratory well in order to continue exploratory drilling in an effort to reach the target geological structure/formation. In such cases, we charge only the unusable portion of the well bore to dry hole expense, and we continue to capitalize the costs associated with the salvageable portion of the well bore and add the costs to the new exploratory well. In certain situations, the well bore may be carried for more than one year beyond the date drilling in the original well bore was suspended. This may be due to the need to obtain, and/or analyze the availability of equipment or crews or other activities necessary to pursue the targeted reserves or evaluate new or reprocessed seismic and geographic data. If, after we analyze the new information and conclude that we will not reuse the well bore or if the new exploratory well is determined to be unsuccessful after we complete drilling, we will charge the capitalized costs to dry hole expense. During the years ended December 31, 2008, 2007 and 2006, we incurred $27.7 million, $20.2 million and $38.3 million, respectively, of exploratory expenses (Note 7).

Estimated Proved Oil and Gas Reserves

The evaluation of our oil and gas reserves is critical to the management of our oil and gas operations. Decisions such as whether development of a property should proceed and what technical methods are available for development are based on an evaluation of reserves. These oil and gas reserve quantities are also used as the basis for calculating the unit-of-production rates for depreciation, depletion and amortization, evaluating impairment and estimating the life of our producing oil and gas properties in our decommissioning liabilities. Our proved reserves are classified as either proved developed or proved undeveloped. Proved developed reserves are those reserves which can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves include reserves expected to be recovered from new wells from undrilled proven reservoirs or from existing wells where a significant major expenditure is required for completion and production. We prepare all of our reserve information, and our independent petroleum engineers' audit, and the estimates of our oil and gas reserves presented in this report (U.S. reserves only) based on guidelines promulgated under generally accepted accounting principles in the United States. See detailed description of our use of the term "engineering audit" and our process of preparing reserve estimates in Item 2. Properties "— Summary of Natural Gas and Oil Reserve Data." Our estimated proved reserves in this Annual Report include only quantities that we expect to recover commercially using current prices, costs, existing regulatory practices and technology. While we are reasonably certain that the estimated proved reserves will be produced, the timing and ultimate recovery can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and changes in projections of long-term oil and gas prices. Revisions can include upward or downward changes in the previously estimated volumes of proved reserves for existing fields due to evaluation of (1) already available geologic, reservoir or production data or (2) new geologic or reservoir data obtained from wells. Revisions can also include changes associated with significant changes in development strategy, oil and gas prices, or production equipment/facility capacity.

Accounting for Decommissioning Liabilities

Our decommissioning liabilities consist of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations ("SFAS 143") requires oil and gas companies to reflect decommissioning liabilities on the face of the balance sheet at fair value on a discounted basis. Prior to the Remington acquisition, we have historically purchased producing offshore oil and gas properties that are in the later stages of production. In conjunction with acquiring these properties, we assume an obligation associated with decommissioning the property in accordance with regulations set by government agencies. The abandonment liability related to the acquisitions of these properties is determined through a series of management estimates.

Prior to an acquisition and as part of evaluating the economics of an acquisition, we will estimate the plug and abandonment liability. Our oil and gas operations personnel prepare detailed cost estimates to plug and abandon wells and remove necessary equipment in accordance with regulatory guidelines. We currently calculate the discounted value of the abandonment liability (based on an estimate of the year the abandonment will occur) in accordance with SFAS No. 143 and capitalize that portion as part of the basis acquired and record the related abandonment liability at fair value. The recognition of a decommissioning liability requires that management make numerous estimates, assumptions and judgments regarding factors such as the existence of a legal obligation for liability; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. Decommissioning liabilities were $225.8 million and $217.5 million at December 31, 2008 and 2007, respectively.

On an ongoing basis, our oil and gas operations personnel monitor the status of wells, and as fields deplete and no longer produce, our personnel will monitor the timing requirements set forth by the MMS for plugging and abandoning the wells and commence abandonment operations, when applicable. On an annual basis, management personnel reviews and updates the abandonment estimates and assumptions for changes, among other things, in market conditions, interest rates and historical experience. In 2008 and 2007, we incurred $16.0 million and $25.1 million of plug and abandonment overruns related to hurricanes Katrina and Rita, respectively, partially offset by insurance recoveries of $13.4 million and $4.0 million.

Derivative Instruments and Hedging Activities

Our price risk management activities involve the use of derivative financial instruments to hedge the impact of market price risk exposures primarily related to our oil and gas production, variable interest rate exposure and foreign currency exposure. To reduce the impact of these risks on earnings and increase the predictability of our cash flows, from time to time we have entered into certain derivative contracts, primarily collars and swaps, for a portion of our oil and gas production, interest rate swaps, and foreign currency forward contracts. Our oil and gas costless collars and swaps, interest rate swaps, and foreign currency forward exchange contracts are reflected in our balance sheet at fair value. Hedge accounting does not apply to our oil and gas forward sales contracts as these qualify for the normal purchase and sale scope exception under Statement of Financial Accounting Standard No. 133, Accounting for Derivative Instruments and Hedging Activities ("SFAS No. 133").

We engage primarily in cash flow hedges. Changes in the derivative fair values that are designated as cash flow hedges are deferred to the extent that they are effective and are recorded as a component of accumulated other comprehensive income (a component of shareholders' equity) until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings.

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

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

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

Property and Equipment

Property and equipment (excluding oil and gas properties and equipment), both owned and under capital leases, are recorded at cost. Depreciation is provided primarily on the straight-line method over the estimated useful lives of the assets (Note 2).

For long-lived assets to be held and used, excluding goodwill, we base our evaluation of recoverability on impairment indicators such as the nature of the assets, the future economic benefit of the assets, any historical or future profitability measurements and other external market conditions or factors that may be present. If such impairment indicators are present or other factors exist that indicate that the carrying amount of the asset may not be recoverable, we determine whether an impairment has occurred through the use of an undiscounted cash flows analysis of the asset at the lowest level for which identifiable cash flows exist. Our marine vessels are assessed on a vessel by vessel basis, while our ROVs are grouped and assessed by asset class. If an impairment has occurred, we recognize a loss for the difference between the carrying amount and the fair value of the asset. The fair value of the asset is measured using quoted market prices or, in the absence of quoted market prices, is based on management's estimate of discounted cash flows.

Assets are classified as held for sale when we have a formalized plan for disposal of certain assets and those assets meet the held for sale criteria. Assets held for sale are reviewed for potential loss on sale when the company commits to a plan to sell and thereafter while the asset is held for sale. Losses are measured as the difference between the fair value less costs to sell and the asset's carrying value. Estimates of anticipated sales prices are judgmental and subject to revisions in future periods, although initial estimates are typically based on sales prices for similar assets and other valuation data. We had no assets that met the criteria of being classified as assets held for sale at December 31, 2008.

Recertification Costs and Deferred Drydock Charges

Our Contracting Services and Shelf Contracting vessels are required by regulation to be recertified after certain periods of time. These recertification costs are incurred while the vessel is in drydock. In addition, routine repairs and maintenance are performed and, at times, major replacements and improvements are performed. We expense routine repairs and maintenance as they are incurred. We defer and amortize drydock and related recertification costs over the length of time for which we expect to receive benefits from the drydock and related recertification, which is generally 30 months. Vessels are typically available to earn revenue for the 30-month period between drydock and related recertification processes. A drydock and related recertification process typically lasts one to two months, a period during which the vessel is not available to earn revenue. Major replacements and improvements, which extend the vessel's economic useful life or functional operating capability, are capitalized and depreciated over the vessel's remaining economic useful life. Inherent in this process are estimates we make regarding the specific cost incurred and the period that the incurred cost will benefit.

As of December 31, 2008 and 2007, capitalized deferred drydock charges (Note 8) totaled $38.6 million and $48.0 million, respectively. During the years ended December 31, 2008, 2007 and 2006, drydock amortization expense was $26.0 million, $23.0 million and $12.0 million, respectively. We expect drydock amortization expense to increase in future periods due to increases in the number of vessels as a result of the acquisitions made in 2006 and 2007.

Equity Investments

We periodically review our investments in Deepwater Gateway and Independence Hub for impairment. Under the equity method of accounting, an impairment loss would be recorded whenever a decline in value of an equity investment below its carrying amount is determined to be other than temporary. In judging "other than temporary," we would consider the length of time and extent to which the fair value of the investment has been less than the carrying amount of the equity investment, the near-term and longer-term operating and financial prospects of the equity company and our longer-term intent of retaining the investment in the entity. During 2007, CDI determined that there was an other than temporary impairment in OTSL and the full value of CDI's investment in OTSL was impaired and CDI recognized equity losses of OTSL, inclusive of the impairment charge, of $10.8 million in 2007 (Note 9).

Worker's Compensation Claims

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

Recently Issued Accounting Principles

In September 2006, the FASB issued Statement No. 157, Fair Value Measurements ("SFAS No. 157"). SFAS No. 157 was originally effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. The FASB agreed to defer the effective date of SFAS No. 157 for all nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis. We adopted the provisions of SFAS No. 157 on January 1, 2008 for assets and liabilities not subject to the deferral and adopted this standard for all other assets and liabilities on January 1, 2009. The adoption of SFAS No. 157 had immaterial impact on our results of operations, financial condition and liquidity.

SFAS No. 157, among other things, defines fair value, establishes a consistent framework for measuring fair value and expands disclosure for each major asset and liability category measured at fair value on either a recurring or nonrecurring basis. SFAS No. 157 clarifies that fair value is an exit price, representing the amount that would be received to sell an asset, or paid to transfer a liability, in an orderly transaction between market participants. SFAS No. 157 establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value as follows:

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

Assets and liabilities measured at fair value are based on one or more of three valuation techniques noted in SFAS No. 157. The valuation techniques are as follows:

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

The following table provides additional information related to assets and liabilities measured at fair value on a recurring basis at December 31, 2008 (in thousands):

	Level 1	Level 2	Level 3	Total	Valuation Technique
Assets:					
Oil and gas swaps and collars	–	$ 22,307	–	$ 22,307	(c)
Liabilities:					
Foreign currency forwards	–	940	–	940	(c)
Interest rate swaps	–	7,967	–	7,967	(c)
Total	–	$ 8,907	–	$ 8,907	

In December 2007, the FASB issued Statement No. 141 (Revised), Business Combinations ("SFAS No. 141(R)"). SFAS No. 141 (R) requires the acquiring entity in a business combination to recognize all the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. It also requires that the costs incurred related to the acquisition be charged to expense as incurred, when previously these costs were capitalized as part of the acquisition cost of the assets or business. The provisions of SFAS No. 141(R) are effective for fiscal years beginning after December 15, 2008 and should be adopted prospectively. We adopted the provisions of SFAS No. 141(R) on January 1, 2009 and it had no impact on our results of operations, cash flows and financial condition.

In December 2007, the FASB issued Statement No. 160, Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB 51 ("SFAS No. 160"). SFAS No. 160 improves the relevance, comparability, and transparency of financial information provided to investors by requiring all entities to report noncontrolling (minority) interests in subsidiaries as equity in the consolidated financial statements. The provisions of SFAS No. 160 are effective for fiscal years beginning after December 15, 2008 and required to be adopted prospectively, except the following provisions must be accepted retrospectively:

1. Reclassifying noncontrolling interest from the "mezzanine" to equity, separate from the parents' shareholders' equity, in the statement of financial position; and
2. Recast consolidated net income to include net income attributable to both the controlling and noncontrolling interests. That is, retrospectively, the noncontrolling interests' share of a consolidated subsidiary's income should not be presented in the income statement as "minority interest."

Further, effective January 1, 2009, we have changed our accounting policy of recognizing a gain or loss upon any future direct sale or issuance of equity by our subsidiaries if the sales price differs from our carrying amount to be in accordance with SFAS No. 160, in which a gain or loss will only be recognized when loss of control of a consolidated subsidiary occurs. In January 2009, we sold approximately 13.6 million shares of CDI common stock to CDI for $86 million. This transaction constituted a single transaction and was not part of any planned set of transactions that would result in us having a noncontrolling interest in CDI and reduced our ownership in CDI to approximately 51%. Since we retained control of CDI immediately after the transaction, the approximate $2.9 million loss on this sale will be treated as a reduction of our equity in our consolidated balance sheet. Any future transactions would result in us losing control of CDI and accordingly the gain or loss on those transactions will flow through our earnings.

In March 2008, the FASB issued Statement No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133 ("SFAS No. 161"). SFAS 161 applies to all derivative instruments and related hedged items accounted for under SFAS No. 133. SFAS No. 161 asks entities to provide qualitative disclosures about the objectives and strategies for using derivatives, quantitative data about the fair value of and gains and losses on derivative contracts, and details of credit-risk-related contingent features in their hedged positions. The standard is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged, but not required. We adopted the provisions of SFAS No. 161 on January 1, 2009 and it had no impact on our results of operations, cash flows and financial condition.

In May 2008, the FASB issued FASB Staff Position ("FSP") APB 14-1, Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement) ("FSP APB 14-1"). The FSP would require the proceeds from the issuance of convertible debt instruments to be allocated between a liability component (issued at a discount) and an equity component. The resulting debt discount would be amortized over the period the convertible debt is expected to be outstanding as additional non-cash interest expense. The effective date of FSP APB 14-1 is for fiscal years beginning after December 15, 2008 and requires retrospective application to all periods reported (with the cumulative effect of the change reported in retained earnings as of the beginning of the first period presented). The FSP does not permit early application. This FSP changes the accounting treatment for our Convertible Senior Notes. FSP APB 14-1 will increase our non-cash interest expense for our past and future reporting periods. On January 1, 2009, we adopted the provisions of FSP APB 14-1. Had this new standard been effective for the years ended December 31, 2008 and 2007, the Company estimates interest expense would have increased by approximately $7.8 million and $7.4 million respectively. Diluted loss per share for the year ended December 31, 2008 would have increased by approximately $0.06 per share and diluted earnings per share for the year ended December 31, 2007 would have decreased by approximately $0.13 per share.

In June 2008, the FASB issued FSP Emerging Issues Task Force 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities ("FSP EITF 03-6-1"). This FSP would require unvested share-based payment awards containing non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) to be included in the computation of basic EPS according to the two-class method. The effective date of FSP EITF 03-6-1 is for fiscal years beginning after December 15, 2008 and requires all prior-period EPS data presented to be adjusted retrospectively (including interim financial statements, summaries of earnings, and selected financial data) to conform with the provisions of this FSP. FSP EITF 03-6-1 does not permit early application. This FSP changes our calculation of basic and diluted EPS and will lower previously reported basic and diluted EPS as weighted-average shares outstanding used in the EPS calculation will increase. Upon adoption on January 1, 2009 the changes resulting from this FSP on our EPS data are listed in the following table:

Earnings per share – Basic

For the Year Ended:	Reported	Pro Forma	Variance
2008	$ (6.99)	$ (6.91)	$ 0.08
2007	3.52	3.47	(0.05)
2006	4.07	4.03	(0.04)

Earnings per share – Diluted

For the Year Ended:	Reported	Pro Forma	Variance
2008	$(6.99)	$(6.91)	$0.08
2007	3.34	3.27	(0.07)
2006	3.87	3.81	(0.06)

Also in June 2008, the FASB issued Emerging Issues Task Force Issue No. 07-5, Determining Whether an Instrument (or Embedded Feature) is Indexed to an Entity's Own Stock ("EITF 07-5"). This issue addresses the determination of whether an instrument (or an embedded feature) is indexed to an entity's own stock, which is the first part of the scope exception in paragraph 11(a) of SFAS No. 133. If an instrument (or an embedded feature) that has the characteristics of a derivative instrument under paragraphs 6–9 of SFAS No. 133 is indexed to an entity's own stock, it is still necessary to evaluate whether it is classified in shareholders' equity (or would be classified in shareholders' equity if it were a freestanding instrument). This issue is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application by an entity that has previously adopted an alternative accounting policy is not permitted. While we do not believe the adoption of this statement will have a material effect on our financial statements, we continue to assess its potential impact on our financial statements.

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

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

Interest Rate Risk. As of December 31, 2008, including the effects of interest rate swaps, approximately 38% of our outstanding debt was based on floating rates. Changes based on the floating interest rates under our variable rate debt could result in an increase or decrease in our annual interest expense and related cash outlay. To reduce the impact of this market risk, we entered into various cash flow hedging interest rate swaps to stabilize cash flows relating to interest payments on $200 million of our Term Loan and CDI hedged $100 million of its term loan. Excluding the portion of our consolidated debt for which we have interest rate swaps in place, the interest rate applicable to our remaining variable rate debt may rise, increasing our interest expense. The impact of market risk is estimated using a hypothetical increase in interest rates by 100 basis points for our variable rate long-term debt that is not hedged. Based on this hypothetical assumption, we would have incurred an additional $6.7 million in interest expense for the year ended December 31, 2008.

Commodity Price Risk. We have utilized derivative financial instruments with respect to a portion of our 2008, 2007 and 2006 oil and gas production to achieve a more predictable cash flow. We do not enter into derivative or other financial instruments for trading purposes.

As of December 31, 2008, we have the following volumes under derivatives and forward sales contracts related to our oil and gas producing activities totaling 2,222 MBbl of oil and 30,489 Mmcf of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			(per barrel)
January 2009 — June 2009	Collar	50.25 MBbl	$75.00 — $89.95
January 2009 — March 2009	Swap	40 MBbl	$57.16
January 2009 — December 2009	Forward Sales	150 MBbl	$71.79

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price (per Mcf)
Natural Gas:			
January 2009 — December 2009	Collar	1,029 Mmcf	$7.00 — $7.90
January 2009 — March 2009	Swap	529 Mmcf	$6.69
January 2009 — December 2009	Forward Sales	1,379 Mmcf	$8.23

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

Foreign Currency Exchange Risk. Because we operate in various regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar (primarily with respect to WOUK, Helix RDS and WOSEA). The functional currency for WOUK and Helix RDS is the applicable local currency (British Pound). The functional currency for WOSEA is the applicable local currency (Australian Dollar). Although the revenues are denominated in the local currency, the effects of foreign currency fluctuations are partly mitigated because local expenses of such foreign operations also generally are denominated in the same currency.

Assets and liabilities of WOUK, Helix RDS and WOSEA are translated using the exchange rates in effect at the balance sheet date, resulting in translation adjustments that are reflected in accumulated other comprehensive income in the shareholders' equity section of our balance sheet. Approximately 8% of our assets are impacted by changes in foreign currencies in relation to the U.S. dollar at December 31, 2008. We recorded unrealized gains (losses) of $(71.1) million, $3.7 million and $17.6 million to accumulated other comprehensive income (loss) for the years ended December 31, 2008, 2007 and 2006, respectively. Deferred taxes have not been provided on foreign currency translation adjustments since we consider our undistributed earnings (when applicable) of our non-U.S. subsidiaries to be permanently reinvested.

We also have subsidiaries with operations in the United Kingdom, Asia Pacific, the Middle East, Southeast Asia, the Mediterranean, Australia and Latin America. These international subsidiaries conduct the majority of their operations in these regions in U.S. dollars which they consider the functional currency. When currencies other than the U.S. dollar are to be paid or received, the resulting transaction gain or loss is recognized in the statements of operations. These amounts for the year ended December 31, 2008 were $9.8 million loss. The amounts for the year ended December 31, 2007 and 2006 were not material to our results of operations or cash flows.

Our cash flows are subject to fluctuations resulting from changes in foreign currency exchange rates. Fluctuations in exchange rates are likely to impact our business and cash flow in the future. As a result, we entered into various foreign currency forward purchase contracts to stabilize expected cash outflows relating to certain shipyard contracts where the contractual payments are denominated in euros and expected cash outflows relating to certain vessel charters denominated in British pounds. The aggregate fair value of the foreign currency forwards as of December 31, 2008 and 2007 was a net asset (liability) of ($0.9) million and $1.4 million, respectively. For the year ended December 31, 2008 we recorded unrealized gains of approximately $0.1 million in accumulated other comprehensive income (loss), a component of shareholders' equity, all of which are expected to be reclassified into earnings within the next 12 months. For the year ended December 31, 2007, we recorded unrealized gains of approximately $1.1 million, net of tax expense of $0.5 million, in accumulated other comprehensive income. In 2008, we recorded approximately $0.8 million of unrealized losses, net of tax benefit of $0.4 million, as other expense as a result of the change in fair value of our foreign currency forwards that did not qualify for hedge accounting.

Item 8. Financial Statements and Supplementary Data.

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Management's Report on Internal Control Over Financial Reporting

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In making its assessment, management has utilized the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework. Based on this assessment, management has concluded that, as of December 31, 2008, the Company's internal control over financial reporting is effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

Ernst & Young LLP has issued an audit report on the Company's internal control over financial reporting as of December 31, 2008.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Helix Energy Solutions Group, Inc. and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Helix Energy Solutions Group, Inc. and subsidiaries at December 31, 2008 and 2007, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 12 to the consolidated financial statements, in 2007 the Company adopted FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Helix Energy Solutions Group, Inc.’s internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 2, 2009 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 2, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited Helix Energy Solutions Group, Inc.'s internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Helix Energy Solutions Group, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Helix Energy Solutions Group, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Helix Energy Solutions Group, Inc. and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2008 and our report dated March 2, 2009 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas

March 2, 2009

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2008		December 31, 2007
ASSETS			
Current assets:			
Cash and cash equivalents	$ 223,613		$ 89,555
Accounts receivable —			
Trade, net of allowance for uncollectible accounts of $5,905 and $2,874	433,738		447,502
Unbilled revenue	43,565		10,715
Costs in excess of billing	74,361		53,915
Other current assets	175,030		125,582
Total current assets	950,307		727,269
Property and equipment	4,745,426		4,088,561
Less — Accumulated depreciation	(1,325,836)		(843,873)
	3,419,590		3,244,688
Other assets:			
Equity investments	197,287		213,429
Goodwill, net	366,218		1,089,758
Other assets, net	136,936		177,209
	$ 5,070,338		$ 5,452,353
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$ 346,235		$ 382,767
Accrued liabilities	233,023		221,366
Current maturities of long-term debt	93,540		74,846
Total current liabilities	672,798		678,979
Long-term debt	1,968,502		1,725,541
Deferred income taxes	604,464		625,508
Decommissioning liabilities	194,665		193,650
Other long-term liabilities	81,637		63,183
Total liabilities	3,522,066		3,286,861
Minority interests	322,627		263,926
Convertible preferred stock	55,000		55,000
Commitments and contingencies			
Shareholders' equity:			
Common stock, no par, 240,000 shares authorized, 91,972 and 91,385 shares issued	768,835		755,758
Retained earnings	435,506		1,069,546
	(33,696)		21,262

Accumulated other comprehensive income (loss)				
Total shareholders' equity		1,170,645		1,846,566
	$	5,070,338	$	5,452,353

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

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2008	2007	2006
	(In thousands, except per share amounts)		
Net revenues:			
Contracting services	$ 1,602,496	$ 1,182,882	$ 937,317
Oil and gas	545,853	584,563	429,607
	2,148,349	1,767,445	1,366,924
Cost of sales:			
Contracting services	1,161,227	789,988	584,295
Oil and gas	357,853	372,904	224,106
Oil and gas property impairments	215,675	64,072	—
Exploration expense	32,926	26,725	43,115
	1,767,681	1,253,689	851,516
Gross profit	380,668	513,756	515,408
Goodwill and other indefinite-lived intangible impairments	714,988	—	—
Gain on sale of assets, net	73,471	50,368	2,817
Selling and administrative expenses	184,708	151,380	119,580
Income (loss) from operations	(445,557)	412,744	398,645
Equity in earnings of investments	31,971	19,698	18,130
Gain on subsidiary equity transaction	—	151,696	223,134
Net interest expense and other	81,412	59,444	34,634
Income (loss) before income taxes	(494,998)	524,694	605,275
Provision for income taxes	89,977	174,928	257,156
Minority interest	45,873	29,288	725
Net income (loss)	(630,848)	320,478	347,394
Preferred stock dividends	3,192	3,716	3,358
Net income (loss) applicable to common shareholders	$ (634,040)	$ 316,762	$ 344,036
Earnings (loss) per common share:			
Basic	$ (6.99)	$ 3.52	$ 4.07
Diluted	$ (6.99)	$ 3.34	$ 3.87
Weighted average common shares outstanding:			
Basic	90,650	90,086	84,613
Diluted	90,650	95,938	89,874

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

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common Stock Shares	Common Stock Amount	Retained Earnings	Unearned Compensation	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
			(In thousands)			
Balance, December 31, 2005	77,694	$ 229,796	$ 408,748	$ (7,515)	$ (1,729)	$ 629,300
Comprehensive income:						
Net income	—	—	347,394	—	—	347,394
Foreign currency translations adjustments	—	—	—	—	17,601	17,601
Unrealized gain on hedges, net	—	—	—	—	11,364	11,364
Comprehensive income						376,359
Convertible preferred stock dividends	—	—	(3,358)	—	—	(3,358)
Stock compensation expense	—	9,364	—	—	—	9,364
Adoption of SFAS 123R	—	(7,515)	—	7,515	—	—
Stock issuance	13,033	553,570	—	—	—	553,570
Stock repurchase	(1,682)	(50,266)	—	—	—	(50,266)
Activity in company stock plans, net	1,583	8,319	—	—	—	8,319
Excess tax benefit from stock- based compensation	—	2,660	—	—	—	2,660
Balance, December 31, 2006	90,628	745,928	752,784	—	27,236	1,525,948
Comprehensive income:						
Net income	—	—	320,478	—	—	320,478
Foreign currency translations adjustments	—	—	—	—	3,680	3,680
Unrealized loss on hedges, net	—	—	—	—	(9,654)	(9,654)
Comprehensive income						314,504
Convertible preferred stock dividends	—	—	(3,716)	—	—	(3,716)
Stock compensation expense	—	14,607	—	—	—	14,607
Stock repurchase	(282)	(9,904)	—	—	—	(9,904)
Activity in company stock plans, net	1,039	4,547	—	—	—	4,547
Excess tax benefit from stock- based compensation	—	580	—	—	—	580
Balance, December 31, 2007	91,385	755,758	1,069,546	—	21,262	1,846,566
Comprehensive income (loss):						
Net loss	—	—	(630,848)	—	—	(630,848)
Foreign currency translations adjustments	—	—	—	—	(71,134)	(71,134)

Unrealized loss on hedges, net	—	—	—	—	16,176	16,176
Comprehensive loss						(685,806)
Convertible preferred stock dividends	—	—	(3,192)	—	—	(3,192)
Other	—	(3,952)	—	—	—	(3,952)
Stock compensation expense	—	15,506	—	—	—	15,506
Stock repurchase	(110)	(3,925)	—	—	—	(3,925)
Activity in company stock plans, net	697	4,113	—	—	—	4,113
Excess tax benefit from stock- based compensation	—	1,335	—	—	—	1,335
Balance, December 31, 2008	91,972	$ 768,835	$ 435,506	$ —$	(33,696)	$ 1,170,645

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

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

	Year Ended December 31, 2008	2007	2006
		(In thousands)	
Cash flows from operating activities:			
Net income (loss)	$ (630,848)	$ 320,478	$ 347,394
Adjustments to reconcile net income (loss) to net cash provided by operating activities —			
Depreciation and amortization	335,910	331,919	193,647
Asset impairment charge	215,675	64,072	—
Goodwill and other indefinite lived intangible impairments	714,988	—	—
Exploratory drilling and related expenditure	27,703	20,187	38,335
Equity in earnings of investments, net of distributions	2,803	582	(2,366)
Equity in (earnings) losses of OTSL, inclusive of impairment charge	—	10,841	487
Amortization of deferred financing costs	5,207	6,505	2,277
Stock compensation expense	21,412	17,302	9,364
Deferred income taxes	(3,074)	126,959	57,235
Excess tax benefit from stock-based compensation	(1,335)	(580)	(2,660)
Hedge ineffectiveness	(1,669)	—	—
Gain on subsidiary equity transaction	—	(151,696)	(223,134)
Gain on sale of assets, net	(73,471)	(50,368)	(2,817)
Minority interest	45,873	29,288	725
Changes in operating assets and liabilities:			
Accounts receivable, net	(36,234)	(5,918)	(67,211)
Other current assets	(4,936)	(22,820)	9,969
Income tax payable	(13,573)	(155,903)	142,949
Accounts payable and accrued liabilities	(126,559)	(51,635)	39,551
Other noncurrent, net	(40,153)	(72,887)	(29,709)
Net cash provided by operating activities	437,719	416,326	514,036
Cash flows from investing activities:			
Capital expenditures	(855,530)	(943,596)	(469,091)
Acquisition of businesses, net of cash acquired	—	(147,498)	(887,943)
(Purchases) sale of short-term investments	—	285,395	(285,395)
Investments in equity investments	(846)	(17,459)	(27,578)
Distributions from equity investments, net	11,586	6,679	—
Increase in restricted cash	(614)	(1,112)	(6,666)
Proceeds from insurance	13,200	—	—
Proceeds from sale of subsidiary stock	—	—	264,401
Proceeds from sales of property	274,230	78,073	32,342
Other, net	—	(136)	—
Net cash used in investing activities	(557,974)	(739,654)	(1,379,930)
Cash flows from financing activities:			
Borrowings under Helix term loan	—	—	835,000
Repayment of Helix term loan	(4,326)	(405,408)	(2,100)
Borrowings on Helix revolver	1,021,500	472,800	209,800
Repayments on Helix revolver	(690,000)	(454,800)	(209,800)
Borrowings on senior unsecured notes	—	550,000	—

Repayment of MARAD borrowings	(4,014)	(3,823)	(3,641)
Borrowings on CDI revolver	61,100	31,500	201,000
Repayments on CDI revolver	(61,100)	(332,668)	—
Borrowings on CDI term loan	—	375,000	—
Repayments on CDI term loan	(60,000)	—	—
Borrowing under loan notes	—	5,000	5,000
Deferred financing costs	(1,796)	(17,165)	(11,839)
Capital lease payments	(1,505)	(2,519)	(2,827)
Preferred stock dividends paid	(3,192)	(3,716)	(3,613)
Repurchase of common stock	(3,925)	(9,904)	(50,266)
Excess tax benefit from stock-based compensation	1,335	580	2,660
Exercise of stock options, net	2,139	1,568	8,886
Net cash provided by financing activities	256,216	206,445	978,260
Effect of exchange rate changes on cash and cash equivalents	(1,903)	174	2,818
Net (decrease) increase in cash and cash equivalents	134,058	(116,709)	115,184
Cash and cash equivalents:			
Balance, beginning of year	89,555	206,264	91,080
Balance, end of year	$ 223,613	$ 89,555	$ 206,264

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

HELIX ENERGY SOLUTIONS GROUP, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 — Organization

Effective March 6, 2006, we changed our name from Cal Dive International, Inc. to Helix Energy Solutions Group, Inc. ("Helix" or the "Company"). Unless the context indicates otherwise, the terms "we," "us" and "our" in this report re collectively to Helix and its subsidiaries, including Cal Dive International, Inc. (collectively with its subsidiaries referred to as "Cal Dive" or "CDI"). 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 Contracting Services segment utilizes our vessels, offshore equipment and proprietary technologies to deliver services that may reduce finding and development costs and cover the complete lifecycle of an offshore oil and gas field. Our Contracting Services are located primarily in Gulf of Mexico, North Sea, Asia Pacific and Middle East regions. Our Oil and Gas segment engages in prospect generation, exploration, development and production activities. Our oil and gas operations are almost exclusively located in the Gulf of Mexico.

Contracting Services Operations

We seek to provide services and methodologies which we believe are critical to finding and developing offshore reservoirs and maximizing production economics, particularly from marginal fields. By "marginal", we mean reservoirs that are no longer wanted by major operators or are too small to be material to them. Our "life of field" services are segregated into five disciplines: construction, well operations, drilling, reservoir and well technology services, and production facilities. We have disaggregated our contracting services operations into three reportable segments in accordance with Financial Accounting Standards Board ("FASB") Statement No. 131 Disclosures about Segments of an Enterprise and Related Information ("SFAS No. 131"): Contracting Services; Shelf Contracting; and Production Facilities. Our Contracting Services business includes deepwater construction, well operations and reservoir and well technology services and drilling. Our Shelf Contracting business represents the assets of CDI, of which we owned 57.2% at December 31, 2008. In January 2009, our ownership of CDI was reduced to approximately 51% (Note 3). Our Production Facilities business includes our investments in Deepwater Gateway, L.L.C. ("Deepwater Gateway") and Independence Hub, LLC ("Independence Hub").

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 asset utilization of our contracting services business and to achieve incremental returns to our contracting services. Over the last 16 years 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. This has led to the assembly of services that allows us to create value at key points in the life of a reservoir from exploration through development, life of field management and operating through abandonment.

Economic Outlook

The recent economic downturn and weakness in the equity and credit capital markets has led to increased uncertainty regarding the outlook of the global economy. This uncertainty coupled with the probable decrease in the near-term global demand for oil and gas has resulted in commodity price declines over the second half of 2008, with significant declines occurring in the fourth quarter of 2008. Declines in oil and gas prices negatively impacts our operating results and cash flow. Our stock price significantly declined in the fourth quarter of 2008 ($24.28 per share at September 30, 2008 and $7.24 per share at December 31, 2008). The decline in our stock price and declines in the prices of oil and natural gas, were considered in association with our required annual impairment assessment of goodwill as of November 1, 2008, at which time we assessed the fair value of our goodwill, indefinite-lived intangible assets and certain of our oil and gas properties, which resulted in our recording an aggregate of $907.6 million of asset impairment charges in the fourth quarter of 2008 (Note 2). If the price of our common stock does not increase over the near-term, we may be required to record additional impairment charges associated with our remaining $366.2 million of goodwill as of December 31, 2008 that is related to our Contracting Services ($73.7 million) and Shelf Contracting ($292.5 million) businesses. Further, our contracting services also may be negatively impacted by declining commodity prices as such may cause our customers, primarily oil and gas companies, to curtail or eliminate capital spending. We have stabilized the price for a significant portion of our anticipated oil and gas production for 2009 when we entered into commodity hedges during 2008 which will enable us to minimize our near-term cash flow risks related to declining commodity prices (Note 2). The prices for these contracts are significantly higher than the prices for both crude oil and natural gas as of December 31, 2008 and as of the time of this filing on March 2, 2009. If the prices for crude oil and natural gas do not increase from current levels, our oil and gas revenues may decrease in 2010 and beyond, perhaps significantly, absent increases in production amounts.

Note 2 — Summary of Significant Accounting Policies

Principles of Consolidation

Our consolidated financial statements include the accounts of majority-owned subsidiaries and variable interest entities in which we are the primary beneficiary. The equity method is used to account for investments in affiliates in which we do not have majority ownership, but have the ability to exert significant influence. We account for our Deepwater Gateway and Independence Hub investments under the equity method of accounting. Minority interests represent minority shareholders' proportionate share of the equity in CDI and Kommandor LLC. All material intercompany accounts and transactions have been eliminated. Certain reclassifications were made to previously reported amounts in the consolidated financial statements and notes thereto to make them consistent with the current presentation format, including the separate line disclosures of goodwill, oil and gas property impairment charges and exploration expense in the consolidated statements of operations reflecting the material amount of such charges in 2008.

Use of Estimates

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

Cash and Cash Equivalents

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

Statement of Cash Flow Information

As of December 31, 2008 and 2007, we had $35.4 million and $34.8 million, respectively, of restricted cash included in other assets (Note 8), all of which was related to funds required to be escrowed to cover decommissioning liabilities associated with the acquisition of the South Marsh Island Block 130 property in 2002. Under the purchase agreement for that property, we are obligated to escrow 50% of revenues on the first $20 million of production escrow and then 37.5% of revenues on production until a total of $33 million is escrowed. At December 31, 2008 the full escrow requirement under this agreement has been met and is available for the future decommissioning of this field.

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

	Years Ended December 31,		
	2008	2007	2006
Interest paid, net of interest capitalized	$ 53,000	$ 71,706	$ 26,104
Income taxes paid	$ 106,624	$ 203,873	$ 56,972

Non-cash investing activities for the years ended December 31, 2008, 2007 and 2006 included $78.5 million, $90.7 million and $39.0 million, respectively, related to accruals of capital expenditures. The accruals have been reflected in the consolidated balance sheet as an increase in property and equipment and accounts payable.

Short-term Investments

Short-term investments are available-for-sale instruments that we expect to realize in cash within one year. These investments are stated at cost, which approximates market value. Any unrealized holding gains or losses are reported in accumulated other comprehensive income (loss) until realized. We did not hold these types of securities at December 31, 2008 and 2007.

Accounts Receivable and Allowance for Uncollectible Accounts

Accounts receivable are stated at the historical carrying amount net of write-offs and allowance for uncollectible accounts. The amount of our net accounts receivable approximate fair value. We establish an allowance for uncollectible accounts receivable based on historical experience and any specific customer collection issues that we have identified. Uncollectible accounts receivable are written off when a settlement is reached for an amount that is less than the outstanding historical balance or when we have determined that the balance will not be collected (Note 20).

Inventories

We had inventory totaling $32.2 million at December 31, 2008 and $29.9 million at December 31, 2007. Our inventory primarily represents the cost of supplies to be used in our oil and gas drilling and development activities, primarily drilling pipe, tubulars and certain wellhead equipment, including two subsea trees. These costs will be partially reimbursed by third party participants in wells supplied with these materials. Our inventories are stated at the lower of cost or market. At December 31, 2008, we recorded a $2.4 million charge to cost of sales to reduce our inventory to its lower of cost or market value as of that date.

Property and Equipment

Overview. Property and equipment, both owned and under capital leases, are recorded at cost. The following is a summary of the components of property and equipment (dollars in thousands):

	Estimated Useful Life	2008	2007
Vessels	10 to 30 years	$ 1,941,733	$ 1,566,720
Oil and gas leases and related equipment	Units-of-Production	2,564,851	2,354,392
Machinery, equipment, buildings and leasehold improvements	5 to 30 years	238,842	167,449
Total property and equipment		$ 4,745,426	$ 4,088,561

The cost of repairs and maintenance is charged to expense as incurred, while the cost of improvements is capitalized. Total repair and maintenance expenses totaled $72.4 million, $44.1 million and $51.0 million for the years ended December 31, 2008, 2007 and 2006, respectively. Included in machinery, equipment, buildings and leasehold improvements were $19.1 million and $9.8 million of capitalized software costs at December 31, 2008 and 2007, respectively. Total amount charged to income related to such costs was $1.2 million, $0.3 million and $0.2 million for the year ended December 31, 2008, 2007 and 2006, respectively.

For long-lived assets to be held and used, excluding goodwill, we base our evaluation of recoverability on impairment indicators such as the nature of the assets, the future economic benefit of the assets, any historical or future profitability measurements and other external market conditions or factors that may be present. If such impairment indicators are present or other factors exist that indicate the carrying amount of the asset may not be recoverable, we determine whether an impairment has occurred through the use of an undiscounted cash flow analysis of the asset at the lowest level for which identifiable cash flows exist. Our marine vessels are assessed on a vessel by vessel basis, while our ROVs are grouped and assessed by asset class. If an impairment has occurred, we recognize a loss for the difference between the carrying amount and the fair value of the asset. The fair value of the asset is measured using quoted market prices or, in the absence of quoted market prices, is based on an estimate of discounted cash flows. There were no such impairments related to our vessels during 2008, 2007 and 2006.

Assets are classified as held for sale when we have a formalized plan for disposal of certain assets and those assets meet the held for sale criteria. Assets classified as held for sale are included in other current assets. There were no assets meeting the requirements to be classified as assets held for sale at December 31, 2008 and 2007.

Depreciation and Depletion. Depletion for our oil and gas properties is calculated on a unit-of-production basis. The calculation is based on the estimated remaining oil and gas proved and proved developed reserves. Depreciation for all other property and equipment is provided on a straight-line basis over the estimated useful lives of the assets.

Oil and Gas Properties. Almost all of our interests in oil and gas properties are located offshore in the Gulf of Mexico and located in waters regulated by the United States. We follow the successful efforts method of accounting for our natural gas and oil exploration and development activities. Under this method, the costs of successful wells and leases containing productive reserves are capitalized. Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized and are reflected as a reduction of investing cash flow in the accompanying consolidated statements of cash flow. Costs incurred relating to unsuccessful exploratory wells are expensed in the period when the drilling is determined to be unsuccessful and are included as a reconciling item to net income (loss) in operating activities in the accompanying consolidated statements of cash flow. See "— Exploratory Costs" below.

Proved Properties. We assess proved oil and gas properties for possible impairment at least annually or when events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. We recognize an impairment loss as a result of a triggering event and when the estimated undiscounted future cash flows from a property are less than the carrying value. If an impairment is indicated, the cash flows are discounted at a rate approximate to our cost of capital and compared to the carrying value for determining the amount of the impairment loss to record. Estimated future cash flows are based on management's expectations for the future and include estimates of crude oil and natural gas reserves and future commodity prices and operating costs. Downward revisions in estimates of reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate a property impairment. We recorded approximately $215.7 million and $64.1 million of property impairments in 2008 and 2007, respectively, primarily related to downward reserve revisions, weak end of life well performance in some of our domestic properties and fields lost as a result of Hurricanes Gustav and Ike and the reassessment of the economics of some of our marginal fields in light of current oil and gas market conditions. During 2006, no impairment of proved oil and gas properties was recorded.

Unproved Properties. We also periodically assess unproved properties for impairment based on exploration and drilling efforts to date on the individual prospects and lease expiration dates. Management's assessment of the results of exploration activities, availability of funds for future activities and the current and projected political climate in areas in which we operate also impact the amounts and timing of impairment provisions. During 2008 and 2007, we recorded $8.9 million and $9.9 million, respectively, of impairment related to unproved oil and gas properties. Such impairments were included in exploration expenses for our Oil and Gas segment. During 2006, no impairment of unproved oil and gas properties was recorded.

Exploratory Costs. The costs of drilling an exploratory well are capitalized as uncompleted or "suspended" wells temporarily pending the determination of whether the well has found proved reserves. If proved reserves are not found, these capitalized costs are charged to expense. A determination that proved reserves have been found results in the continued capitalization of the drilling costs of the well and its reclassification as a well containing proved reserves. At times, it may be determined that an exploratory well may have found hydrocarbons at the time drilling is completed, but it may not be possible to classify the reserves at that time. In this case, we may continue to capitalize the drilling costs as an uncompleted, or "suspended," well beyond one year if we can justify its completion as a producing well and we are making sufficient progress assessing the reserves and the economic and operating viability of the project. If reserves are not ultimately deemed proved or economically viable, the well is considered impaired and its costs, net of any salvage value, are charged to expense.

Occasionally, we may choose to salvage a portion of an unsuccessful exploratory well in order to continue exploratory drilling in an effort to reach the target geological structure/formation. In such cases, we charge only the unusable portion of the well bore to dry hole exploration expense, and we continue to capitalize the costs associated with the salvageable portion of the well bore which increase the capital cost basis of the new exploratory well. In certain situations, the well bore may be carried for more than one year beyond the date drilling in the original well bore was suspended. This may reflect the need to obtain, and/or analyze the availability of, equipment or crews or other activities necessary to pursue the targeted reserves or evaluate new or reprocessed seismic and geographic data. If, after we analyze the new information and conclude that we will not reuse the well bore or if the new exploratory well is determined to be unsuccessful after we complete drilling, we will charge all the capitalized costs to dry hole exploration expense. During the year ended December 31, 2008, 2007 and 2006, we incurred $27.7 million, $20.2 million and $38.3 million, respectively, of exploratory expense; including $18.8 million, $10.3 million and $38.3 million of dry hole expense. See "— Note 7 — Oil and Gas Properties" for detailed discussion of our exploratory activities.

Property Acquisition Costs. Acquisitions of producing properties are recorded at the value exchanged at closing together with an estimate of our proportionate share of the discounted decommissioning liability assumed in the purchase based upon the working interest ownership percentage.

Properties Acquired from Business Combinations. Properties acquired through business combinations are recorded at their fair value. In determining the fair value of the proved and unproved properties, we prepare estimates of oil and gas reserves. We estimate future prices to apply to the estimated reserve quantities acquired and the estimated future operating and development costs to arrive at our estimates of future net revenues. For the fair value assigned to proved reserves, the future net revenues are discounted using a market-based weighted average cost of capital rate determined to be appropriate at the time of the acquisition. To compensate for inherent risks of estimating and valuing unproved reserves, probable and possible reserves are reduced by additional risk weighting factors. See Note 4 for a detailed discussion of our acquisition of Remington.

Capitalized Interest. Interest from external borrowings is capitalized on major projects until the assets are ready for their intended use. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful lives of the assets in the same manner as the underlying assets. The total of our interest expense capitalized during each of the three years ended December 31, 2008, 2007 and 2006 was $42.1 million, $31.8 million and $10.6 million, respectively.

Equity Investments

We periodically review our investments in Deepwater Gateway and Independence Hub for impairment. Under the equity method of accounting, an impairment loss would be recorded whenever the fair value of an equity investment is determined to be below its carrying amount and the reduction is considered to be other than temporary. In judging "other than temporary," we would consider the length of time and extent to which the fair value of the investment has been less than the carrying amount of the equity investment, the near-term and long-term operating and financial prospects of the equity company and our longer-term intent of retaining the investment in the entity. During 2007, CDI determined that there was an other than temporary impairment in its investment of Offshore Technology Solutions Limited ("OTSL") and the full value of CDI's investment in OTSL was impaired and CDI recognized equity losses of OTSL, inclusive of the impairment charge, of $10.8 million in 2007 (Note 9).

Goodwill and Other Intangible Assets

Under Statement of Financial Accounting Standard No. 142, Goodwill and Other Intangible Assets ("SFAS No. 142"), we are required to perform an annual impairment analysis of goodwill and intangible assets. We elected November 1 to be the annual impairment assessment date for goodwill and other intangible assets. However, we could be required to evaluate the recoverability of goodwill and other intangible assets prior to the required annual assessment date if we experience disruption to the business, unexpected significant declines in operating results, divestiture of a significant component of the business, emergence of unanticipated competition, loss of key personnel or a sustained decline in market capitalization. Our goodwill impairment test involves a comparison of the fair value with our carrying amount. The fair value is determined using discounted cash flows and other market-related valuation models.

We completed our annual goodwill impairment test as of November 1, 2008 based on six reporting units. Goodwill impairment is determined using a two-step process. The first step is to identify if a potential impairment exists by comparing the fair value of the reporting unit with its carrying amount, including goodwill. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is not considered to have a potential impairment and the second step of the impairment test is not necessary. However, if the carrying amount of a reporting unit exceeds its fair value, the second step is performed to determine if goodwill is impaired and to measure the amount of impairment loss to recognize, if any.

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

We use both the income approach and market approach to estimate the fair value of our reporting units under the first step. Under the income approach, a discounted cash flow analysis is performed requiring us to make various judgmental assumptions about future revenue, operating margins, growth rates and discount rates. These judgmental assumptions are based on our budgets, long-term business plans, reserve reports, economic projections, anticipated future cash flows and market place data. Under the market approach, the fair value of each reporting unit is calculated by applying an average peer total invested capital EBITDA (defined as earnings before interest, income taxes and depreciation and amortization) multiple to the 2009 budgeted EBITDA for each reporting unit. Judgment is required when selecting peer companies that operate in the same or similar lines of business and are potentially subject to the same corresponding economic risks.

The recent economic downturn and weakness in the equity and credit capital markets has led to increased uncertainty regarding the outlook of the global economy. This uncertainty coupled with the probable decrease in the near-term global demand for oil and gas has resulted in commodity price declines over the second half of 2008, with significant declines occurring in the fourth quarter of 2008. Declines in oil and gas prices negatively impacts our operating results and cash flow. We believe that these events have contributed to a significant decline in our stock price and corresponding market capitalization. Based on the first step of the 2008 goodwill impairment analysis, the carrying amount of two of our reporting units exceeded their fair value as calculated under the first step, which required us to perform the second step of the impairment test. In the second step, the fair value of tangible and certain intangible assets was generally estimated using discounted cash flow analysis. The fair value of intangibles with indefinite lives such as trademark was calculated using a royalty rate method. Based on our 2008 goodwill impairment analysis, we recorded a $704.3 million and $8.3 million impairment expense in our Oil and Gas and Contracting Services segments, respectively. In addition, we recorded a $2.4 million impairment expense related to a trade name used by Helix RDS. This impairment expense was recorded in the Contracting Services segment.

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

	Contracting Services	Shelf Contracting	Oil and Gas	Total
Balance at December 31, 2006	$ 88,294	$ 26,666	$ 707,596	$ 822,556
Remington acquisition (Note 4)	—	—	4,796	4,796
Well Ops SEA Pty Ltd. acquisition (Note 6)	6,001	—	—	6,001
Horizon acquisition (Note 5)	—	257,340	—	257,340
Tax and other adjustments	(1,070)	135	—	(935)
Balance at December 31, 2007	$ 93,225	$ 284,141	$ 712,392	$ 1,089,758
Impairment expense	(8,274)	—	(704,311)	(712,585)
Goodwill written off related to sale of business	—	—	(8,081)	(8,081)
Horizon acquisition (Note 5)	—	8,328	—	8,328
Well Ops SEA Pty Ltd. acquisition (Note 6)	1,029	—	—	1,029
Other adjustments(1)	(12,231)	—	—	(12,231)
Balance at December 31, 2008	$ 73,749	$ 292,469	$ —	$ 366,218

(1) Reflects foreign currency adjustment for certain amount of our goodwill.

A summary of other intangible assets, net, is as follows (in thousands):

	As of December 31, 2008		As of December 31, 2007	
	Gross Amount	Accumulated Amortization	Gross Amount	Accumulated Amortization
Contract backlog	$ 2,960	$ (1,330)	$ 2,960	$ (387)
Customer relationships	12,420	(3,784)	14,470	(2,422)
Non-compete agreements	6,752	(6,262)	7,460	(2,710)
Patent technology	928	(146)	1,264	(136)
Trade name	5,643	(2,429)(1)	7,512	(3)
Intellectual property	1,458	(668)	2,008	(778)
Total	$ 30,161	$ (14,619)	$ 35,674	$ (6,436)

(1) Amortization amount reflects an impairment charge recorded to this indefinite lived intangible assets in fourth quarter of 2008.

Total amortization expenses for intangible assets for the years ended December 31, 2008, 2007, and 2006 was $7.2 million, $3.3 million and $2.3 million, respectively. A summary of the estimated amortization expense for the next five years is as follows (in thousands):

Years Ended December 31,		
2009	$	3,717
2010		1,776
2011		1,776
2012		1,743
2013		1,088

Recertification Costs and Deferred Drydock Charges

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

As of December 31, 2008 and 2007, capitalized deferred drydock charges included within Other Assets in the accompanying consolidated balance sheet (Note 8) totaled $38.6 million and $48.0 million, respectively. During the years ended December 31, 2008, 2007 and 2006, drydock amortization expense was $26.0 million, $23.0 million and $12.0 million, respectively.

Accounting for Decommissioning Liabilities

We account for our decommissioning liabilities in accordance with Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations ("SFAS No. 143"). This statement requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying cost of the asset. Our asset retirement obligations consist of estimated costs for dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. An asset retirement obligation and the related asset retirement cost are recorded when an asset is first constructed or purchased. The asset retirement cost is determined and discounted to present value using a credit-adjusted risk-free rate. After the initial recording, the liability is increased for the passage of time, with the increase being reflected as accretion expense in the statement of operations. Subsequent adjustment in the cost estimates are reflected in the liability and the amounts continue to be accreted over the useful life of the related long-lived asset.

SFAS No. 143 calls for measurements of asset retirement obligations to include, as a component of expected costs, an estimate of the price that a third party would demand, and could expect to receive, for bearing the uncertainties and unforeseeable circumstances inherent in the obligations, sometimes referred to as a market-risk premium. To date, the oil and gas industry has no examples of credit-worthy third parties who are willing to assume this type of risk, for a determinable price, on major oil and gas production facilities and pipelines. Therefore, because determining such a market-risk premium would be an arbitrary process, we excluded it from our SFAS No. 143 estimates.

The following table describes the changes in our asset retirement obligations for the year ended 2008 and 2007 (in thousands):

	2008	2007
Asset retirement obligation at January 1,	$ 217,479	$ 167,671
Liability incurred during the period	6,819	27,822
Liability settled during the period	(47,703)	(41,892)
Revision in estimated cash flows	36,121	52,903
Accretion expense (included in depreciation and amortization)	13,065	10,975
Asset retirement obligations at December 31,	$ 225,781	$ 217,479

Revenue Recognition

Contracting Services Revenues

Revenues from Contracting Services and Shelf Contracting are derived from contracts that traditionally have been of relatively short duration; however, beginning in 2007, contract durations have started to become longer-term. These contracts contain either lump-sum turnkey provisions or provisions for specific time, material and equipment charges, which are billed in accordance with the terms of such contracts. We recognize revenue as it is earned at estimated collectible amounts. Further, we record revenues net of taxes collected from customers and remitted to governmental authorities.

Unbilled revenue represents revenue attributable to work completed prior to period end that has not yet been invoiced. All amounts included in unbilled revenue at December 31, 2008 and 2007 are expected to be billed and collected within one year.

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

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

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

Under the percentage-of-completion method, we recognize estimated contract revenue based on costs incurred to date as a percentage of total estimated costs. Changes in the expected cost of materials and labor, productivity, scheduling and other factors affect the total estimated costs. Additionally, external factors, including weather and other factors outside of our control, may also affect the progress and estimated cost of a project's completion and, therefore, the timing of income and revenue recognition. We routinely review estimates related to our contracts and reflect revisions to profitability in earnings on a current basis. If a current estimate of total contract cost indicates an ultimate loss on a contract, we recognize the projected loss in full when it is first determined. We recognize additional contract revenue related to claims when the claim is probable and legally enforceable. If dependable, estimates of progress cannot be made or for which inherent hazards make estimates doubtful, the completed contract method is used instead of percentage-of-completion method.

A number of our longer term pipelay contracts have been adversely affected by delays in the delivery of the Caesar. We believe two of our contracts qualify as loss contracts as defined under SOP 81-1 "Accounting for Performance of Construction-Type and Certain Production-Type Contracts". Accordingly, we have estimated the future shortfall between our anticipated future revenues versus future costs. For one contract expected to be completed in May 2009, our estimated loss is anticipated to be approximately $0.8 million. Under a second contract, which was terminated, we have a potential future liability of up to $25 million with our estimated future loss under this contract totaling $9.0 million, which was accrued for as of December 31, 2008. We have prepaid $7.2 million of such potential damages related to this terminated contact. If the potential damages exceed $7.2 million we will be required to pay additional funds but to the extent they are less that $7.2 million we would be entitled to cash refund from the contracting party. We will continue to monitor our exposure under this contract in 2009.

Oil and Gas Revenues

We record revenues from the sales of crude oil and natural gas when delivery to the customer has occurred, title has transferred, prices are fixed and determinable and collection is reasonably assured. This occurs when production has been delivered to a pipeline or a barge lifting has occurred. We may have an interest with other producers in certain properties. In this case, we use the entitlements method to account for sales of production. Under the entitlements method, we may receive more or less than our entitled share of production. If we receive more than our entitled share of production, the imbalance is treated as a liability. If we receive less than our entitled share, the imbalance is recorded as an asset. As of December 31, 2008, the net imbalance was a $1.7 million asset and was included in Other Current Assets ($7.5 million) and Accrued Liabilities ($5.8 million) in the accompanying consolidated balance sheet.

Income Taxes

Deferred income taxes are based on the differences between financial reporting and tax bases of assets and liabilities. We utilize the liability method of computing deferred income taxes. The liability method is based on the amount of current and future taxes payable using tax rates and laws in effect at the balance sheet date. Income taxes have been provided based upon the tax laws and rates in the countries in which operations are conducted and income is earned. A valuation allowance for deferred tax assets is recorded when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. We consider the undistributed earnings of our principal non-U.S. subsidiaries to be permanently reinvested. The deconsolidation of CDI's net income for tax return filing purposes after its initial public offering did not have a material impact on our consolidated results of operations; however, because of our inability to recover our tax basis in CDI tax free, a long term deferred tax liability is provided for any incremental increases to the book over tax basis.

It is our policy to provide for uncertain tax positions and the related interest and penalties based upon management's assessment of whether a tax benefit is more likely than not to be sustained upon examination by tax authorities. At December 31, 2008, we believe we have appropriately accounted for any unrecognized tax benefits. To the extent we prevail in matters for which a liability for an unrecognized tax benefit is established or are required to pay amounts in excess of the liability, our effective tax rate in a given financial statement period may be affected.

Foreign Currency

The functional currency for our foreign subsidiaries, Well Ops (U.K.) Limited and Helix RDS, is the applicable local currency (British Pound), and the functional currency of Well Ops SEA Pty. Ltd. is its applicable local currency (Australian Dollar). Results of operations for these subsidiaries are translated into U.S. dollars using average exchange rates during the period. Assets and liabilities of these foreign subsidiaries are translated into U.S. dollars using the exchange rate in effect at December 31, 2008 and 2007 and the resulting translation adjustment, which was an unrealized (loss) gain of $(71.1) million and $3.7 million, respectively, is included in accumulated other comprehensive income, a component of shareholders' equity. All foreign currency transaction gains and losses are recognized currently in the statements of operations.

Canyon Offshore, Inc., our ROV subsidiary, has operations in the United Kingdom and Asia Pacific. Further, CDI has subsidiaries with operations in the Middle East, Southeast Asia, the Mediterranean, Australia and Latin America. Canyon's and CDI's international subsidiaries conduct the majority of their operations in these regions in U.S. dollars which is considered to be their functional currency. When currencies other than the U.S. dollar are to be paid or received, the resulting transaction gain or loss is recognized in the statements of operations. These amounts for each of the years ended December 31, 2008, 2007 and 2006 were not material to our results of operations or cash flows.

Our foreign currency gains (losses) totaled ($9.8) million in 2008, ($0.5) million in 2007 and $0.1 million in 2006.

Derivative Instruments and Hedging Activities

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

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

Further, when we have obligations and receivables with the same counterparty, the fair value of the derivative liability and asset are presented at net value.

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

Commodity Price Risks

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

We have entered into various costless collar and swap contracts to stabilize cash flows relating to a portion of our expected oil and gas production. These contracts qualified for hedge accounting. The aggregate fair value of these derivative instruments was a net asset (liability) of $22.3 million and $(8.1) million as of December 31, 2008 and 2007, respectively.

For the years ended December 31, 2008, 2007 and 2006, we recorded unrealized gains (losses) of approximately $15.0 million, $(8.7) million and $12.1 million, net of tax expense (benefit) of $8.1 million, $(4.7) million and $6.5 million, respectively, in accumulated other comprehensive income, a component of shareholders' equity, as these derivatives were highly effective. All unrealized losses recorded in other comprehensive income in 2008 are expected to be reclassified into earnings within the next 12 months. During 2008, 2007 and 2006, we reclassified approximately $(17.1) million, $0.5 million and $9.0 million, respectively, of gains (losses) from other comprehensive income to Oil and Gas revenues upon the sale of the related oil and gas production. In addition, during 2008 we recorded a gain of approximately $6.4 million in other non-operating income/expense as a result of the discontinuation of hedge accounting due to production shut-ins and the resultant deferrals caused by Hurricanes Gustav and Ike. No hedge ineffectiveness was recorded during the years ended December 31, 2007 and 2006.

As of December 31, 2008, we have the following volumes under derivatives and forward sales contracts related to our oil and gas producing activities totaling 2,222 MBbl of oil and 30,489 Mmcf of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			(per barrel)
January 2009 — June 2009	Collar	50.25 MBbl	$75.00 — $89.95

January 2009 — March 2009	Swap	40 MBbl	$57.16
January 2009 — December 2009	Forward Sales	150 MBbl	$71.79
Natural Gas:			(per Mcf)
January 2009 — December 2009	Collar	1,029 Mmcf	$7.00 — $7.90
January 2009 — March 2009	Swap	529 Mmcf	$6.69
January 2009 — December 2009	Forward Sales	1,379 Mmcf	$8.23

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

Variable Interest Rate Risks

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

In September 2006, we entered into various interest rate swaps to stabilize cash flows relating to a portion of our interest payments on our Term Loan (Note 11). These interest rate swaps qualified for hedge accounting. On December 21, 2007, we prepaid a portion of our Term Loan which reduced the notional amount of our interest rate swaps and caused our hedges to become ineffective. As a result, the interest rate swaps no longer qualified for hedge accounting treatment under SFAS No. 133. On January 31, 2008, we re-designated these swaps as cash flow hedges with respect to our outstanding LIBOR-based debt; however, at September 30, 2008, based on the hypothetical derivatives method, we assessed the hedges were not highly effective, and as such, no longer qualified for hedge accounting. During the year ended December 31, 2008 and 2007, we recognized $5.3 million and $0.6 million, respectively, of unrealized losses as other expense as a result of the change in fair value of our interest rate swaps. As of December 31, 2008 and December 31, 2007, the aggregate fair value of the derivative instruments was a net liability of $8.0 million and $4.7 million, respectively. During the year ended December 31, 2008 and 2007, we reclassified approximately $1.7 million and $(0.4) million of (gains) losses, respectively, from other accumulated comprehensive income (loss), a component of shareholders' equity, to interest expense.

In addition, in April 2008, CDI entered into a two-year interest rate swap to stabilize cash flows relating to a portion of its variable interest payments on the CDI term loan. As of December 31, 2008, this interest rate swap was highly effective and qualified for hedge accounting. The fair value of the hedge instrument was a liability of $1.7 million as of December 31, 2008. Based on future three-month LIBOR interest rate curves as of December 31, 2008, $0.9 million of the unrealized loss from CDI's interest rate swap recorded in other comprehensive income at December 31, 2008 would be reclassified into earnings within the next 12 months.

Foreign Currency Exchange Risks

Because we operate in various regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar. We entered into various foreign currency forwards to stabilize expected cash outflows relating to certain shipyard contracts where the contractual payments are denominated in euros and expected cash outflows relating to certain vessel charters denominated in British pounds. The aggregate fair value of the foreign currency forwards as of December 31, 2008 and December 31, 2007 was a net asset (liability) of ($0.9) million and $1.4 million, respectively. For the year ended December 31, 2008 we recorded unrealized gains of approximately $0.1 million in accumulated other comprehensive income, a component of shareholders' equity, all of which are expected to be reclassified into earnings within the next 12 months. For the year ended December 31, 2007, we recorded unrealized gains of approximately $1.1 million, net of tax expense of $0.5 million, in accumulated other comprehensive income. In 2008, we recorded approximately $0.8 million of unrealized losses, net of tax benefit of $0.4 million, as other expense as a result of the change in fair value of our foreign currency forwards that did not qualify for hedge accounting.

Earnings per Share

Basic earnings per share (“EPS”) is computed by dividing the net income (loss) available to common shareholders by the weighted-average shares of common stock outstanding. The calculation of diluted EPS is similar to basic EPS, except the denominator includes dilutive common stock equivalents and the income included in the numerator excludes the effects of the impact of dilutive common stock equivalents, if any. The computation of basic and diluted per share amounts for the years ended December 31, 2008, 2007 and 2006 were as follows (in thousands):

	Year Ended December 31,					
	2008		2007		2006	
	Loss	Shares	Income	Shares	Income	Shares
Earnings (loss) applicable per common share — Basic	$ (634,040)	90,650	$ 316,762	90,086	$ 344,036	84,613
Effect of dilutive securities:						
Stock options	—	—	—	376	—	449
Restricted shares	—	—	—	291	—	160
Employee stock purchase plan	—	—	—	6	—	12
Convertible Senior Notes	—	—	—	1,548	—	1,009
Convertible preferred stock	—	—	3,716	3,631	3,358	3,631
Earnings (loss) applicable per common share — Diluted	$ (634,040)	90,650	$ 320,478	95,938	$ 347,394	89,874

We had a net loss applicable to common shareholders in 2008. Accordingly, our diluted per share calculation for 2008 is equivalent to our basic loss per share calculation because it excludes any assumed exercise or conversion of common stock equivalents because they are deemed to be anti-dilutive, meaning their inclusion would have reduced the reported net loss per share for 2008. Shares that otherwise would have been included in the diluted per share amount include, 0.3 million shares associated with stock options whose exercise price was less than the average price for our common stock for 2008, 0.1 million shares associated with unvested restricted shares and 3.6 million equivalent shares of common stock from the assumed conversion of our convertible preferred stock. The diluted earnings (loss) per share calculation also excludes the consideration of adding back the $3.2 million of dividends and related costs associated with the convertible preferred stock that otherwise would have been added back to net income if assumed conversion of the shares was dilutive during 2008. There were no stock options outstanding whose exercise price was greater than the average price for our common stock for each of the years ending December 31, 2008, 2007 and 2006. Net income for the diluted earnings per share calculation for the years ended December 31, 2007 and 2006 were adjusted to add back the preferred stock dividends and accretion on 3.6 million shares.

Stock Based Compensation Plans

Prior to January 1, 2006, we used the intrinsic value method of accounting for our stock-based compensation. Accordingly, no compensation expense was recognized when the exercise price of an employee stock option was equal to the common share market price on the grant date and all other terms were fixed. In addition, under the intrinsic value method, on the date of grant for restricted shares, we recorded unearned compensation (a component of shareholders' equity) that equaled the product of the number of shares granted and the closing price of our common stock on the business day prior to the grant date, and expense was recognized over the vesting period of each grant on a straight-line basis.

We did not grant any stock options during the three-year period ended December 31, 2008. The fair value of shares issued under the Employee Stock Purchase Plan was based on the 15% discount received by the employees. The estimated fair value of the options is amortized to expense over the vesting period. See "— Note 14 — Employee Benefit Plans" for discussion of our stock compensation.

Accounting for Sales of Stock by Subsidiary

We recognize a gain or loss upon the direct sale or issuance of equity by our subsidiaries if the sales price differs from our carrying amount, provided that the sale of such equity is not part of a broader corporate reorganization. See "— Note 3" and "— Note 5" for discussion of CDI's initial public offering and common stock issuance as part of the acquisitio of Horizon Offshore, Inc. (“Horizon”). Effective January 1, 2009, we have changed our accounting policy of recognizing a gain or loss upon any future direct sale or issuance of equity by our subsidiaries if the sales price differs from our carrying amount to be in accordance with recently issued accounting requirements, in which a gain or loss will only be recognized when loss of control of a consolidated subsidiary occurs. See “Recently Issued Accounting Principles” below.

Consolidation of Variable Interest Entities

FASB Interpretation No. 46 (R), Consolidation of Variable Interest Entities (“FIN 46”) requires the consolidation of variable interest entities in which an enterprise absorbs a majority of the entity’s expected losses, receives a majority of the entity’s expected residual returns, or both, as a result of ownership, contractual or other financial, interests in the entity. See Note 10 related to our consolidated variable interest entities.

Fair Value of Financial Instruments

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and our long-term debt. The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the highly liquid nature of these instruments. The carrying amount and estimated fair value of our debt, including current maturities as of December 31, 2008 and 2007 follow (amount in thousands):

	2008 Carrying Value	Fair Value	2007 Carrying Value	Fair Value
Term Loan (1)	$ 419,093	$ 251,455	$ 423,418	$ 410,715
Revolving Credit Facility (2)	349,500	349,500	18,000	18,000
Cal Dive Term Loan (2)	315,000	315,000	375,000	375,000
Convertible Senior Notes (1)	300,000	136,383	300,000	442,485
Senior Unsecured Notes (1)	550,000	261,250	550,000	559,625
MARAD Debt (3)	123,449	132,609	127,463	126,061
Loan Notes (4)	5,000	5,000	6,506	6,506
Total	$ 2,062,042	$ 1,451,197	$ 1,800,387	$ 1,938,392

(1) The fair values of these instruments were based on quoted market prices as of December 31, 2008 and 2007. The fair values were estimated using level 1 inputs as defined by SFAS No. 157 using the market approach (see "Recently Issued Accounting Principles" below).

(2) The carrying values of these credit facilities approximate fair value.

(3) The fair value of the MARAD debt was determined by a third-party evaluation of the remaining average life and outstanding principal balance of the MARAD indebtedness as compared to other government guaranteed obligations in the market place with similar terms. The fair value of the MARAD debt was estimated using level 2 inputs as defined by SFAS 157 using the cost approach (see "Recently Issued Accounting Principles" below).

(4) The carrying value of the loan notes approximates fair value as the maturity date of the loan notes is less than one year.

Major Customers and Concentration of Credit Risk

The market for our products and services is primarily the offshore oil and gas industry. Oil and gas companies spend capital on exploration, drilling and production operations expenditures, the amount of which is generally dependent on the prevailing view of the future oil and gas prices that are subject to many external factors which may contribute to significant volatility in future prices. Our customers consist primarily of major oil and gas companies, well-established oil and pipeline companies and independent oil and gas producers and suppliers. We perform ongoing credit evaluations of our customers and provide allowances for probable credit losses when necessary. The percent of consolidated revenue of major customers, those whose total represented 10% or more of our consolidated revenues, was as follows: 2008 — Louis Dreyfus Energy Services (10%) and Shell Offshore, Inc. (11%); 2007 — Louis Dreyfus Energy Services (13%) and Shell Offshore, Inc. (10%); and 2006 — Louis Dreyfus Energy Services (10%) and Shell Trading (US) Company (10%). All of these customers were purchasers of our oil and gas production. We estimate that in 2008 we provided subsea services to over 200 customers.

Recently Issued Accounting Principles

In September 2006, the FASB issued Statement No. 157, Fair Value Measurements ("SFAS No. 157"). SFAS No. 157 was originally effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. The FASB agreed to defer the effective date of SFAS No. 157 for all nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis. We adopted the provisions of SFAS No. 157 on January 1, 2008 for assets and liabilities not subject to the deferral and adopted this standard for all other assets and liabilities on January 1, 2009. The adoption of SFAS No. 157 had immaterial impact on our results of operations, financial condition and liquidity.

SFAS No. 157, among other things, defines fair value, establishes a consistent framework for measuring fair value and expands disclosure for each major asset and liability category measured at fair value on either a recurring or nonrecurring basis. SFAS No. 157 clarifies that fair value is an exit price, representing the amount that would be received to sell an asset, or paid to transfer a liability, in an orderly transaction between market participants. SFAS No. 157 establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value as follows:

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

Assets and liabilities measured at fair value are based on one or more of three valuation techniques noted in SFAS No. 157. The valuation techniques are as follows:

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

The following table provides additional information related to assets and liabilities measured at fair value on a recurring basis at December 31, 2008 (in thousands):

	Level 1	Level 2	Level 3	Total	Valuation Technique
Assets:					
Oil and gas swaps and collars	–	$ 22,307	–	$ 22,307	(c)
Liabilities:					
Foreign currency forwards	–	940	–	940	(c)
Interest rate swaps	–	7,967	–	7,967	(c)
Total	–	$ 8,907	–	$ 8,907	

In December 2007, the FASB issued Statement No. 141 (Revised), Business Combinations (“SFAS No. 141(R)”). SFAS No. 141 (R) requires the acquiring entity in a business combination to recognize all the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. It also requires that the costs incurred related to the acquisition be charged to expense as incurred, when previously these costs were capitalized as part of the acquisition cost of the asset or business. The provisions of SFAS No. 141(R) are effective for fiscal years beginning after December 15, 2008 and should be adopted prospectively. We adopted the provisions of SFAS No. 141(R) on January 1, 2009 and it had no impact on our results of operations, cash flows and financial condition.

In December 2007, the FASB issued Statement No. 160, Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB 51 (“SFAS No. 160”). SFAS No. 160 improves the relevance, comparability, and transparency of financial information provided to investors by requiring all entities to report noncontrolling (minority) interests in subsidiaries as equity in the consolidated financial statements. The provisions of SFAS No. 160 are effective for fiscal years beginning after December 15, 2008 and required to be adopted prospectively, except the following provisions must be adopted retrospectively:

1. Reclassifying noncontrolling interest from the "mezzanine" to equity, separate from the parents' shareholders' equity, in the statement of financial position; and
2. Recast consolidated net income to include net income attributable to both the controlling and noncontrolling interests. That is, retrospectively, the noncontrolling interests' share of a consolidated subsidiary's income should not be presented in the income statement as "minority interest."

Further, effective January 1, 2009, we have changed our accounting policy of recognizing a gain or loss upon any future direct sale or issuance of equity by our subsidiaries if the sales price differs from our carrying amount to be in accordance with SFAS No. 160, in which a gain or loss will only be recognized when loss of control of a consolidated subsidiary occurs. In January 2009, we sold approximately 13.6 million shares of CDI common stock to CDI for $86 million. This transaction constituted a single transaction and was not part of any planned set of transactions that would result in us having a noncontrolling interest in CDI and reduced our ownership in CDI to approximately 51%. Since we retained control of CDI immediately after the transaction, the approximate $2.9 million loss on this sale will be treated as a reduction of our equity in our consolidated balance sheet. Any future transactions would result in us losing control of CDI and accordingly the gain or loss on those transactions will flow through our earnings.

In March 2008, the FASB issued Statement No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133 (“SFAS No. 161”). SFAS 161 applies to all derivative instruments and related hedged items accounted for under SFAS No. 133. SFAS No. 161 requires entities to provide qualitative disclosures about the objectives and strategies for using derivatives, quantitative data about the fair value of and gains and losses on derivative contracts, and details of credit-risk-related contingent features in their hedged positions. The standard is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged, but not required. We adopted the provisions of SFAS No. 161 on January 1, 2009 and it had no impact on our results of operations, cash flows or financial condition.

In May 2008, the FASB issued FASB Staff Position (“FSP”) APB 14-1, Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement) (“FSP APB 14-1”). The FSP would require the proceeds from the issuance of convertible debt instruments to be allocated between a liability component (issued at a discount) and an equity component. The resulting debt discount would be amortized over the period the convertible debt is expected to be outstanding as additional non-cash interest expense. The effective date of FSP APB 14-1 is for fiscal years beginning after December 15, 2008 and requires retrospective application to all periods reported (with the cumulative effect of the change reported in retained earnings as of the beginning of the first period presented). The FSP does not permit early application. This FSP changes the accounting treatment for our Convertible Senior Notes. FSP APB 14-1 will increase our non-cash interest expense for our past and future reporting periods. On January 1, 2009, we adopted the provisions of FSP APB 14-1. Had this new standard been effective for the years ended December 31, 2008 and 2007, the Company estimates interest expense would have increased by approximately $7.8 million and $7.4 million respectively. Diluted loss per share for the year ended December 31, 2008 would have increased by approximately $0.06 per share and diluted earnings per share for the year ended December 31, 2007 would have decreased by approximately $0.13 per share.

In June 2008, the FASB issued FSP Emerging Issues Task Force 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities ("FSP EITF 03-6-1"). This FSP would require unvested share-based payment awards containing non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) to be included in the computation of basic EPS according to the two-class method. The effective date of FSP EITF 03-6-1 is for fiscal years beginning after December 15, 2008 and requires all prior-period EPS data presented to be adjusted retrospectively (including interim financial statements, summaries of earnings, and selected financial data) to conform with the provisions of this FSP. FSP EITF 03-6-1 does not permit early application. This FSP changes our calculation of basic and diluted EPS and will lower previously reported basic and diluted EPS as weighted-average shares outstanding used in the EPS calculation will increase. Upon adoption on January 1, 2009, the changes resulting from this FSP on our EPS data are listed in the following table:

Earnings per share – Basic

	Reported	Pro Forma	Variance
For the Year Ended:			
2008	$ (6.99)	$ (6.91)	$ 0.08
2007	3.52	3.47	(0.05)
2006	4.07	4.03	(0.04)

Earnings per share – Diluted

	Reported	Pro Forma	Variance
For the Year Ended:			
2008	$ (6.99)	$ (6.91)	$ 0.08
2007	3.34	3.27	(0.07)
2006	3.87	3.81	(0.06)

Also in June 2008, the FASB issued Emerging Issues Task Force Issue No. 07-5, Determining Whether an Instrument (or Embedded Feature) is Indexed to an Entity's Own Stock ("EITF 07-5"). This issue addresses the determination of whether an instrument (or an embedded feature) is indexed to an entity's own stock, which is the first part of the scope exception in paragraph 11(a) of SFAS No. 133. If an instrument (or an embedded feature) that has the characteristics of a derivative instrument under paragraphs 6–9 of SFAS No. 133 is indexed to an entity's own stock, it is still necessary to evaluate whether it is classified in shareholders' equity (or would be classified in shareholders' equity if it were a freestanding instrument). This issue is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application by an entity that has previously adopted an alternative accounting policy is not permitted. While, we do not believe the adoption of this statement will have any material effect on our financial statements, we continue to assess its potential impact on our financial statements.

Note 3 — Initial Public Offering of Cal Dive International, Inc.

In December 2006, we contributed the assets of our Shelf Contracting segment into Cal Dive, our then wholly owned subsidiary. Cal Dive subsequently sold approximately 22.2 million shares of its common stock in an initial public offering and distributed the net proceeds of $264.4 million to us as a dividend. In connection with the offering, CDI also entered into a $250 million revolving credit facility (Note 11). In December 2006, Cal Dive borrowed $201 million under the facility and distributed $200 million of the proceeds to us as a dividend. We recognized an after-tax gain of $96.5 million, net of taxes of $126.6 million as a result of these transactions. We used the proceeds for general corporate purposes. In connection with the offering, together with shares issued to CDI employees immediately after the offering, our ownership of CDI decreased to approximately 73.0% as of December 31, 2006. Our ownership in CDI was further reduced in December 2007 as a result of CDI's stock issuance related to the Horizon acquisition (Note 5). Our ownership in CDI as of December 31, 2008 was approximately 57.2%. In January 2009, we sold CDI approximately 13.6 million shares of its common stock held by us for $86 million. As a result of this transaction, we currently hold an approximate 51% ownership interest in CDI.

Further, in conjunction with the offering, the tax basis of certain CDI's tangible and intangible assets was increased to fair value. The increased tax basis should result in additional tax deductions available to CDI over a period of two to five years. Under the Tax Matters Agreement with CDI, for a period of up to ten years to the extent CDI generates taxable income sufficient to realize the additional tax deductions, it will be required to pay us 90% of the amount of tax savings actually realized from the step-up of the assets. As of December 31, 2008 and 2007, we have a receivable from CDI of approximately $4.5 million and $6.2 million, respectively, related to the Tax Matters Agreement (Note 12).

Note 4 — Acquisition of Remington Oil and Gas Corporation

On July 1, 2006, we acquired 100% of Remington, an independent oil and gas exploration and production company headquartered in Dallas, Texas, with operations concentrated in the onshore and offshore regions of the Gulf Coast, for approximately $1.4 billion in cash and Helix common stock and the assumption of $358.4 million of liabilities. The merger consideration was 0.436 of a share of our common stock and $27.00 in cash for each share of Remington common stock. On July 1, 2006, we issued approximately 13.0 million shares of our common stock to Remington stockholders and funded the cash portion of the Remington acquisition (approximately $806.8 million) and transaction costs (approximately $18.5 million) through a credit.

The Remington acquisition was accounted for as a business combination with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair values, with the excess being recorded in goodwill. The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at the date of acquisition (in thousands):

Current assets	$ 154,293
Property and equipment	863,935
Goodwill	712,392
Other intangible assets (1)	6,800
Total assets acquired	$ 1,737,420
Current liabilities	$ 130,409
Deferred income taxes	204,096
Decommissioning liabilities (including current portion)	22,137
Other non-current liabilities	1,800
Total liabilities assumed	$ 358,442
Net assets acquired	$ 1,378,978

(1) The intangible asset was related to a favorable drilling rig contract and several non-compete agreements between the Company and certain members of senior management. The fair value of the drilling rig contract was $5.0 million at the date of the acquisition, which was capitalized as property and equipment following the drilling of certain successful exploratory wells in 2007. The fair value of the non-compete agreements was $1.8 million, which is being amortized over the term of the agreements (three years) on a straight-line basis, with $0.3 million remaining unamortized at December 31, 2008.

Our oil and gas segment includes the results of the Remington acquisition since the date of purchase. See Note 6 for pro forma combined operating results of the Company and the Remington acquisition for the year ended December 31, 2006.

Note 5 — Acquisition of Horizon Offshore, Inc.

On December 11, 2007, CDI acquired 100% of Horizon, a marine construction services company headquartered in Houston, Texas. Under the terms of the merger, each share of common stock, par value $0.00001 per share, of Horizon was converted into the right to receive $9.25 in cash and 0.625 shares of CDI's common stock. All shares of Horizon restricted stock that had been issued but had not vested prior to the effective time of the merger became fully vested at the effective time of the merger and converted into the right to receive the merger consideration. CDI issued approximately 20.3 million shares of its common stock and paid approximately $300 million in cash to the former Horizon stockholders upon completion of the acquisition. The cash portion of the merger consideration was paid with cash on hand and $375 million of borrowings under CDI's $675 million credit facility, which consists of the fully drawn $375 million senior secured term loan and an additional $300 million senior secured revolving credit facility (Note 11).

The aggregate purchase price, including transaction costs of $7.7 million, was approximately $630 million consisting of $308 million of cash and $322 million of stock. CDI also assumed and repaid approximately $104 million in Horizon debt, including accrued interest and prepayment penalties, and acquired $171 million of cash. Through the acquisition, the Company acquired nine construction vessels, including four pipelay/pipebury barges, one dedicated pipebury barge, one DSV, one combination derrick/pipelay barge and two derrick barges. The acquisition was accounted for as a business combination with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair values. The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at the date of acquisition (in thousands):

Cash	$	170,607
Other current assets		164,664
Property and equipment		336,147
Other long-term assets		15,133
Goodwill		265,668
Intangible assets		9,510
Total assets acquired		961,729
Current liabilities	$	184,678
Deferred income taxes		59,322
Long-term debt		87,641
Other non-current liabilities		100
Total liabilities assumed		331,741
Net assets acquired	$	629,988

The intangible assets relate to the fair value of contract backlog, customer relationships and non-compete agreements between CDI and certain members of Horizon's senior management as follows (dollars in thousands):

	Fair Value	Amortization Period
Customer relationships	$ 3,060	1.5 years
Contract backlog	2,960	5 years
Non-compete agreements	3,000	1 year
Trade name	490	9 years
	$ 9,510	

At December 31, 2008, the net carrying amount for these intangibles was $4.3 million.

The results of Horizon are included in our Shelf Contracting segment in the accompanying consolidated and combined statements of operations since the date of purchase. See Note 6 pro forma combined operating results of the Company and the Horizon acquisition for the years ended December 31, 2007 and 2006.

We recognized a non-cash pre-tax gain of $151.7 million ($98.6 million net of taxes of $53.1 million) in 2007 as our share of CDI's underlying equity increased as a result of CDI's issuance of 20.3 million shares of common stock to former Horizon stockholders, which reduced our ownership to 58.5%. The gain was calculated as the difference in the value of our investment in CDI immediately before and after CDI's stock issuance. As disclosed in Note 3, our ownership of CDI decreased from the approximate 57% at December 31, 2008 to approximately 51% in January 2009.

Note 6 — Other Acquisitions

2007

Well Ops SEA Pty Ltd.

In October 2006, we acquired a 58% interest in Seatrac Pty Ltd. (“Seatrac”) for total consideration of approximately $12.7 million (including $0.2 million of transaction costs), with approximately $9.1 million paid to existing Seatrac shareholders and $3.4 million for subscription of new Seatrac shares. We renamed this entity Well Ops SEA Pty Ltd. (“WOSEA”). WOSEA is a subsea well intervention and engineering services company located in Perth, Australia. On July 1, 2007, we exercised an option to purchase the remaining 42% of WOSEA for approximately $10.1 million and potential additional consideration of approximately $4.6 million, which the former shareholders would be entitled to if WOSEA meets certain financial performance objectives over a five-year period commencing on our date of purchase. This purchase was accounted for as a business combination with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair value, with the excess being recorded as goodwill. The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at July 1, 2007 (in thousands):

Cash and cash equivalents	$	2,631
Other current assets		4,279
Property and equipment		9,571
Goodwill		11,328
Total assets acquired	$	27,809
Accounts payable and accrued liabilities	$	5,059
Net assets acquired	$	22,750

Pro forma combined operating results for the years ended December 31, 2007 and 2006 (adjusted to reflect the results of operations of WOSEA prior to its acquisition) are not provided because the pre-acquisition results related to WOSEA were not material to the historical results of the Company.

2006

Fraser Diving International Ltd.

In July 2006, we acquired the business of Singapore-based Fraser Diving International Ltd. (“Fraser”) for an aggregate purchase price of approximately $29.3 million, subject to post-closing adjustments, and the assumption of $2.2 million of liabilities. Fraser owned six portable saturation diving systems and 15 surface diving systems that operate primarily in Southeast Asia, the Middle East, Australia and the Mediterranean. Included in the purchase price is a payment of $2.5 million made in December 2005 to Fraser for the purchase of one of the portable saturation diving systems. The acquisition was accounted for as a business combination with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair values. The final valuation of net assets was completed in the second quarter of 2007. The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at the date of acquisition (in thousands):

Cash and cash equivalents	$	2,332
Accounts receivable		1,817
Prepaid expenses and deposits		691

Portable saturation diving systems and surface diving systems		23,685
Diving support equipment, support facilities and other equipment		3,004
Total assets acquired	$	31,529
Accounts payable and accrued liabilities	$	2,243
Net assets acquired	$	29,286

The results of Fraser have been included in the accompanying consolidated statements of operations in our Shelf Contracting segment since the date of purchase. Pro forma combined operating results for the year ended December 31, 2006 (adjusted to reflect the results of operations of Fraser prior to its acquisition) are not provided because the pre-acquisition results related to Fraser were not material to the historical results of the Company.

Pro forma combined operating results of the Company and the Horizon and Remington acquisitions for the years ended December 31, 2007 and 2006 were presented as if the acquisitions had been completed as of January 1, 2006. The unaudited pro forma combined results were as follows (in thousands, except per share data):

	Year Ended December 31,	
	2007	2006
Net revenues	$ 2,150,041	$ 2,040,600
Income before income taxes (1)	496,639	673,354
Net income (1)	298,195	369,889
Net income applicable to common shareholders (1)	294,479	366,531
Earnings per common share (1):		
Basic	$ 3.27	$ 4.02
Diluted	$ 3.11	$ 3.84

(1) Includes pre-tax gain of $151.7 million and $223.1 million related to CDI's issuance of stock during the year ended December 31, 2007 and 2006, respectively. The taxes associated with this gain were approximately $53.1 million and $126.6 million, respectively.

Note 7 — Oil and Gas Properties

We follow the successful efforts method of accounting for our interests in oil and gas properties. Under the successful efforts method, the costs of successful wells and leases containing productive reserves are capitalized. Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized. Costs incurred relating to unsuccessful exploratory wells are expensed in the period the drilling is determined to be unsuccessful.

At December 31, 2007, we had certain capitalized exploratory drilling costs associated with ongoing exploration and/or appraisal activities. In the fourth quarter of 2008, we charged the costs associated with the Huey and Castleton exploration wells to dry hole exploration expense,when it became unlikely that we would pursue additional development of these wells. Other capitalized costs may be charged against earnings in future periods if management determines that commercial quantities of hydrocarbons have not been discovered or that future appraisal drilling or development activities are not likely to occur. The following table provides a detail of our capitalized exploratory project costs at December 31, 2008 and 2007 (in thousands):

	2008	2007
Huey	$ —	$ 11,556
Castleton (part of Gunnison)	—	7,071
Wang	1,545	—
Other	560	469
Total	$ 2,105	$ 19,096

The following table reflects net changes in suspended exploratory well costs during the year ended December 31, 2008, 2007 and 2006 (in thousands):

	2008	2007	2006
Beginning balance at January 1,	$ 19,096	$ 49,983	$ 12,014
Additions pending the determination of proved reserves	2,305	213,699	138,679
Reclassifications to proved properties	(463)	(234,277)	(62,375)
Charged to dry hole expense	(18,833)	(10,309)	(38,335)

Ending balance at December 31,	$ 2,105	$ 19,096	$ 49,983

Further, the following table details the components of exploration expense for the years ended December 31, 2008, 2007 and 2006 (in thousands):

	Years Ended December 31,		
	2008	2007	2006
Delay rental and geological and geophysical costs	$ 5,223	$ 6,538	$ 4,780
Dry hole expense, including impairment of unproved properties	27,703	20,187	38,335
Total exploration expense	$ 32,926	$ 26,725	$ 43,115

Our oil and gas activities in the United States are regulated by the federal government and require significant third-party involvement, such as refinery processing and pipeline transportation. We record revenue from our offshore properties net of royalties paid to the MMS. Royalty fees paid totaled approximately $66.3 million, $57.1 million and $41.0 million for the years ended December 31, 2008, 2007 and 2006, respectively. In accordance with federal regulations that require operators in the Gulf of Mexico to post an area wide bond of $3 million, the MMS has allowed us to fulfill such bonding requirements through an insurance policy.

In July 2006 we sold our interest in Atwater Block 63 (Telemark) and surrounding fields for $15 million in cash and we also retained a reservation of an overriding royalty interest in the Telemark development. We recorded a gain of $2.2 million in 2006 related to this sale.

In August 2006, we acquired a 100% working interest in the Typhoon oil field (Green Canyon Blocks 236/237), the Boris oil field (Green Canyon Block 282) and the Little Burn oil field (Green Canyon Block 238) for assumption of certain decommissioning liabilities. We have received suspension of production ("SOP") approval from the MMS. We will also have farm-in rights on five near-by blocks where three prospects have been identified in the Typhoon mini-basin. Following the acquisition of the Typhoon field and MMS approval, we renamed the field Phoenix. We expect to deploy a minimal floating production system in 2010 in the Phoenix field.

In December 2006, we acquired a 100% working interest in the Camelot gas field in the North Sea in exchange for the assumption of certain decommissioning liabilities estimated at approximately $7.6 million. In June 2007, we sold a 50% working interest in this property for approximately $1.8 million and the assumption by the purchaser of 50% of the decommissioning liability of approximately $4.0 million. We recognized a gain of approximately $1.6 million as a result of this sale.

In 2007, we incurred $25.1 million of plug and abandonment overruns related to hurricanes Katrina and Rita, partially offset by insurance recoveries of $4.0 million. In addition, we increased our abandonment liability at December 31, 2007 for work yet to be done for certain properties damaged by the hurricanes totaling $9.6 million, partially offset by estimated insurance recoveries of $4.9 million. Further, in 2006, we expensed inspection and repair costs related to damages sustained by Hurricanes Katrina and Rita for our oil and gas properties totaling approximately $16.8 million, partially offset by $9.7 million of insurance recoveries received. In 2005, we expensed approximately $7.1 million of inspection and repair costs as a result of damages caused by these hurricanes.

On September 30, 2007, we sold a 30% working interest in the Phoenix, Boris oilfield and the Little Burn oilfield (Green Canyon Block 238) to Sojitz GOM Deepwater, Inc. ("Sojitz"), a wholly owned subsidiary of Sojitz Corporation, for a cash payment of $40 million and the proportionate recovery of all past and future capital expenditures related to the re-development of the fields, excluding the conversion of the Helix Producer I, which we plan to use as a redeployable floating production unit ("FPU"). Proceeds of $51.2 million from the sale were collected in October 2007. Sojitz will also pay its proportionate share of the operating costs including fees payable for the use of the FPU. A gain of approximately $40.4 million was recorded in 2007.

Also in 2007, we recorded impairment expense of approximately $64.1 million related to our proved oil and gas properties primarily as a result of downward reserve revisions and weak end of life well performance in some of our domestic properties. In addition, we recorded approximately $9.9 million of impairment expense related to our unproved properties primarily due to management's assessment that exploration activities would not commence prior to the respective lease expiration dates. Further, we expensed approximately $5.9 million of dry hole exploratory costs in fourth quarter related to our South Marsh Island 123 #1 well drilled in 2007 due to management's decision not to execute previous development plans prior to the lease expiring. Lastly, 2007 depletion was impacted by certain producing properties that experienced significant proved reserve declines, thus causing a significant increase in the depletion rate for these properties.

In March and April 2008, we sold a total 30% working interest in the Bushwood discoveries (Garden Banks Blocks 463, 506 and 507) and other Outer Continental Shelf oil and gas properties (East Cameron Blocks 371 and 381), in two separate transactions 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 based upon certain field production milestones. The new co-owners will also pay their pro rata share of all future capital expenditures related to the exploration and development of these fields. Decommissioning liabilities will be shared on a pro rata share basis between the new co-owners and us. Proceeds from the sale of these properties were used to pay down 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 investor. 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 amounts under our outstanding loans in May 2008. Included in the cost basis of the Onshore Properties was an $8.1 million allocation of goodwill from our Oil and Gas segment.

As a result of our unsuccessful development well in January 2008 on Devil's Island (Garden Banks Block 344), we recognized impairment expense of $14.6 million in 2008 related to the cost incurred subsequent to December 31, 2007. The $20.9 million of the costs incurred related to this well through December 31, 2007, were charged to earnings in 2007.

In September 2008, we sustained damage to certain of our oil and gas production facilities from Hurricanes Gustav and Ike. While we sustained some damage to our own production facilities from Hurricane Ike, the larger issue in terms of production recovery involves damage to third party pipelines and onshore processing facilities. The timing of when these facilities reestablished operations was not subject to our control and in certain cases some of these third party facilities remain out of service at the time of this filing. We carry comprehensive insurance on all of our operated and non-operated producing and non-producing properties, which is subject to approximately $6 million of aggregate deductibles. We met our aggregate deductable in September 2008. We record our hurricane-related costs as incurred. Insurance reimbursements will be recorded when the realization of the claim for recovery of a loss is deemed probable. In 2008, we incurred hurricane-related repair cost totaling $22.8 million. As of December 31, 2008, the aggregate amount of hurricane reimbursements associated with Hurricanes Gustav and Ike totaled $12.1 million, with $4.3 million of this amount reflected as a reimbursement in the accompanying statements of operations and the remainder as a reduction of our property and equipment.

Note 8 — Details of Certain Accounts (in thousands)

Other current assets consisted of the following as of December 31, 2008 and 2007:

	2008	2007
Other receivables	$ 23,497	$ 6,733
Prepaid insurance	18,327	21,133
Other prepaids	24,241	14,922
Spare parts inventory	32,195	29,925
Current deferred tax assets	4,291	13,810
Hedging assets	26,800	1,424
Insurance claims to be reimbursed	7,880	10,173
Income tax receivable	25,308	8,838
Gas imbalance	7,550	6,654
Other	4,941	11,970
	$ 175,030	$ 125,582

Other assets, net, consisted of the following as of December 31, 2008 and 2007:

	2008	2007
Restricted cash	$ 35,402	$ 34,788
Deposits	1,890	8,417
Deferred drydock costs, net	38,620	47,964
Deferred financing costs	36,703	39,290

Intangible assets with finite lives		12,328		22,216
Intangible asset with indefinite life		3,214		7,022
Contracts receivable		—		14,635
Other		8,779		2,877
	$	136,936	$	177,209

Accrued liabilities consisted of the following as of December 31, 2008 and 2007:

	2008	2007
Accrued payroll and related benefits	$ 46,812	$ 50,389
Royalties payable	10,265	21,974
Current decommissioning liability	31,116	23,829
Unearned revenue	9,353	1,140
Billings in excess of costs	13,256	20,403
Insurance claims to be reimbursed	7,880	14,173
Accrued interest	34,299	7,090
Accrued severance (1)	1,953	14,786
Deposits	25,542	13,600
Hedging liability	7,687	10,308
Other	44,860	43,674
	$ 233,023	$ 221,366

(1) Related to payments to be made to former Horizon personnel as a result of the acquisition by CDI.

Note 9 — Equity Investments

In June 2002, we formed Deepwater Gateway with Enterprise Products Partners, L.P., in which we each own a 50% interest, to design, construct, install, own and operate a tension leg platform "TLP" production hub in deepwater of the Gulf of Mexico. Deepwater Gateway primarily services the Marco Polo field, which is owned and operated by Anadarko Petroleum Corporation. Our share of the Deepwater Gateway construction costs was approximately $120 million and our investment totaled $106.3 million and $112.8 million as of December 31, 2008 and 2007, respectively, and was included in our Production Facilities segment. The investment balance at December 31, 2008 and 2007 included approximately $1.6 million and $1.7 million, respectively, of capitalized interest and insurance paid by us.

In December 2004, we acquired a 20% interest in Independence Hub, an affiliate of Enterprise. Independence Hub owns the Independence Hub platform located in Mississippi Canyon Block 920 in a water depth of 8,000 feet. The platform reached mechanical completion in May 2007. As a result, our performance guaranty related to Independence Hub terminated in May 2007 with no further obligations. First production began in July 2007. Our investment in Independence Hub was $90.2 million and $95.7 million as of December 31, 2008 and 2007, respectively (including capitalized interest of $5.9 million and $6.2 million at December 31, 2008 and 2007, respectively), and was included in our Production Facilities segment.

During 2007, CDI determined that there was an other than temporary impairment of its equity investment in OTSL and the full value of its investment was impaired. CDI recorded equity losses in OTSL of $10.8 million, inclusive of the impairment charge, and $0.5 million for the fiscal years ended December 31, 2007, and 2006, respectively. CDI sold its equity interest in OTSL to a third party in January 2009 for $0.4 million.

We made the following contributions to our equity investments during the years ended December 31, 2008, 2007 and 2006 (in thousands):

Year Ended December 31,

	2008	2007	2006
Independence Hub	$ —	$ 12,475	$ 27,578
Other	846	4,984	—
Total	$ 846	$ 17,459	$ 27,578

We received the following distributions from our equity investments during the years ended December 31, 2008, 2007 and 2006 (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Deepwater Gateway	$ 23,500	$ 27,000	$ 16,250
Independence Hub	25,000	10,800	—
Total	$ 48,500	$ 37,800	$ 16,250

Note 10 — Consolidated Variable Interest Entities

In October 2006, we partnered with Kommandor RØMØ, a Danish corporation to form Kommandor LLC, a Delaware limited liability company, whose purpose is to convert a ferry vessel into a dynamically-positioned construction services vessel. Upon completion of the conversion, this vessel will be leased to us under a bareboat charter and we plan to perform additional capital modifications in order to utilize the vessel for future use as a floating production system servicing the Deepwater Gulf of Mexico, with initial service being provided for the Phoenix field, in which we hold an approximate 70% working interest. The initial investment for our 50% interest in Kommandor LLC was $15 million. Further, we provided an initial loan facility of up to $84.7 million at December 31, 2008 and Kommandor RØMØ loaned $5 million to the entity for purposes of completing the conversion. The vessel is expected to be completed in two phases. The first phase, the initial conversion, is expected to be completed in second quarter 2009 and its total cost is estimated to range between $150 million and $160 million. The second phase, our capital modifications, is expected to be completed by early 2010. Estimated costs for the capital modifications to the vessel in the second phase, in which we expect to fund 100%, will range between $195 and $205 million .

The operating agreement with Kommandor RØMØ, provides that for a period of two months immediately following the fifth anniversary of the completion of the initial conversion, we may purchase Kommandor RØMØ's membership interest at a value specified in the agreement ("Helix Option Period"). In addition, for a period of two months starting from 30 days after the Helix Option Period, Kommandor RØMØ can require us to purchase its share of the company at a value specified in the operating agreement. We estimate the cash outlay to Kommandor RØMØ for its interest in Kommandor LLC at the time the put or call is exercised to be approximately $28 million.

Kommandor LLC qualifies as a VIE under FIN 46 and we determined that we are the primary beneficiary and, thus, we have consolidated the financial results of Kommandor LLC as of December 31, 2008 and 2007. The results of Kommandor LLC are included in our Production Facilities segment. Kommandor LLC has been a development stage enterprise since its inception in October 2006.

Note 11 — Long-Term Debt

Senior Unsecured Notes

On December 21, 2007, we issued $550 million of 9.5% Senior Unsecured Notes due 2016 ("Senior Unsecured Notes"). The Senior Unsecured Notes are fully and unconditionally guaranteed by substantially all of our existing restricted domestic subsidiaries, except for CDI and its subsidiaries and Cal Dive I-Title XI, Inc. In addition, any future guarantee of our or any of our restricted subsidiaries' indebtedness is also required to guarantee the Senior Unsecured Notes. CDI, the subsidiaries of CDI, and our foreign subsidiaries are not guarantors of the Senior Unsecured Notes. We used the proceeds from the Senior Unsecured Notes to repay outstanding indebtedness under our senior secured credit facilities (see below).

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

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

Included in the Senior Unsecured Notes indenture are terms, conditions and covenants that are customary for this type of offering. The covenants include limitations on our and our subsidiaries' ability to incur additional indebtedness, pay dividends, repurchase our common stock, and sell or transfer assets. As of December 31, 2008, we were in compliance with these covenants.

The Senior Unsecured Notes may be redeemed prior to the stated maturity under the following circumstances:

- After January 15, 2012, we may redeem all or a portion of the Senior Unsecured Notes, on not less than 30 days' nor more than 60 days' prior notice, at the redemption prices (expressed as percentages of the principal amount) set forth below, plus accrued and unpaid interest, if any, thereon, to the applicable redemption date.

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

- In addition, at any time prior to January 15, 2011, we may use the net proceeds from any equity offering to redeem up to an aggregate of 35% of the total principal amount of Senior Unsecured Notes at a redemption price equal to 109.5% of the cumulative principal amount of the Senior Unsecured Notes redeemed, plus accrued and unpaid interest, if any, to the redemption date, provided that this redemption provision shall not be applicable with respect to any transaction that results in a change of control of the Company. At least 65% of the aggregate principal amount of Senior Unsecured Notes must remain outstanding immediately after the occurrence of such redemption.

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

Senior Credit Facilities

On July 3, 2006, we entered into a credit agreement (the "Senior Credit Facilities") under which we borrowed $835 million in a term loan (the "Term Loan") and were initially able to borrow up to $300 million (the "Revolving Loans") under a revolving credit facility (the "Revolving Credit Facility"). The proceeds from the Term Loan were used to fund the cash portion of the Remington acquisition. This facility was subsequently amended in November 2007, and as part of that amendment, an accordion feature was added that allows for increases in the Revolving Credit Facility up to an additional $150 million, subject to availability of borrowing capacity provided by new or existing lenders. On May 29, 2008, we completed a $120 million increase in the Revolving Credit Facility utilizing this accordion feature. Total borrowing capacity under the Revolving Credit Facility now totals $420 million. The full amount of the Revolving Credit Facility may be used for issuances of letters of credit.

The Term Loan and the Revolving Loans (together, the "Loans") bear interest either to the Bank of America's base rate or to LIBOR, at our election. Our current election is to bear interest based on LIBOR. The Term Loan or portions thereof bear interest at one, two, three or six-month LIBOR rate at our election plus an applicable margin of 2.00%. Our interest rate for year ended December 31, 2008 and 2007 was approximately 6.0% and 7.1%, respectively (including the effects of our interest rate swaps). The Revolving Loans or portions thereof bear interest based on one, two, three or six-month LIBOR rates or on Base Rate at our election plus an applicable margin ranging from 1.00% to 2.25% on Libor loans or 0% to 1.25% on Base Rate loans. Margins on the Revolving Loans will fluctuate in relation to our consolidated leverage ratio as provided under the Credit Agreement.

The Term Loan matures on July 1, 2013 and is subject to quarterly scheduled principal payments. As a result of a $400 million prepayment made in December 2007, the scheduled quarterly principal payment was reduced from $2.1 million to $1.1 million. The Revolving Loans mature on July 1, 2011. We may elect to prepay amounts outstanding under the Term Loan without prepayment penalty, but may not reborrow any amounts prepaid. We may prepay amounts outstanding under the Revolving Loans without prepayment penalty, and may reborrow amounts prepaid prior to maturity. We had $44.4 million ($59.4 million as of February 27, 2009) and $240.8 million available under the Revolving Loans (including unsecured letters of credit of $26.1 million and $41.2 million) at December 31, 2008 and 2007, respectively. In addition, upon the occurrence of certain dispositions or the issuance or incurrence of certain types of indebtedness, we may be required to prepay a portion of the Term Loan equal to the amount of proceeds received from such occurrences. Such prepayments will be applied first to the Term Loan, and any remaining excess will then be applied to the Revolving Loans.

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

If we or any of our subsidiaries do not pay any amounts owed to the Lenders under the Loan Documents when due, breach any other covenant to the Lenders or fail to pay other debt above a stated threshold, in each case, subject to applicable cure periods, then the Lenders have the right to stop making advances to us and to declare the Loans immediately due. The Credit Agreement includes other events of default that are customary for this type of transaction. As of December 31, 2008, we were in compliance with all debt covenants.

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

As the rates for our Term Loan are subject to market influences and will vary over the term of the credit agreement, we entered into various cash flow hedging interest rate swaps to stabilize cash flows relating to a portion of our interest payments for our Term Loan. The interest rate swaps were effective October 3, 2006, and qualified for hedge accounting. On December 21, 2007, a prepayment made to a hedged portion of our Term Loan brought the balance of that portion below the amount hedged by interest rate swaps. As a result, the hedge instruments became ineffective and no longer qualify for hedge accounting as of that date. The future changes in the fair value of these contracts will impact our future earnings as they occur.

Cal Dive International, Inc. Credit Facility

In December 2007, CDI replaced its five-year $250 million revolving credit facility by entering into a secured credit facility with a bank group led by Bank of America, N.A., which also serves as administrative agent, consisting of a $375 million term loan and a $300 million revolving credit facility. Both the term loan and the revolving loans mature on December 11, 2012. Loans under this CDI facility are non-recourse to us. The term loan and the revolving loans may consist of loans bearing interest in relation to the Federal Funds Rate or to Bank of America’s base rate, known as Base Rate Loans, and loans bearing interest in relation to a LIBOR rate, known as Eurodollar Rate Loans, in each case plus an applicable margin. The margins on the revolving loans range from 0.75% to 1.50% on Base Rate Loans and 1.75% to 2.50% on Eurodollar Rate Loans. The margins on the term loan are 1.25% on Base Rate Loans and 2.25% on Eurodollar Rate Loans. If a default exists, the interest rates may be increased.

The credit agreement and the other documents entered into in connection with the credit agreement include terms and conditions, including covenants, which we consider customary for this type of transaction. The covenants include restrictions on CDI and CDI’s subsidiaries’ ability to grant liens, incur indebtedness, make investments, merge or consolidate, sell or transfer assets and pay dividends. In addition, the credit agreement obligates CDI to meet minimum financial requirements specified in the agreement. The credit facility is secured by vessel mortgages on all of CDI’s vessels (except for the Sea Horizon), a pledge of all of the stock of all of CDI’s domestic subsidiaries and 66% of the stock of two of CDI’s foreign subsidiaries, and a security interest in, among other things, all of CDI’s equipment, inventory, accounts and general intangible assets. At December 31, 2008, CDI was in compliance with all debt covenants.

On December 11, 2007, CDI borrowed $375 million under their term loan and used those proceeds to fund the cash portion of its merger consideration in connection with CDI’s acquisition of Horizon and to retire Horizon’s existing debt. The term loan requires quarterly principal payments of $20 million beginning June 20, 2008. For the years ended December 31, 2008 and 2007 there was $292.5 million and $273.3 million, respectively, available under the revolving credit facility (including $7.5 million and $26.7 million, respectively, of unsecured letters of credit). CDI expects to use the remaining availability under the revolving credit facility for its working capital and other general corporate purposes.

On January 26, 2009, CDI borrowed $100 million under its revolving credit facility to purchase from us shares of its common stock representing approximately 13.6 million shares at $6.34 per share As of February 20, 2009, CDI has $186.7 million available under the revolving credit facility. CDI expects to use the remaining availability under its revolving credit facility for working capital and other general corporate purposes.

Convertible Senior Notes

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

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

- during any fiscal quarter (beginning with the quarter ended March 31, 2005) if the closing sale price of our common stock for at least 20 trading days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter exceeds 120% of the conversion price on that 30th trading day (i.e., $38.56 per share);

- upon the occurrence of specified corporate transactions; or

- if we have called the Convertible Senior Notes for redemption and the redemption has not yet occurred.

To the extent we do not have alternative long-term financing secured to cover such conversion notice, the Convertible Senior Notes would be classified as a current liability in the accompanying balance sheet.

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

- cash equal to the lesser of $1,000 and the conversion value; and

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

The conversion value means the product of (1) the conversion rate in effect (plus any applicable additional shares resulting from an adjustment to the conversion rate) or, if the Convertible Senior Notes are converted during a registration default, 103% of such conversion rate (and any such additional shares), and (2) the average of the last reported sale prices of our common stock for the trading days during the cash settlement period. At December 31, 2008, the conversion trigger was not met.

Our weighted average share price for 2008 was below the conversion price of $32.14 per share. The maximum number of shares of common stock which may be issued upon conversion of the Convertible Senior Notes is 13,303,770. We registered the 13,303,770 shares of common stock that may be issued upon conversion of the Convertible Senior Notes as well as an indeterminate number of shares of common stock issuable upon conversion of the Convertible Senior Notes by means of an antidilution adjustment of the conversion price pursuant to the terms of the Convertible Senior Notes. Proceeds from the offering were used to make a capital contribution of $72 million, made in March 2005, to Deepwater Gateway to enable it to repay its term loan, and strategic acquisitions in 2005 and for general corporate purposes.

MARAD Debt

At December 31, 2008 and 2007, $123.4 million and $127.5 million, respectively, was outstanding on our long-term financing used for construction of the Q4000. This U.S. Government guaranteed financing is pursuant to Title XI of the Merchant Marine Act of 1936 which is administered by the Maritime Administration ("MARAD Debt"). The MARAD Debt is payable in equal semi-annual installments which began in August 2002 and matures 25 years from such date. The MARAD Debt is collateralized by the Q4000, with us guaranteeing 50% of the debt, and initially bore interest at a floating rate which approximated AAA Commercial Paper yields plus 20 basis points. As provided for in the existing MARAD Debt agreements, in September 2005, we fixed the interest rate on the debt through the issuance of a 4.93% fixed-rate note with the same maturity date (February 2027). In accordance with the MARAD Debt agreements, we are required to comply with certain covenants and restrictions, including the maintenance of minimum net worth, working capital and debt-to-equity requirements. At December 31, 2008, we are in compliance with these debt covenants.

Other

We paid financing costs associated with our issuance of debt totaling $2.2 million in 2008 and $17.2 million in 2007. Deferred financing costs of $36.7 million and $39.3 million at December 31, 2008 and 2007, respectively, are included within the caption “Other Assets, Net” in the accompanying consolidated balance sheets and are being amortized over the life of the respective agreements. In December 2007, as a result of prepaying $400 million of borrowing under our Term Loan, we charged $3.5 million to interest expense representing the proportionate share of the deferred financing cost related to the prepaid amount of the Term Loan.

Scheduled maturities of long-term debt and capital lease obligations outstanding as of December 31, 2008 were as follows (in thousands):

	Helix Term Loan	Helix Revolving Loans	CDI Term Loan	Senior Unsecured Notes	Convertible Senior Notes (1)	MARAD Debt	Loan Note (2)	Total
Less than one year	$ 4,326	$ —	$ 80,000	$ —	$ —	$ 4,214	$ 5,000	$ 93,540
One to two years	4,326	—	80,000	—	—	4,424	—	88,750
Two to three years	4,326	349,500	80,000	—	—	4,645	—	438,471
Three to four years	4,326	—	75,000	—	—	4,877	—	84,203
Four to five years	401,789	—	—	—	—	5,120	—	406,909
Over five years	—	—	—	550,000	300,000	100,169	—	950,169
Long-term debt	419,093	349,500	315,000	550,000	300,000	123,449	5,000	2,062,042
Current maturities	(4,326)	—	(80,000)	—	—	(4,214)	(5,000)	(93,540)
Long-term debt, less current maturities	$ 414,767	$ 349,500	$ 235,000	$ 550,000	$ 300,000	$ 119,235	$ —	$ 1,968,502

(1) Beginning in December 2012, we may at our option, repurchase notes or the holders may require repurchase of notes.

(2) Represents the $5 million loan provided by Kommandor RØMØ to Kommandor LLC as of December 31, 2008.

We had unsecured letters of credit outstanding at December 31, 2008 totaling approximately $33.7 million. These letters of credit primarily guarantee various contract bidding and insurance activities. The following table details our interest expense and capitalized interest for the years ended December 31, 2008, 2007 and 2006 (in thousands):

	Year Ended December 31, 2008	2007	2006
Interest expense	$ 129,170	$ 100,397	$ 51,913
Interest income	(2,531)	(9,539)	(6,259)
Capitalized interest	(42,125)	(31,790)	(10,609)

Interest expense, net	$ 84,514	$ 59,068	$ 35,045

Note 12 — Income Taxes

We and our subsidiaries, including acquired companies from their respective dates of acquisition, file a consolidated U.S. federal income tax return. At December 13, 2006, CDI was separated from our tax consolidated group as a result of its initial public offering. As a result, we are required to accrue income tax expense on our share of CDI's net income after the initial public offering in all periods where we consolidate their operations. The deconsolidation of CDI's net income after its initial public offering did not have a material impact on our consolidated results of operations; however, because of our inability to recover our tax basis in CDI tax free, a long term deferred tax liability is provided for any incremental tax increases to the book over tax basis.

We conduct our international operations in a number of locations that have varying laws and regulations with regard to taxes. Management believes that adequate provisions have been made for all taxes that will ultimately be payable. Income taxes have been provided based on the US statutory rate of 35% adjusted for items which are allowed as deductions for federal income tax reporting purposes, but not for book purposes. The primary differences between the statutory rate and our effective rate were as follows:

	Year Ended December 31,		
	2008	2007	2006
Statutory rate	35.0%	35.0%	35.0%
Gain on subsidiary equity transaction	—	—	8.0
Foreign provision	2.4	(1.4)	(0.2)
Percentage depletion in excess of basis	—	—	(0.1)
IRC Section 199 deduction	0.7	(0.2)	(0.2)
CDI Equity Pick up in excess of tax basis	(4.2)	—	—
Nondeductible Goodwill Impairment	(50.4)	—	—
Other	(1.7)	(0.1)	—
Effective rate	(18.2)%	33.3%	42.5%

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

	Year Ended December 31,		
	2008	2007	2006
Current	$ 93,051	$ 47,970	$ 199,921
Deferred	(3,074)	126,958	57,235
	$ 89,977	$ 174,928	$ 257,156

	Year Ended December 31,		
	2008	2007	2006
Domestic	$ 45,517	$ 149,793	$ 247,588
Foreign	44,460	25,135	9,568
	$ 89,977	$ 174,928	$ 257,156

Deferred income taxes result from the effect of transactions that are recognized in different periods for financial and tax reporting purposes. The nature of these differences and the income tax effect of each as of December 31, 2008 and 2007 are as follows (in thousands):

	2008	2007
Deferred tax liabilities:		
Depreciation and Depletion	$ 639,508	$ 581,178
Subsidiary book basis in excess of tax	71,048	50,339
Equity investments in production facilities	41,839	35,288
Prepaid and other	45,045	59,237
Total deferred tax liabilities	$ 797,440	$ 726,042
Deferred tax assets:		
Net operating loss carryforward	$ (3,533)	$ (19,933)
Decommissioning liabilities	(150,337)	(65,685)
Reserves, accrued liabilities and other	(46,714)	(31,693)
Total deferred tax assets	(200,584)	(117,311)
Valuation allowance	3,317	2,967
Net deferred tax liability	$ 600,173	$ 611,698

	2008	2007
Deferred income tax is presented as:		
Current deferred tax asset	$ (4,291)	$ (13,810)
Non current deferred tax liability	604,464	625,508
Net deferred tax liability	$ 600,173	$ 611,698

As a result of the Remington acquisition on July 1, 2006, a deferred tax asset was recorded as a part of the purchase price allocation to reflect the availability of approximately $65.2 million of net operating loss carryforwards as of the acquisition date. As a result of Helix's federal taxable income position during 2006 and 2008, we were able to utilize all of the $65.2 million of the net operating loss carryforwards at December 31, 2008. At December 31, 2007 Helix had a $28.0 million net operating loss, $1.3 million alternative minimum credit, $8.3 million foreign tax credit and $1 million general business credit, which were fully utilized in 2008. At December 31, 2008, CDI had $10.1 million in net operating loss carryforwards, which begin to expire in 2016.

We consider the undistributed earnings of our principal non-U.S. subsidiaries to be permanently reinvested. At December 31, 2008 and 2007, our principal non-U.S. subsidiaries had accumulated earnings and profits of approximately $132.8 million and $60.0 million, respectively. We have not provided deferred U.S. income tax on the accumulated earnings and profits. Alternatively, as a result of our inability to recover our tax basis in CDI tax free, we have provided a deferred tax liability on the incremental increases to the book over tax basis.

We adopted the provisions of FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes ("FIN 48") on January 1, 2007. The impact of the adoption of FIN 48 was immaterial to our financial position, results of operations and cash flows. During 2008, we recorded a $5.4 million long term liability for uncertain tax benefits, interest and penalty. We recorded a $5.0 million increase to goodwill as part of the Horizon purchase price allocation and $0.4 million was recorded as income tax expense. We account for tax related interest in interest expense and tax penalties in operating expenses as allowed under FIN 48. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows (in thousands):

	Liability for Unrecognized Tax Benefits	
Gross unrecognized tax benefits at January 1, 2008	$	640
Increases in tax positions for current years		2,643
Increases in tax positions for prior years		1,900
Gross unrecognized tax benefits at December 31, 2008	$	5,183

The total amount of tax benefits that, if recognized, would affect the effective tax rate was $5.2 million at December 31, 2008. At December 31, 2008, CDI accrued $3.5 million of interest and penalties related to unrecognized tax benefits.

We file tax returns in the U.S. and in various state, local and non-U.S. jurisdictions. We anticipate that any potential adjustments to our state, local and non-U.S. jurisdiction tax returns by tax authorities would not have a material impact on our financial position. The tax periods ending December 31, 2002, 2003, 2005, 2006, 2007 and 2008 remain subject to examination by the U.S. Internal Revenue Service ("IRS"). In addition, as we acquired Remington on July 1, 2006 we are exposed to any tax uncertainties related to Remington. For Remington, the tax period ending June 30, 2006 remains subject to examination by the IRS. The 2004 and 2005 tax returns for Remington were examined by the IRS and the examination was concluded with no adjustment.

During the fourth quarter of 2006, Horizon received a tax assessment from the SAT, the Mexican taxing authority, for approximately $23 million related to fiscal 2001, including penalties, interest and monetary correction. The SAT's assessment claims unpaid taxes related to services performed among the Horizon subsidiaries that CDI acquired at the time it acquired Horizon. CDI believes under the Mexico and United States double taxation treaty that these services are not taxable and that the tax assessment itself is invalid. On February 14, 2008, CDI received notice from the SAT upholding the original assessment. On April 21, 2008, CDI filed a petition in Mexico tax court disputing the assessment. We believe that CDI's position is supported by law and CDI intends to vigorously defend its position. However, the ultimate outcome of this litigation and CDI's potential liability from this assessment, if any, cannot be determined at this time. Nonetheless, an unfavorable outcome with respect to the Mexico tax assessment could have a material adverse effect on our financial position and results of operations. Horizon's 2002 through 2007 tax years remain subject to examination by the appropriate governmental agencies for Mexico tax purposes, with 2002 through 2004 currently under audit.

In December 2006, we entered into the Tax Matters Agreement with CDI in connection with the CDI initial public offering. The following is a summary of the material terms of the Tax Matters Agreement:

- Liability for Taxes. Each party has agreed to indemnify the other in respect of all taxes for which it is responsible under the Tax Matters Agreement. We are generally responsible for all federal, state, local and foreign income taxes that are imposed on or are attributable to CDI or any of its subsidiaries for all tax periods (or portions thereof) ending on or before CDI's initial public offering. CDI is generally responsible for all federal, state, local and foreign income taxes that are imposed on or are attributable to CDI or any of its subsidiaries for all tax periods (or portions thereof) beginning after its initial public offering. CDI is also responsible for all taxes other than income taxes imposed on or attributable to CDI or any of its subsidiaries for all tax periods.

- Tax Benefit Payments. As a result of certain taxable income recognition by us in conjunction with the CDI initial public offering, CDI will become entitled to certain tax benefits that are expected to be realized by CDI in the ordinary course of its business and otherwise would not have been available to CDI. These benefits are generally attributable to increased tax deductions for amortization of tangible and intangible assets and to increased tax basis in nonamortizable assets. Under the Tax Matters

Agreement, for a period of up to ten years, CDI will be required to make annual payments to us equal to 90% of the amount of taxes which CDI saves for each tax period as a result of these increased tax benefits. The timing of CDI's payments to us under the Tax Matters Agreement will be determined with reference to when CDI actually realizes the projected tax savings. This timing will depend upon, among other things, the amount of their taxable income and the timing at which certain assets are sold or disposed.

• Preparation and Filing of Tax Returns. We will prepare and file all income tax returns that include CDI or any of its subsidiaries if we are responsible for any portion of the taxes reported on such tax returns. The Tax Matters Agreement also provides that we will have the sole authority to respond to and conduct all tax proceedings (including tax audits) relating to such income tax returns.

For the year ended December 31, 2008, this agreement did not have a material impact on our consolidated results of operations.

Note 13 — Convertible Preferred Stock

In January 2003, we completed the private placement of $25 million of a newly designated class of cumulative convertible stock (Series A-1 Cumulative Convertible Stock, par value $0.01 per share) convertible into 1,666,668 shares or our common stock at $15 per share. The preferred stock was issued to a private investment firm, Fletcher International, Ltd.("Fletcher"). Subsequently on June 2004, Fletcher exercised an existing right to purchase an additional $30 million of cumulative convertible preferred stock (Series A-2 Cumulative Convertible Preferred Stock, par value $0.01 per share) convertible into 1,964,058 shares of our common stock at $15.27 per share. Pursuant to the agreement governing the preferred stock (the "Fletcher Agreement"), Fletcher was entitled to convert its investment in the preferred shares at any time, and to redeem its investment in the preferred shares at any time after December 31, 2004. In January 2009, Fletcher issued a redemption notice with respect to all of the Series A-2 Cumulative Convertible Preferred Stock, and, pursuant to such redemption, we issued and delivered 5,938,776 shares of our common stock to Fletcher. We will reduce net income applicable to common shareholders by an approximate $29.3 million non-cash dividend that will be reflected in our first quarter of 2009 results. This non-cash dividend reflects the value associated with the additional 3,974,718 shares delivered over the original 1,964,058 shares that were contractually required to be issued upon conversion.

The Fletcher Agreement provides that if the volume weighted average price of our common stock on any date is less than a certain minimum price ($2.767), then our right to pay dividends in our common stock is extinguished, and we must deliver a notice to Fletcher that either (1) the conversion price will be reset to such minimum price (in which case Fletcher shall have no further right to cause the redemption of the preferred stock), or (2) in the event Fletcher exercises its redemption rights, we will satisfy our redemption obligations either in cash, or a combination of cash and common stock subject to a maximum number of shares (14,973,814) that can be delivered to Fletcher under the Fletcher Agreement. As a result of the redemption that occurred in January, the maximum number of shares available for redemption of the Series A-1 Cumulative Convertible Stock is 9,035,038. On February 25, 2009 the volume weighted average price of our common stock was below the minimum price, and, on February 27, 2009 we provided notice to Fletcher that with respect to the Series A-1 Cumulative Convertible Preferred Stock the conversion price is reset to $2.767 as of that date and that Fletcher shall have no further rights to redeem the shares, and we have no further right to pay dividends in common stock. As a result of Fletcher's redemption in January 2009, and the reset of the conversion price, Fletcher would receive an aggregate of 9,035,038 shares in future conversion(s) into our common stock. In the event we elect to settle any future conversion in cash, Fletcher would receive cash in an amount approximately equal to the value of the shares it would receive upon a conversion, which could be substantially greater than the original face amount of the Series A-1 Cumulative Convertible Preferred Stock. Under the existing terms of our Senior Credit Facilities (Note 11) we are not permitted to deliver cash to the holder upon a conversion or redemption of the Convertible Preferred Stock.

The preferred stock has a minimum annual dividend rate of 4%, subject to adjustment, payable quarterly in cash. The dividend rate for the years ended December 31, 2008, 2007 and 2006 was 4% (calculated rate was 3.7%, below the 4% minimum), 6.4% and 6.9%, respectively. At the time these dividends were paid we had the option to pay them in our common stock; we paid them in cash.

The proceeds received from the sales of this stock, net of transaction costs, have been classified outside of shareholders' equity on the balance sheet below total liabilities. Prior to the conversion, common shares issuable will be assessed for inclusion in the weighted average shares outstanding for our diluted earnings per share using the if converted method based on the lower of our share price at the beginning of the applicable period or the applicable conversion prices ($15.00 and $15.27).

Note 14 — Employee Benefit Plans

Defined Contribution Plan

We sponsor a defined contribution 401(k) retirement plan covering substantially all of our employees. Our contributions are in the form of cash and are determined annually as 50 percent of each employee's contribution up to 5 percent of the employee's salary. Our costs related to this plan totaled $3.0 million, $2.8 million and $2.3 million for the years ended December 31, 2008, 2007 and 2006, respectively. Costs related to the CDI 401(k) retirement plan totaled $2.1 million in 2008, $1.4 million in 2007 and $1.4 million in 2006.

Stock-Based Compensation Plans

We have three stock-based compensation plans: the 1995 Long-Term Incentive Plan, as amended (the "1995 Incentive Plan"), the 2005 Long-Term Incentive Plan (the "2005 Incentive Plan") and the 1998 Employee Stock Purchase Plan (the "ESPP"). In addition, CDI has a stock-based compensation plan, the 2006 Long-Term Incentive Plan (the "CDI Incentive Plan") and an Employee Stock Purchase Plan (the "CDI ESPP") available only to the employees of CDI and its subsidiaries. As of December 31, 2008, there were approximately 2.3 million shares available for grant under our 2005 Incentive Plan.

Upon adoption of the 1995 Incentive Plan in May 1995, a maximum of 10% of the total shares of common stock issued and outstanding were eligible to be granted to key executives and selected employees and non-employee members of the Board of Directors. Following the approval by shareholders of the 2005 Incentive Plan in May 2005, no further grants have been or will be made under the 1995 Plan. The aggregate number of shares that may be granted under the 2005 Incentive Plan is 6,000,000 shares (after adjustment for the December 2005 two-for-one stock split) of which 4,000,000 shares may be granted in the form of restricted stock or restricted stock units and 2,000,000 shares may be granted in the form of stock options. The 1995 and 2005 Incentive Plans and the ESPP are administered by the Compensation Committee of the Board of Directors, which in the case of the 1995 and 2005 Incentive Plans, determines the type of award to be made to each participant, and as set forth in the related award agreement, the terms, conditions and limitations applicable to each award. The committee may grant stock options, restricted stock, restricted stock units, and cash awards. Awards granted to employees under the 1995 and 2005 Incentive Plan typically vest 20% per year over a five-year period (or in the case of certain stock option awards under the 1995 Incentive Plan, 33% per year for a three-year period); if in the form of stock options, have a maximum exercise life of ten years; and, subject to certain exceptions, are not transferable.

We account for our stock-based compensation plans under Statement of Financial Accounting Standards No. 123 (Revised 2004) Share-Based Payments ("SFAS 123R"). We continue to use the Black-Scholes option pricing model for valuing share-based payments relating to stock options and recognize compensation cost on a straight-line basis over the respective vesting period. No forfeitures were estimated for outstanding unvested options and restricted shares as historical forfeitures have been immaterial. We utilize the modified-prospective method of adoption. Under that transition method, compensation cost recognized in 2006 included: (a) compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the grant-date fair value, and (b) compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the grant-date fair value. In addition to the compensation cost recognition requirements, tax deduction benefits for an award in excess of recognized compensation cost is reported as a financing cash flow rather than as an operating cash flow. We did not grant any stock options in 2008, 2007 or 2006.

Stock Options

The options outstanding at December 31, 2008, have exercise prices as follows: 139,000 shares at $8.57; 82,774 shares at $10.92; 30,400 shares at $10.94; 30,000 shares at $11.00; 127,680 shares at $12.18; 52,800 shares at $13.91; and 59,000 shares ranging from $8.14 to $10.59, and a weighted average remaining contractual life of 3.9 years.

Options outstanding are as follows:

	2008		2007		2006	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Options outstanding at beginning of year	736,550	$ 10.55	883,070	$ 10.86	1,717,904	$ 10.91
Exercised	(214,896)	$ 10.28	(141,186)	$ 11.10	(792,394)	$ 11.21
Terminated	—	$ —	(5,334)	$ 10.92	(42,440)	$ 10.96
Options outstanding at end of year	521,654	$ 10.66	736,550	$ 10.55	883,070	$ 10.86
Options exercisable end of year	473,054	$ 10.44	537,514	$ 10.28	515,318	$ 10.34

For the years ended December 31, 2008, 2007 and 2006, $1.1 million (of which $0.6 million of compensation expense was recognized in the first half of 2008 related to the acceleration of unvested options per the separation agreements between the Company and two of our former executive officers), $1.0 million and $1.4 million, respectively, was recognized as compensation expense related to stock options. The aggregate intrinsic value of the stock options exercised in 2008, 2007 and 2006 was approximately $5.9 million, $4.1 million and $21.3 million, respectively. Future compensation cost associated with unvested options at December 31, 2008 and 2007 totaled approximately $0.1 million and $0.8 million, respectively. There was no aggregate intrinsic value of options exercisable at December 31, 2008 as the fair market value at year end was lower than the exercise price of the vested stock optons. The aggregate intrinsic value of options exercisable at December 31, 2007 was approximately $16.8 million. The weighted average vesting period related to nonvested stock options at December 31, 2008 was approximately 0.2 years.

Restricted Shares

We grant restricted shares to members of our board of directors, all executive officers and selected management employees. Compensation cost for each award is the product of grant date market value of each share and the number of shares granted. The following table summarizes information about our restricted shares during the years ended December 31, 2008, 2007 and 2006:

	2008		2007		2006	
	Shares	Grant Date Fair Value (1)	Shares	Grant Date Fair Value (1)	Shares	Grant Date Fair Value (1)
Restricted shares outstanding at beginning of year	1,166,077	$ 32.19	729,212	$ 32.29	384,902	$ 25.59
Granted	702,190	$ 34.01	702,297	$ 31.77	497,450	$ 37.07
Vested	(386,963)	$ 31.19	(236,667)	$ 31.32	(66,865)	$ 24.51
Forfeited	(274,778)	$ 35.40	(28,765)	$ 31.59	(86,275)	$ 36.04
Restricted shares outstanding at end of year	1,206,526	$ 32.84	1,166,077	$ 32.19	729,212	$ 32.29

(1)

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

For the years ended December 31, 2008, 2007 and 2006, $18.5 million (of which $3.6 million was related to the accelerated vesting of restricted shares per the separation agreements between the Company and two of our former executive officers during the first half of 2008), $11.7 million and $6.3 million, respectively, was recognized as compensation expense related to restricted shares. In 2008 and 2007, compensation expense of $4.8 and $2.1 million, respectively, was related to the CDI Incentive Plan. Future compensation cost associated with unvested restricted stock awards at December 31, 2008 and 2007 totaled approximately $53.3 million and $41.8 million, respectively, of which $23.4 million and $13.4 million is related to the CDI Incentive Plan. The weighted average vesting period related to nonvested restricted stock awards at December 31, 2008 was approximately 3.4 years.

In January 2009, we granted executive officers and select management employees 343,368 and 26,506 restricted shares and restricted stock units, respectively, under the 2005 Long-Term Incentive Plan. The shares and units vest 20% per year for a five-year period. The market value of the restricted stock is based on the quoted market price of the common stock on the business day prior to the grant date. The market value of the restricted shares was $7.24 per share or $2.5 million. We also granted certain of our outside directors 10,617 restricted shares. The shares vest on January 1, 2011. The market value of the restricted shares was $7.24 per share or $76,867.

Employee Stock Purchase Plan

In May 1998, we adopted a qualified, non-compensatory ESPP, which allows employees to acquire shares of common stock through payroll deductions over a six-month period. The purchase price is equal to 85% of the fair market value of the common stock on either the first or last day of the subscription period, whichever is lower. Purchases under the plan are limited to the lesser of 10% of an employee's base salary or $25,000 of our stock value. Shares of our common stock issued to our employees under the ESPP totaled 98,933 shares in 2008 and 222,984 in 2007. In 2007, we subsequently repurchased approximately the same number of shares of our common stock in the open market at a weighted average price of $35.04 per share and reduced the number of shares of our outstanding common stock. Under this plan 97,598 shares of common stock were purchased in the open market for our employees at a weighted-average share price of $33.12 during 2006. For the years ended December 31, 2008, 2007 and 2006, we recognized $1.8 million, $2.1 and $1.6 million, respectively, of compensation expense related to stock purchased under the ESPP and the CDI ESPP (of which $1.2 million and $0.6 million of expense for the years ended December 31, 2008 and 2007, respectively, was related to the CDI ESPP that became effective in the third quarter of 2007).

In January 2009, we issued 25,393 shares of our common stock to our employees under this plan to satisfy the employee purchase period from July 1, 2008 to December 31, 2008, which increased our common stock outstanding. There are no longer any shares available under this plan.

Stock Compensation Modifications

Under our 1995 Incentive Plan and our 2005 Long-Term Incentive Plan, upon a stock recipient's termination of employment, which is defined as employment with us and any of our majority-owned subsidiaries, any unvested restricted stock and stock options are forfeited immediately, and all unexercised vested options are forfeited as specified under the applicable plan or agreement. Ordinarily, once our beneficial ownership of CDI falls to 50% or below (the "Trigger Date"), the options and unvested shares granted to CDI employees would be forfeited at such date under our current plans. As part of the Employee Matters Agreement between us and CDI, which was executed in December 2006, with respect to any employee who is a Cal Dive employee as of the date of the IPO, we have agreed to extend the life of any vested and unexercised stock options to the earlier of (1) the expiration of the general term of the option or (2) the later of (i) December 31 of the calendar year in which the Trigger Date occurs, or (ii) the 15th day of the third month after the expiration of the 60-day period commencing on the Trigger Date (135 days). To the extent that any such employee would forfeit options because they have not vested as of such date, such options will be accelerated and will vest at the Trigger Date. In addition, under the Employee Matters Agreement, restricted stock awards granted to employees of CDI as of the IPO closing date will continue under their present terms and the terms of the plans under which they were granted. The modification date for these restricted stock and options occurred at the date the Employee Matters Agreement was adopted. However, no accounting charge will occur until the Trigger Date occurs and the impact of the modification, if any, can be measured.

Note 15 — Shareholders' Equity

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

The components of accumulated other comprehensive income (loss) as of December 31, 2008 and 2007 were as follows (in thousands):

	2008	2007

Cumulative foreign currency translation adjustment	$	(42,874)	$	28,260
Unrealized gain (loss) on hedges, net		9,178		(6,998)
Accumulated other comprehensive income (loss)	$	(33,696)	$	21,262

Note 16 — Stock Buyback Program

In June 2006, our Board of Directors authorized us to discretionarily purchase up to $50 million of our common stock in the open market. In October and November 2006, we purchased approximately 1.7 million shares under this program for a weighted average price of $29.86 per share, or $50.0 million thus ending the program.

Note 17 — Related Party Transactions

Cal Dive International, Inc.

We have provided Cal Dive certain management and administrative services including: (i) accounting, treasury, payroll and other financial services; (ii) legal, insurance and claims services; (iii) information systems, network and communication services; (iv) employee benefit services (including direct third-party group insurance costs and 401(k) contribution matching costs discussed below); and (v) corporate facilities management services. Total allocated costs to Cal Dive for such services were approximately $4 million, $3.6 million and $16.5 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Included in these costs are costs related to the participation by CDI’s employees in our employee benefit plans through December 31, 2007, including employee medical insurance and a defined contribution 401(k) retirement plan. These costs were recorded as a component of operating expenses and were approximately $9.2 million and $5.8 million for the years ended December 31, 2007 and 2006, respectively. Our defined contribution 401(k) retirement plan is further disclosed in Note 14.

In addition, through December 31, 2007, Cal Dive provided to us operational and field support services including: (i) training and quality control services; (ii) marine administration services; (iii) supply chain and base operation services; (iv) environmental, health and safety services; (v) operational facilities management services; and (vi) human resources. Total allocated costs to us for such services were approximately $3.4 million and $5.6 million for the years ended December 31, 2007 and 2006, respectively. These amounts are eliminated in the accompanying consolidated financial statements.

In contemplation of the IPO of CDI, we entered into intercompany agreements with CDI that address the rights and obligations of each respective company, including a Master Agreement, a Corporate Services Agreement, an Employee Matters Agreement and a Tax Matters Agreement. The Master Agreement describes and provides a framework for the separation of our business from CDI’s business, allocates liabilities (including potential liabilities related to litigation) between the parties, allocates responsibilities and provides standards for each of the parties’ conduct going forward (e.g., coordination regarding financial reporting), and sets forth the indemnification obligations of each party to the other. In addition, the Master Agreement provides us with a preferential right to use a specified number of CDI’s vessels in accordance with the terms of such agreement.

Pursuant to the Corporate Services Agreement, each party agrees to provide specified services to the other party, including administrative and support services for the time period specified therein. Generally after we cease to own more than 50% of the total voting power of CDI common stock, all services may be terminated by either party upon 60 days notice, but a longer notice period is applicable for selected services. Each of the services shall be provided in exchange for a monthly charge as calculated for each service (based on relative revenues, number of users for a particular service, or other specified measure). In general, under the Corporate Services Agreement as originally entered into by the parties we provide CDI with services related to the tax, treasury, audit, insurance (including claims) and information technology functions; CDI provides us with services related to the human resources, training and orientation functions, and certain supply chain and environmental, health and safety services. However, the

Corporate Services Agreement was amended effective January 1, 2008 and effective January 1, 2009 to reflect that CDI no longer provides us with these functions, and to reflect that we only provide CDI with certain information technology and insurance services.

Pursuant to the Employee Matters Agreement, except as otherwise provided, CDI generally accepts and assumes all employment related obligations with respect to all individuals who are employees of CDI as of the IPO closing date, including expenses related to existing options and restricted stock. Those employees are entitled to retain their Helix stock options and restricted stock grants under their original terms except as mandated by applicable law. The Employee Matters Agreement also permitted CDI employees to participate in our Employee Stock Purchase Plan for the offering period that ended June 30, 2007, and CDI paid us $1.6 million in July 2007, which was the fair market value of the shares of our stock purchased by such employees.

Pursuant to the Tax Matters Agreement, we are generally responsible for all federal, state, local and foreign income taxes that are attributable to CDI for all tax periods ending on the IPO; CDI is generally responsible for all such taxes beginning after the IPO. In addition, the agreement provides that for a period of up to ten years, CDI is required to make annual payments to us equal to 90% of tax benefits derived by CDI from tax basis adjustments resulting from the “Boot” gain recognized by us as a result of the distributions made to us as part of the IPO transaction. See Note 12 for more detailed disclosure of the Tax Matters Agreement.

Other

In April 2000, we acquired a 20% working interest in Gunnison, a Deepwater Gulf of Mexico prospect of Kerr-McGee. Financing for the exploratory costs of approximately $20 million was provided by an investment partnership (OKCD Investments, Ltd. or “OKCD”), the investors of which include current and former Helix senior management, in exchange for a revenue interest that is an overriding royalty interest of 25% of Helix’s 20% working interest. Production from the Gunnison field commenced in December 2003. We have made payments to OKCD totaling $21.6 million, $22.1 million and $34.6 million in the years ended December 31, 2008, 2007 and 2006 respectively. Our Chief Executive Officer, Owen Kratz, through Class A limited partnership interests in OKCD, personally owns approximately 74% of the partnership. Martin Ferron, our former President and Chief Executive Officer, owns approximately 1.1% of the partnership and A. Wade Pursell, our former Executive Vice President and Chief Financial Officer, owns approximately .43% of the partnership. In 2000, OKCD also awarded Class B limited partnership interests to key Helix employees.

During 2008, 2007 and 2006, we paid $3.4 million, $12.3 million and $6.1 million, respectively, to Weatherford International, Ltd. (“Weatherford”), an oil and gas industry company, for services provided to us. A member of our board of directors is part of the senior management team of Weatherford. During 2008, we paid $0.2 million to Tesco Corporation (“Tesco”) for services provided to us. A current member of our executive management team is a former member of Tesco’s executive management team.

Note 18 — Commitments and Contingencies

Lease Commitments

We lease several facilities, ROVs and vessels under noncancelable operating leases. Future minimum rentals under these leases are approximately $191.6 million at December 31, 2008 with $84.9 million due in 2009, $40.4 million in 2010, $35.3 million in 2011, $17.6 million in 2012, $4.0 million in 2013 and $9.4 million thereafter. Total rental expense under these operating leases was approximately $59.6 million, $76.0 million and $25.3 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Insurance

We carry Hull and Increased Value insurance which provides coverage for physical damage up to an agreed amount for each vessel. The deductibles are based on the value of the vessel with a maximum deductible of $1.0 million on the Q4000 and Well Enhancer and $500,000 on the Intrepid, Seawell, Express and Kestrel. Other vessels carry deductibles between $25,000 and $350,000. 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, including divers and tenders and marine crews, are covered by Maritime Employers Liability insurance policy which covers Jones Act exposures and includes a deductible of $100,000 per occurrence plus a $2.0 million annual aggregate deductible. In addition to the liability policies named above, we currently carry various layers of Umbrella Liability for total limits of $500 million excess of primary limits. Our self-insured retention on our medical and health benefits program for employees is $250,000 per participant.

We incur workers' compensation and other insurance claims in the normal course of business, which management believes are covered by insurance. The Company analyzes each claim for potential exposure and estimates the ultimate liability of each claim. Our liability at December 31, 2008 and 2007, above the applicable deductible limits, were $7.9 million and $14.2 million, respectively. The related receivable from insurance companies at December 31, 2008 and 2007 were $7.9 million and $10.2 million, respectively. These amounts are reflected in Accrued Liabilities and Other Current Assets in the consolidated balance sheet (Note 8). We have not incurred any significant losses as a result of claims denied by our insurance carriers. Our services are provided in hazardous environments where accidents involving catastrophic damage or loss of life could occur, and litigation arising from such an event may result in our being named a defendant in lawsuits asserting large claims. Although there can be no assurance the amount of insurance we carry is sufficient to protect us fully in all events, or that such insurance will continue to be available at current levels of cost or coverage, we believe that our insurance protection is adequate for our business operations. A successful liability claim for which we are underinsured or uninsured could have a material adverse effect on our business.

Litigation and Claims

On December 2, 2005, we received an order from the U.S. Department of the Interior Minerals Management Service ("MMS") that the price threshold for both oil and gas was exceeded for 2004 production and that royalties were due on such production notwithstanding the provisions of the Outer Continental Shelf Deep Water Royalty Relief Act of 2005 ("DWRRA"), which was intended to stimulate exploration and production of oil and natural gas in the deepwater Gulf of Mexico by providing relief from the obligation to pay royalty on certain federal leases up to certain specified production volumes. Our only oil and gas leases affected by this dispute are Garden Banks Blocks 667, 668 and 669 ("Gunnison"). On May 2, 2006, the MMS issued another order that superseded the December 2005 order, and claimed that royalties on gas production are due for 2003 in addition to oil and gas production in 2004. The May 2006 Order also seeks interest on all royalties allegedly due. We filed a timely notice of appeal with respect to both the December 2005 Order and the May 2006 Order. We received an additional order from the MMS dated September 30, 2008 stating that the price thresholds for oil and gas were exceeded for 2005, 2006 and 2007 production and that royalties and interest are payable. We appealed this order on the same basis as the previous orders. Other operators in the Deep Water Gulf of Mexico who have received notices similar to ours are seeking royalty relief under the DWRRA, including Kerr-McGee, the operator of Gunnison. In March of 2006, Kerr-McGee filed a lawsuit in federal district court challenging the enforceability of price thresholds in certain deepwater Gulf of Mexico Leases, including ours. On October 30, 2007, the federal district court in the Kerr-McGee case entered judgment in favor of Kerr-McGee and held that the Department of the Interior exceeded its authority by including the price thresholds in the subject leases. The government filed a notice of appeal of that decision on December 21, 2007. As a result of this dispute, we have recorded reserves for the disputed royalties (and any other royalties that may be claimed for production during 2005, 2006 and 2007) plus interest at 5% for our portion of the Gunnison related MMS claim. The total reserved amount at December 31, 2008 was approximately $69.7 million and is included in Other Long-Term Liabilities in the accompanying consolidated balance sheet. On January 12, 2009, the United States Court of Appeals for the Fifth Circuit affirmed the decision of the district court in favor of Kerr-McGee, holding that the DWRRA unambiguously provides that royalty suspensions up to certain production volumes established by Congress apply to leases that qualify under the DWRRA.

Although the above discussed matters may have the potential for additional liability and may have an impact on our consolidated financial results for a particular reporting period, we believe that the outcome of all such matters and proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Contingencies

During the fourth quarter of 2006, Horizon received a tax assessment from the SAT, the Mexican taxing authority, for approximately $23 million related to fiscal 2001, including penalties, interest and monetary correction. The SAT's assessment claims unpaid taxes related to services performed among the Horizon subsidiaries that CDI acquired at the time it acquired Horizon. CDI believes under the Mexico and United States double taxation treaty that these services are not taxable and that the tax assessment itself is invalid. On February 14, 2008, CDI received notice from the SAT upholding the original assessment. On April 21, 2008, CDI filed a petition in Mexico tax court disputing the assessment. We believe that CDI's position is supported by law and CDI intends to vigorously defend its position. However, the ultimate outcome of this litigation and CDI's potential liability from this assessment, if any, cannot be determined at this time. Nonetheless, an unfavorable outcome with respect to the Mexico tax assessment could have a material adverse effect on our financial position and results of operations. Horizon's 2002 through 2007 tax years remain subject to examination by the appropriate governmental agencies for Mexico tax purposes, with 2002 through 2004 currently under audit.

Commitments

We are converting the Caesar (acquired in January 2006 for $27.5 million in cash) into a deepwater pipelay vessel. Total conversion costs are estimated to range between $210 million and $230 million, of which approximately $158.9 million had been incurred, with an additional $11.8 million committed, at December 31, 2008. We expect the Caesar to join our fleet in the second half of 2009.

We are also constructing the Well Enhancer, a multi-service dynamically positioned dive support/well intervention vessel that will be capable of working in the North Sea and West of Shetlands to support our expected growth in that region. Total construction costs for the Well Enhancer is expected to range between $200 million and $220 million. We expect the Well Enhancer to join our fleet in the second quarter 2009. At December 31, 2008, we had incurred approximately $149.7 million, with an additional $31.2 million committed to this project.

Further, we, along with Kommandor Rømø, a Danish corporation, formed a joint venture company called Kommandor LLC to convert a ferry vessel into a floating production unit to be named the Helix Producer I. The total cost of the ferry and the conversion is estimated to range between $150 million and $160 million. We have provided $84.7 million in construction financing through December 31, 2008 to the joint venture on terms that would equal an arms length financing transaction, and Kommandor Rømø has provided $5 million on the same terms.

Total equity contributions and indebtedness guarantees provided by Kommandor Rømø are expected to total $42.5 million. The remaining costs to complete the project will be provided by Helix through equity contributions. Under the terms of the operating agreement of the joint venture, if Kommandor Rømø elects not to make further contributions to the joint venture, the ownership interests in the joint venture will be adjusted based on the relative contributions of each partner (including guarantees of indebtedness) to the total of all contributions and project financing guarantees.

Upon completion of the initial conversion, scheduled for second quarter 2009, we will charter the Helix Producer I from Kommandor LLC, and plan to install, at 100% our cost, processing facilities and a disconnectable fluid transfer system on the Helix Producer I for use on our Phoenix field. The cost of these additional facilities is estimated to range between $195 million and $205 million and the work is expected to be completed in early 2010. As of December 31, 2008, approximately $210.1 million of costs related to the purchase of the Helix Producer I ($20 million), conversion of the Helix Producer I and construction of the additional facilities had been incurred, with an additional $4.9 million committed. The total estimated cost of the vessel, initial conversion and the additonal facilties will range approximately between $345 million and $365 million. Kommandor LLC qualified as a variable interest entity under FIN 46(R). We determined that we were the primary beneficiary of Kommandor LLC and thus have consolidated the financial results of Kommandor LLC as of December 31, 2008 in our Production Facilities segment. Kommandor LLC has been a development stage enterprise since its formation in October 2006.

As of December 31, 2008, we have also committed approximately $106.3 million in additional capital expenditures for exploration, development and drilling costs related to our oil and gas properties.

Note 19 — Business Segment Information

Our operations are conducted through the following lines of business: contracting services operations and oil and gas operations. We have disaggregated our contracting services operations into three reportable segments in accordance with SFAS No. 131: Contracting Services, Shelf Contracting and Production Facilities. As a result, our reportable segments consist of the following: Contracting Services, Shelf Contracting, Oil and Gas and Production Facilities. Contracting Services operations include deepwater pipelay, well operations, robotics and reservoir and well tech services. Shelf Contracting operations consist of CDI, which include all assets deployed primarily for diving-related activities and shallow water construction. All material Intercompany transactions between the segments have been eliminated.

We evaluate our performance based on income before income taxes of each segment. Segment assets are comprised of all assets attributable to the reportable segment. The majority of our Production Facilities segment (Deepwater Gateway and Independence Hub) are accounted for under the equity method of accounting. Our investment in Kommandor LLC was consolidated in accordance with FIN 46 and is included in our Production Facilities segment.

The following summarizes certain financial data by business segment:

	Year Ended December 31, 2008	2007	2006
		(in thousands)	
Revenues —			
Contracting Services	$ 996,535	$ 708,833	$ 485,246
Shelf Contracting	856,906	623,615	509,917
Oil and Gas	545,853	584,563	429,607
Intercompany elimination	(250,945)	(149,566)	(57,846)
Total	$ 2,148,349	$ 1,767,445	$ 1,366,924
Income (loss) from operations —			
Contracting Services	$ 133,181	$ 130,116	$ 90,250
Shelf Contracting (1)	179,711	183,130	185,366
Oil and Gas	(731,565)	123,353	132,104
Production Facilities (2)	(719)	(847)	(1,051)
Intercompany elimination	(26,165)	(23,008)	(8,024)
Total (5)	$ (445,557)	$ 412,744	$ 398,645
Net interest expense and other —			
Contracting Services (4)	$ 29,822	$ (1,163)	$ 20,444
Shelf Contracting	22,285	9,259	(163)
Oil and Gas	26,000	49,580	14,293
Production Facilities	3,305	1,768	60
Total	$ 81,412	$ 59,444	$ 34,634
Equity in losses of OTSL, inclusive of impairment	$ —	$ (10,841)	$ (487)
Equity in earnings of equity investments excluding OTSL	$ 31,971	$ 30,539	$ 18,617
Income (loss) before income taxes —			
Contracting Services (3)	$ 103,579	$ 283,099	$ 293,144
Shelf Contracting (1)	157,426	163,031	185,042
Oil and Gas	(757,565)	73,773	117,811
Production Facilities (2)	27,727	27,799	17,302
Intercompany elimination	(26,165)	(23,008)	(8,024)
Total	$ (494,998)	$ 524,694	$ 605,275
Provision (benefit) for income taxes —			
Contracting Services	$ 45,667	$ 82,398	$ 140,306
Shelf Contracting	47,927	57,430	65,710
Oil and Gas	(15,092)	24,896	45,084
Production Facilities	11,475	10,204	6,056
Total	$ 89,977	$ 174,928	$ 257,156
Identifiable assets —			
Contracting Services	$ 1,595,105	$ 1,177,431	$ 1,313,206
Shelf Contracting	1,309,608	1,274,050	452,153
Oil and Gas	1,708,428	2,634,238	2,282,715
Production Facilities	457,197	366,634	242,113
Total	$ 5,070,338	$ 5,452,353	$ 4,290,187
Capital expenditures —			
Contracting Services	$ 258,660	$ 287,577	$ 130,938
Shelf Contracting	83,108	30,301	38,086

Oil and Gas		404,308		519,632		282,318
Production Facilities		110,300		123,545		45,327
Total	$	856,376	$	961,055	$	496,669
Depreciation and amortization —						
Contracting Services	$	49,110	$	40,850	$	34,165
Shelf Contracting		71,195		40,698		24,515
Oil and Gas		215,605		250,371		134,967
Total	$	335,910	$	331,919	$	193,647

(1) Includes $(10.8) million and $(0.5) million equity in (losses) earnings from investment in OTSL in 2007 and 2006, respectively.

(2) Represents selling and administrative expense of Production Facilities incurred by us. See Equity in Earnings of Production Facilities investments for earnings contribution.

(3) Includes pre-tax gain of $151.7 million related to the Horizon acquisition in 2007 and pre-tax gain of $223.1 million related to the initial public offering of CDI common stock and transfer of debt through dividend distributions from CDI in 2006.

(4) Includes interest expense related to the Term Loan. The proceeds from the Term Loan were used to fund the cash portion of the Remington acquisition.

(5) Includes $715 million of goodwill and other intangible asset impairment charges for year ending December 31, 2008, including $10.7 related to the Contracting Services segment.. Also includes approximately $215.7 million and $64.1 million of asset impairment charges for certain oil and gas properties for the years ended December 31, 2008 and 2007 respectively. There were no asset impairment charges in 2006.

Intercompany segment revenues during the years ended December 31, 2008, 2007 and 2006 were as follows (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Contracting Services	$ 195,541	$ 115,864	$ 42,585
Shelf Contracting	55,404	33,702	15,261
Total	$ 250,945	$ 149,566	$ 57,846

Intercompany segment profit (which only relates to intercompany capital projects) during the years ended December 31, 2008, 2007 and 2006 were as follows (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Contracting Services	$ 21,099	$ 10,026	$ 2,460
Shelf Contracting	5,066	12,982	5,564
Total	$ 26,165	$ 23,008	$ 8,024

Revenue by geographic region during the years ended December 31, 2008, 2007 and 2006 were as follows (in thousands):

	Year Ended December 31,		
	2008	2007	2006
United States	$ 1,394,246	$ 1,261,844	$ 1,063,821
United Kingdom	181,108	230,189	190,064
India	214,288	36,433	—
Other	358,707	238,979	113,039
Total	$ 2,148,349	$ 1,767,445	$ 1,366,924

We include the property and equipment, net 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,		
	2008	2007	2006
United States	$ 3,170,866	$ 3,014,283	$ 2,068,342
United Kingdom	207,156	189,117	110,451
Other	41,568	41,288	33,665
Total	$ 3,419,590	$ 3,244,688	$ 2,212,458

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Note 20 — Allowance Accounts

The following table sets forth the activity in our valuation accounts for each of the three years in the period ended December 31, 2008 (in thousands):

	Allowance for Uncollectible Accounts	Deferred Tax Asset Valuation Allowance
Balance, December 31, 2005	$ 585	$ —
Additions	3,598	—
Deductions	(3,201)	—
Balance, December 31, 2006	982	—
Additions	5,122	2,967
Deductions	(3,230)	—
Balance, December 31, 2007	2,874	2,967
Additions	9,434	350
Deductions	(6,403)	—
Balance, December 31, 2008	$ 5,905	$ 3,317

See Note 2 for a detailed discussion regarding our accounting policy on Accounts Receivable and Allowance for Uncollectible Accounts and Note 12 for a detailed discussion of the valuation allowance related to our deferred tax assets.

Note 21 — Supplemental Oil and Gas Disclosures (Unaudited)

The following information regarding our oil and gas producing activities is presented pursuant to SFAS No. 69, Disclosures About Oil and Gas Producing Activities.

Capitalized Costs

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

	2008	2007
Unproved oil and gas properties	$ 99,787	$ 101,453
Proved oil and gas properties	2,472,036	2,228,924
Total oil and gas properties	2,571,823	2,330,377
Accumulated depletion, depreciation and amortization	(1,023,493)	(617,922)
Net capitalized costs	$ 1,548,330	$ 1,712,455

Included in capitalized costs of proved oil and gas properties being amortized is an estimate of our proportionate share of decommissioning liabilities assumed relating to these properties which are also reflected as decommissioning liabilities in the accompanying consolidated balance sheets at fair value on a discounted basis. At December 31, 2008 and 2007, our oil and gas operations' decommissioning liabilities were $225.8 million and $217.5 million, respectively.

Costs Incurred in Oil and Gas Producing Activities

The following table reflects the costs incurred in oil and gas property acquisition and development activities, including estimated decommissioning liabilities assumed, during the years indicated (in thousands):

	United States	United Kingdom	Total
Year Ended December 31, 2008 —			
Property acquisition costs:			
Proved properties	$ 17,684	$ —	$ 17,684
Unproved properties	13,392	—	13,392
Total property acquisition costs	31,076	—	31,076
Exploration costs	7,528	—	7,528
Development costs (1)	403,653	—	403,653
Asset retirement cost	26,891	—	26,891
Total costs incurred	$ 469,148	$ —	$ 469,148
Year Ended December 31, 2007 —			
Property acquisition costs:			
Proved properties	$ 12,703	$ —	$ 12,703
Unproved properties	16,347	—	16,347
Total property acquisition costs	29,050	—	29,050
Exploration costs	220,237	—	220,237
Development costs (1)	351,964	—	351,964
Asset retirement cost	58,082	—	58,082
Total costs incurred	$ 659,333	$ —	$ 659,333
Year Ended December 31, 2006 —			
Property acquisition costs:			
Proved properties	$ 770,307	$ 365	$ 770,672
Unproved properties	105,519	—	105,519
Total property acquisition costs	875,826	365	876,191
Exploration costs	143,459	—	143,459
Development costs (1)	159,688	—	159,688
Asset retirement cost	32,863	7,579	40,442
Total costs incurred	$ 1,211,836	$ 7,944	$ 1,219,780

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

Results of Operations for Oil and Gas Producing Activities
Amounts in thousands:

	United States	United Kingdom	Total
Year Ended December 31, 2008 —			
Revenues	$ 541,983	$ 3,870	$ 545,853
Production (lifting) costs	140,316	2,448	142,764
Exploration expenses (2)	32,926	—	32,926
Depreciation, depletion, amortization and accretion	198,144	959	199,103
Abandonment and impairment	935,971	—	935,971

Gain on sale of oil and gas properties	73,136	125	73,261
Selling and administrative	39,219	696	39,915
Pretax loss from producing activities	(731,457)	(108)	(731,565)
Income tax expense (benefit)	(16,242)	1,150	(15,092)
Results of oil and gas producing activities (1)	$ (715,215)	$ (1,258)	$ (716,473)

	United States	United Kingdom	Total
Year Ended December 31, 2007 —			
Revenues	$ 581,904	$ 2,659	$ 584,563
Production (lifting) costs	118,032	5,102	123,134
Exploration expenses (2)	26,725	—	26,725
Depreciation, depletion, amortization and accretion	228,083	615	228,698
Abandonment and impairment	85,145	—	85,145
Gain on sale of oil and gas properties	42,566	1,717	44,283
Selling and administrative	40,176	1,615	41,791
Pretax income (loss) from producing activities	126,309	(2,956)	123,353
Income tax expense (benefit)	26,240	(1,344)	24,896
Results of oil and gas producing activities (1)	$ 100,069	$ (1,612)	$ 98,457
Year Ended December 31, 2006 —			
Revenues	$ 429,607	$ —	$ 429,607
Production (lifting) costs	89,139	—	89,139
Exploration expenses (2)	43,115	—	43,115
Depreciation, depletion, amortization and accretion	134,967	—	134,967
Gain on sale of oil and gas properties	2,248	—	2,248
Selling and administrative	27,645	4,885	32,530
Pretax income (loss) from producing activities	136,989	(4,885)	132,104
Income tax expense (benefit)	47,527	(2,443)	45,084
Results of oil and gas producing activities (1)	$ 89,462	$ (2,442)	$ 87,020

(1) Excludes net interest expense and other.

(2) See Note 7 for additional information related to the components of our exploration costs.

Estimated Quantities of Proved Oil and Gas Reserves

We employ full-time experienced reserve engineers and geologists who are responsible for determining proved reserves in compliance with SEC guidelines. Our engineering reserve estimates were prepared based upon interpretation of production performance data and sub-surface information obtained from the drilling of existing wells. Our internal reservoir engineers and independent petroleum engineers analyzed 100% of our significant United States oil and gas fields on an annual basis (107 fields as of December 31, 2008). We consider any field with discounted future net revenues of 1% or greater of the total discounted future net revenues of all our fields to be significant. An "engineering audit," as we use the term, is a process involving an independent petroleum engineering firm's (Huddleston) extensive visits, collection and examination of all geologic, geophysical, engineering and economic data requested by the independent petroleum engineering firm. Our use of the term "engineering audit" is intended only to refer to the collective application of the procedures which Huddleston was engaged to perform and may be defined and used differently by other companies.

The engineering audit of our reserves by the independent petroleum engineers involves their rigorous examination of our technical evaluation, interpretation and extrapolations of well information such as flow rates and reservoir pressure declines as well as other technical information and measurements. Our internal reservoir engineers interpret this data to determine the nature of the reservoir and ultimately the quantity of estimated proved oil and gas reserves attributable to a specific property. Our proved reserves in this Annual Report include only quantities that we expect to recover commercially using current prices, costs, existing regulatory practices and technology. While we are reasonably certain that the estimated proved reserves will be produced, the timing and ultimate recovery can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and changes in projections of long-term oil and gas prices. Revisions can include upward or downward changes in the previously estimated volumes of proved reserves for existing fields due to evaluation of (1) already available geologic, reservoir or production data or (2) new geologic or reservoir data obtained from wells. Revisions can also include changes associated with significant changes in development strategy, oil and gas prices, or the related production equipment/facility capacity. Huddleston also examined our estimates with respect to reserve categorization, using the definitions for proved reserves set forth in Regulation S-X Rule 4-10(a) and subsequent SEC staff interpretations and guidance.

In the conduct of the engineering audit, Huddleston did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties or sales of production. However, if in the course of the examination something came to the attention of Huddleston which brought into question the validity or sufficiency of any such information or data, Huddleston did not rely on such information or data until it had satisfactorily resolved its questions relating thereto or had independently verified such information or data. Furthermore, in instances where decline curve analysis was not adequate in determining proved producing reserves, Huddleston evaluated our volumetric analysis, which included the analysis of production and pressure data. Each of the PUDs analyzed by Huddleston included volumetric analysis, which took into consideration recovery factors relative to the geology of the location and similar reservoirs. Where applicable, Huddleston examined data related to well spacing, including potential drainage from offsetting producing wells in evaluating proved reserves for un-drilled well locations.

The engineering audit by Huddleston included 100% of the producing properties and essentially all the non-producing and undeveloped properties. Properties for analysis were selected by us and Huddleston based on estimated discounted future net revenues. All of our significant properties were included in the engineering audit and such audited properties constituted approximately 97% of the total estimated discounted future net revenues. Huddleston also analyzed the methods utilized by us in the preparation of all of the estimated reserves and revenues. Huddleston's audit report represents that Huddleston believes our methodologies are consistent with the methodologies required by the SEC, SPE and FASB. There were no limitations imposed, nor limitations encountered by us or Huddleston.

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

	United States	United (2) Kingdom	Total
Total proved reserves at December 31, 2005	14,873	—	14,873
Revision of previous estimates	(607)	—	(607)
Production	(3,400)	—	(3,400)
Purchases of reserves in place	24,820	—	24,820
Sales of reserves in place	—	—	—
Extensions and discoveries	651	—	651
Total proved reserves at December 31, 2006 (1)	36,337	—	36,337
Revision of previous estimates	(473)	97	(376)
Production	(3,723)	—	(3,723)
Purchases of reserves in place	—	—	—
Sales of reserves in place	(1,858)	(49)	(1,907)
Extensions and discoveries	9,346	—	9,346
Total proved reserves at December 31, 2007	39,629	48	39,677
Revision of previous estimates	(250)	(48)	(298)
Production	(2,751)	—	(2,751)
Purchases of reserves in place	—	—	—
Sales of reserves in place	(5,277)	—	(5,277)
Extensions and discoveries	661	—	661
Total proved reserves at December 31, 2008	32,012		32,012
Total proved developed reserves as of :			
December 31, 2005	7,759	—	7,759
December 31, 2006	13,328	—	13,328

December 31, 2007	14,703	10	14,713
December 31, 2008	12,809	—	12,809

(1) Proved reserves at December 31, 2006 included approximately 17,573 MBbls acquired from the Remington acquisition.

(2) Reflects current 50% ownership in United Kingdom reserves in 2008 and 2007; 100% ownership in 2006.

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

	United States	United (2) Kingdom	Total
Total proved reserves at December 31, 2005	136,073	—	136,073
Revision of previous estimates	4,678	—	4,678
Production	(27,949)	—	(27,949)
Purchases of reserves in place	169,375	23,634	193,009
Sales of reserves in place	—	—	—
Extensions and discoveries	12,212	—	12,212
Total proved reserves at December 31, 2006 (1)	294,389	23,634	318,023
Revision of previous estimates	(12,209)	5,666	(6,543)
Production	(42,163)	(300)	(42,463)
Purchases of reserves in place	160	—	160
Sales of reserves in place	(2,932)	(14,700)	(17,632)
Extensions and discoveries	187,439	—	187,439
Total proved reserves at December 31, 2007	424,684	14,300	438,984

	United States	United (2) Kingdom	Total
Revision of previous estimates	(32,098)	(1,028)	(33,126)
Production	(30,490)	(322)	(30,812)
Purchases of reserves in place	—	—	—
Sales of reserves in place	(73,627)	—	(73,627)
Extensions and discoveries	171,987	—	171,987
Total proved reserves at December 31, 2008	460,456	12,950	473,406
Total proved developed reserves as of :			
December 31, 2005	55,321	—	55,321
December 31, 2006	156,251	—	156,251
December 31, 2007	134,047	1,500	135,547
December 31, 2008	256,794	950	257,744

(1) Proved reserves at December 31, 2006 included approximately 159,338 MMcf acquired from the Remington acquisition.

(2) Reflects current 50% ownership in United Kingdom reserves in 2008 and 2007; 100% ownership in 2006.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following table reflects the standardized measure of discounted future net cash flows relating to our interest in proved oil and gas reserves (in thousands):

	United States	United (1) Kingdom	Total
As of December 31, 2008 —			
Future cash inflows	$ 4,011,788	$ 113,054	$ 4,124,842

Future costs:			
Production	(584,165)	(12,584)	(596,749)
Development and abandonment	(784,080)	(33,150)	(817,230)
Future net cash flows before income taxes	2,643,543	67,320	2,710,863
Future income tax expense	(777,736)	(53,626)	(831,362)
Future net cash flows	1,865,807	13,694	1,879,501
Discount at 10% annual rate	(562,354)	(4,992)	(567,346)
Standardized measure of discounted future net cash flows	$ 1,303,453	$ 8,702	$ 1,312,155

	United States	United (1) Kingdom	Total
As of December 31, 2007 —			
Future cash inflows	$ 6,769,106	$ 126,700	$ 6,895,806
Future costs:			
Production	(622,842)	(42,350)	(665,192)
Development and abandonment	(883,923)	(46,600)	(930,523)
Future net cash flows before income taxes	5,262,341	37,750	5,300,091
Future income tax expense	(1,617,709)	(18,850)	(1,636,559)
Future net cash flows	3,644,632	18,900	3,663,532
Discount at 10% annual rate	(831,705)	(4,313)	(836,018)
Standardized measure of discounted future net cash flows	$ 2,812,927	$ 14,587	$ 2,827,514
As of December 31, 2006 —			
Future cash inflows	$ 3,814,201	$ 173,520	$ 3,987,721
Future costs:			
Production	(588,000)	(8,521)	(596,521)
Development and abandonment	(707,398)	(66,300)	(773,698)
Future net cash flows before income taxes	2,518,803	98,699	2,617,502
Future income tax expense	(776,120)	(53,791)	(829,911)
Future net cash flows	1,742,683	44,908	1,787,591
Discount at 10% annual rate	(416,738)	(9,910)	(426,648)
Standardized measure of discounted future net cash flows	$ 1,325,945	$ 34,998	$ 1,360,943

(1) Reflects current 50% ownership in United Kingdom reserves in 2008 and 2007; 100% ownership in 2006.

Future cash inflows are computed by applying year-end prices, adjusted for location and quality differentials on a property-by-property basis, to year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements at year-end. The discounted future cash flow estimates do not include the effects of our derivative instruments or forward sales agreements. See the following table for base prices used in determining the standardized measure:

	United States	United Kingdom	Total
Year Ended December 31, 2008 —			
Average oil price per Bbl	$ 42.76	$ —	$ 42.76
Average gas prices per Mcf	$ 5.74	$ 8.73	$ 5.83
Year Ended December 31, 2007 —			
Average oil price per Bbl	$ 93.98	$ 49.69	$ 93.92
Average gas prices per Mcf	$ 7.17	$ 8.69	$ 7.22
Year Ended December 31, 2006 —			
Average oil price per Bbl	$ 59.75	$ —	$ 59.75
Average gas prices per Mcf	$ 5.58	$ 7.23	$ 5.70

The future income tax expense was computed by applying the appropriate year-end statutory rates, with consideration of future tax rates already legislated, to the future pretax net cash flows less the tax basis of the associated properties. Future net cash flows are discounted at the prescribed rate of 10%. We caution that actual future net cash flows may vary considerably from these estimates. Although our estimates of total proved reserves, development costs and production rates were based on the best information available, the development and production of oil and gas reserves may not occur in the periods assumed. Actual prices realized, costs incurred and production quantities may vary significantly from those used. Therefore, such estimated future net cash flow computations should not be considered to represent our estimate of the expected revenues or the current value of existing proved reserves.

Changes in Standardized Measure of Discounted Future Net Cash Flows

Principal changes in the standardized measure of discounted future net cash flows attributable to our proved oil and gas reserves are as follows (in thousands):

	Year Ended December 31,		
	2008	2007	2006
Standardized measure, beginning of year	$ 2,827,514	$ 1,360,943	$ 727,062
Changes during the year:			
Sales, net of production costs	(403,089)	(461,430)	(340,468)
Net change in prices and production costs	(1,713,458)	1,208,823	(328,149)
Changes in future development costs	(109,775)	(17,689)	(49,357)
Development costs incurred	403,653	351,964	159,616
Accretion of discount	338,582	261,931	106,333
Net change in income taxes	700,071	(665,750)	(254,770)
Purchases of reserves in place	—	(951)	1,245,847
Extensions and discoveries	335,643	1,285,499	82,730
Sales of reserves in place	(566,332)	(247,344)	—
Net change due to revision in quantity estimates	(96,096)	(80,865)	(6,067)
Changes in production rates (timing) and other	(404,558)	(167,617)	18,166
Total	(1,515,359)	1,466,571	633,881
Standardized measure, end of year	$ 1,312,155	$ 2,827,514	$ 1,360,943

Note 22 — Resignation of Executive Officers

Martin Ferron resigned as our President and Chief Executive Officer effective February 4, 2008. Concurrently, Mr. Ferron resigned from our Board of Directors. Mr. Ferron remained employed by us through February 18, 2008, after which his employment terminated. At the time of Mr. Ferron's resignation, Owen Kratz, who served as Executive Chairman of Helix, resumed the role and assumed the duties of the President and Chief Executive Officer, and was subsequently elected as President and Chief Executive Officer of Helix. In February 2008, we recognized approximately $5.4 million of compensation expense (inclusive of the expenses recorded for the acceleration of unvested stock options and restricted stock) related to the separation agreement between us and Mr. Ferron.

Wade Pursell resigned as our Chief Financial Officer effective June 25, 2008. Mr. Pursell remained employed by us through July 4, 2008, after which his employment terminated. Anthony Tripodo, who served as the chairman of our audit committee on our Board of Directors, was elected by our Board of Directors as the new Chief Financial Officer effective June 25, 2008, at which time he resigned from our Board of Directors. We recognized approximately $2.0 million of compensation expense (inclusive of the expenses recorded for the acceleration of unvested stock options and restricted stock) related to the separation between us and Mr. Pursell.

Note 23 — Quarterly Financial Information (Unaudited)

The offshore marine construction industry in the Gulf of Mexico is highly seasonal as a result of weather conditions and the timing of capital expenditures by oil and gas companies. Historically, a substantial portion of our services has been performed during the summer and fall months. As a result, historically a disproportionate portion of our revenues and net income is earned during such period. The following is a summary of consolidated quarterly financial information for 2008 and 2007 (in thousands, except per share data):

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31, (1)
2008				
Net revenues	$ 450,737	$ 540,494	$ 616,216	$ 540,902
Gross profit (loss)	120,879	192,414	200,825	(133,450)
Net income (loss)	75,216	91,782	61,468	(859,314)
Net income (loss) applicable to common shareholders	74,335	90,902	60,587	(859,864)
Basic earnings (loss) per common share	0.82	1.00	0.67	(9.47)
Diluted earnings (loss) per common share	0.79	0.96	0.65	(9.47)

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2007				
Net revenues	$ 396,055	$ 410,574	$ 460,573	$ 500,243
Gross profit	135,615	141,765	166,318	70,058
Net income	56,765	58,647	83,773	121,293
Net income applicable to common shareholders	55,820	57,702	82,828	120,412
Basic earnings per common share	0.62	0.64	0.92	1.34
Diluted earnings per common share	0.60	0.61	0.88	1.25

(1) Includes $907.6 million of impairment charges to reduce goodwill and other indefinite lived intangible assets ($715 million) and certain oil and gas properties ($192.6 million) to their estimated fair value in fourth quarter of 2008.

Note 24 — Condensed Consolidated Guarantor and Non-Guarantor Financial Information

The payment of obligations under the Senior Unsecured Notes is guaranteed by all of our restricted domestic subsidiaries ("Subsidiary Guarantors") except for Cal Dive and its subsidiaries and Cal Dive I-Title XI, Inc. Each of these Subsidiary Guarantors is included in our consolidated financial statements and has fully and unconditionally guaranteed the Senior Unsecured Notes on a joint and several basis. As a result of these guarantee arrangements, we are required to present the following condensed consolidating financial information. The accompanying guarantor financial information is presented on the equity method of accounting for all periods presented. Under this method, investments in subsidiaries are recorded at cost and adjusted for our share in the subsidiaries' cumulative results of operations, capital contributions and distributions and other changes in equity. Elimination entries relate primarily to the elimination of investments in subsidiaries and associated intercompany balances and transactions.

HELIX ENERGY SOLUTIONS GROUP, INC.

CONDENSED CONSOLIDATING BALANCE SHEETS

	As of December 31, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
			(In thousands)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ 148,704	$ 4,983	$ 69,926	$ —	$ 223,613
Accounts receivable, net	125,882	97,300	210,556	—	433,738
Unbilled revenue	43,888	1,080	72,958	—	117,926
Other current assets	120,320	79,202	42,148	(66,640)	175,030
Total current assets	438,794	182,565	395,588	(66,640)	950,307
Intercompany	78,395	100,662	(101,813)	(77,244)	—
Property and equipment, net	168,054	2,007,807	1,248,207	(4,478)	3,419,590
Other assets:					
Equity investments in unconsolidated affiliates	—	—	197,287	—	197,287
Equity investments in affiliates	2,331,924	31,374	—	(2,363,298)	—
Goodwill, net	—	45,107	321,386	(275)	366,218
Other assets, net	52,006	37,967	75,977	(29,014)	136,936
	$ 3,069,173	$ 2,405,482	$ 2,136,632	$ (2,540,949)	$ 5,070,338
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 99,197	$ 139,074	$ 109,284	$ (1,320)	$ 346,235
Accrued liabilities	87,712	65,090	84,577	(4,356)	233,023
Income taxes payable	(104,487)	82,859	7,325	14,303	—
Current maturities of long-term debt	4,326	—	173,947	(84,733)	93,540
Total current liabilities	86,748	287,023	375,133	(76,106)	672,798
Long-term debt	1,614,267	—	379,720	(25,485)	1,968,502
Deferred income taxes	173,503	242,967	191,773	(3,779)	604,464
Decommissioning liabilities	—	191,260	3,405	—	194,665
Other long-term liabilities	—	73,549	10,706	(2,618)	81,637
Due to parent	(100,528)	(3,741)	100,528	3,741	—
Total liabilities	1,773,990	791,058	1,061,265	(104,247)	3,522,066
Minority interests	—	—	—	322,627	322,627
Convertible preferred stock	55,000	—	—	—	55,000
Shareholders' equity	1,240,183	1,614,424	1,075,367	(2,759,329)	1,170,645
	$ 3,069,173	$ 2,405,482	$ 2,136,632	$ (2,540,949)	$ 5,070,338

HELIX ENERGY SOLUTIONS GROUP, INC.

CONDENSED CONSOLIDATING BALANCE SHEETS

	As of December 31, 2007				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
			(In thousands)		
		ASSETS			
Current assets:					
Cash and cash equivalents	$ 3,507	$ 2,609	$ 83,439	$ —	$ 89,555
Accounts receivable, net	85,122	104,619	257,761	—	447,502
Unbilled revenue	14,232	(280)	50,678	—	64,630
Other current assets	74,665	45,752	55,529	(50,364)	125,582
Total current assets	177,526	152,700	447,407	(50,364)	727,269
Intercompany	38,989	50,860	(84,065)	(5,784)	—
Property and equipment, net	92,864	2,092,730	1,060,298	(1,204)	3,244,688
Other assets:					
Equity investments in unconsolidated affiliates	—	—	213,429	—	213,429
Equity investments in affiliates	3,020,092	30,046	—	(3,050,138)	—
Goodwill, net	—	757,752	332,281	(275)	1,089,758
Other assets, net	59,554	40,686	111,259	(34,290)	177,209
	$ 3,389,025	$ 3,124,774	$ 2,080,609	$ (3,142,055)	$ 5,452,353
		LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities:					
Accounts payable	$ 43,774	$ 207,222	$ 131,730	$ 41	$ 382,767
Accrued liabilities	40,415	71,945	110,443	(1,437)	221,366
Income taxes payable	7,271	(5,574)	4,380	(6,077)	—
Current maturities of long-term debt	4,327	2	113,975	(43,458)	74,846
Total current liabilities	95,787	273,595	360,528	(50,931)	678,979
Long-term debt	1,287,092	—	463,934	(25,485)	1,725,541
Deferred income taxes	137,967	318,492	178,130	(9,081)	625,508
Decommissioning liabilities	—	189,639	4,011	—	193,650
Other long-term liabilities	3,294	56,325	9,244	(5,680)	63,183
Due to parent	(35,681)	98,504	37,028	(99,851)	—
Total liabilities	1,488,459	936,555	1,052,875	(191,028)	3,286,861
Minority interests	—	—	—	263,926	263,926
Convertible preferred stock	55,000	—	—	—	55,000
Shareholders' equity	1,845,566	2,188,219	1,027,734	(3,214,953)	1,846,566
	$ 3,389,025	$ 3,124,774	$ 2,080,609	$ (3,142,055)	$ 5,452,353

HELIX ENERGY SOLUTIONS GROUP, INC.

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

	For The Year Ended December 31, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
			(in thousands)		
Net revenues	$ 404,591	$ 813,240	$ 1,204,982	$ (274,464)	$ 2,148,349
Cost of sales	347,433	554,628	863,483	(246,464)	1,519,080
Oil and gas impairments	—	215,675	—	—	215,675
Exploration expense	—	32,926	—	—	32,926
Gross profit (loss)	57,158	10,011	341,499	(28,000)	380,668
Goodwill and other intangible impairments	—	704,311	10,677	—	714,988
Gain on sale of assets, net	—	73,136	335	—	73,471
Selling and administrative expenses	42,194	47,372	99,510	(4,368)	184,708
Income (loss) from operations	14,964	(668,536)	231,647	(23,632)	(445,557)
Equity in earnings of unconsolidated affiliates	—	—	31,971	—	31,971
Equity in earnings (losses) of affiliates	(584,299)	1,328	—	582,971	
Net interest expense and other	14,120	25,367	42,017	(92)	81,412
Income (loss) before income taxes	(583,455)	(692,575)	221,601	559,431	(494,998)
Provision for income taxes	33,149	2,909	63,215	(9,296)	89,977
Minority interest	—	—	—	45,873	45,873
Net income (loss)	(616,604)	(695,484)	158,386	522,854	(630,848)
Preferred stock dividends	3,192	—	—	—	3,192
Net income (loss) applicable to common shareholders	$ (619,796)	$ (695,484)	$ 158,386	$ 522,854	$ (634,040)

	For The Year Ended December 31, 2007				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
			(in thousands)		
Net revenues	$ 262,007	$ 769,648	$ 909,349	$ (173,559)	$ 1,767,445
Cost of sales	201,001	514,653	595,656	(148,418)	1,162,892
Oil and gas impairments	—	64,072	—	—	64,072
Exploration expense	—	26,725	—	—	26,725
Gross profit, (loss)	61,006	164,198	313,693	(25,141)	513,756
Gain on sale of assets, net	1,960	42,566	5,842	—	50,368
Selling and administrative expenses	38,063	44,940	71,510	(3,133)	151,380
Income from operations	24,903	161,824	248,025	(22,008)	412,744
Equity in earnings of unconsolidated affiliates	—	—	19,698	—	19,698
Equity in earnings of affiliates	219,280	15,140	—	(234,420)	—
Gain on subsidiary equity transaction	151,696	—	—	—	151,696
Net interest expense and other	(14,893)	49,064	20,929	4,344	59,444
Income before income taxes	410,772	127,900	246,794	(260,772)	524,694
Provision for income taxes	73,166	39,871	71,115	(9,224)	174,928
Minority interest	—	—	113	29,175	29,288
Net income (loss)	337,606	88,029	175,566	(280,723)	320,478

Preferred stock dividends	3,716	—	—	—	3,716
Net income applicable to common shareholders	$ 333,890	$ 88,029	$ 175,566	$ (280,723)	$ 316,762

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HELIX ENERGY SOLUTIONS GROUP, INC.

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

	For The Year Ended December 31, 2006				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
	(in thousands)				
Net revenues	$ 173,976	$ 569,074	$ 708,499	$ (84,625)	$ 1,366,924
Cost of sales	120,566	334,979	428,524	(75,668)	808,401
Exploration expense	—	43,115	—	—	43,115
Gross profit, (loss)	53,410	190,980	279,975	(8,957)	515,408
Gain on sale of assets, net	220	2,248	349	—	2,817
Selling and administrative expenses	33,838	33,135	53,823	(1,216)	119,580
Income from operations	19,792	160,093	226,501	(7,741)	398,645
Equity in earnings of unconsolidated affiliates	—	—	18,130	—	18,130
Equity in earnings of affiliates	255,110	9,996	—	(265,106)	—
Gain on subsidiary equity transaction	223,134	—	—	—	223,134
Net interest expense and other	13,578	14,301	6,755	—	34,634
Income before income taxes	484,458	155,788	237,876	(272,847)	605,275
Provision for income taxes	131,484	54,703	73,676	(2,707)	257,156
Minority interest	—	—	179	546	725
Net income (loss)	352,974	101,085	164,021	(270,686)	347,394
Preferred stock dividends	3,358	—	—	—	3,358
Net income applicable to common shareholders	$ 349,616	$ 101,085	$ 164,021	$ (270,686)	$ 344,036

HELIX ENERGY SOLUTIONS GROUP, INC.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	For The Year Ended December 31, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
			(In thousands)		
Cash flow from operating activities:					
Net income (loss)	$ (616,604)	$ (695,484)	$ 158,386	$ 522,854	$ (630,848)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:					
Equity in earnings of unconsolidated affiliates	—	—	2,803	—	2,803
Equity in earnings of affiliates	584,299	(1,328)	—	(582,971)	—
Other adjustments	(54,077)	967,933	111,056	40,852	1,065,764
Net cash provided by (used in) operating activities	(86,382)	271,121	272,245	(19,265)	437,719
Cash flows from investing activities:					
Capital expenditures	(75,003)	(513,024)	(267,503)	—	(855,530)
Acquisition of businesses, net of cash acquired	—	—	—	—	—
Investments in equity investments	—	—	(846)	—	(846)
Distributions from equity investments, net	—	—	11,586	—	11,586
Increases in restricted cash	—	(614)	—	—	(614)
Proceeds from insurance	—	13,200	—	—	13,200
Proceeds from sales of property	—	271,758	2,472	—	274,230
Net cash used in investing activities	(75,003)	(228,680)	(254,291)	—	(557,974)
Cash flows from financing activities:					
Borrowings on revolver	1,021,500	—	61,100	—	1,082,600
Repayments on revolver	(690,000)	—	(61,100)	—	(751,100)
Repayments of debt	(4,326)	—	(64,014)	—	(68,340)
Deferred financing costs	(1,796)	—	—	—	(1,796)
Capital lease payments	—	—	(1,505)	—	(1,505)
Preferred stock dividends paid	(3,192)	—	—	—	(3,192)
Repurchase of common stock	(3,925)	—	—	—	(3,925)
Excess tax benefit from stock-based compensation	1,335	—	—	—	1,335
Exercise of stock options, net	2,139	—	—	—	2,139
Intercompany financing	(15,153)	(40,067)	35,955	19,265	—
Net cash provided by (used in) financing activities	306,582	(40,067)	(29,564)	19,265	256,216
Effect of exchange rate changes on cash and cash equivalents	—	—	(1,903)	—	(1,903)
Net increase (decrease) in cash and cash equivalents	145,197	2,374	(13,513)	—	134,058
Cash and cash equivalents:					
Balance, beginning of year	3,507	2,609	83,439	—	89,555

Balance, end of year	$	148,704	$	4,983	$	69,926	$	—	$	223,613

HELIX ENERGY SOLUTIONS GROUP, INC.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For The Year Ended December 31, 2007

	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
			(In thousands)		
Cash flow from operating activities:					
Net income (loss)	$ 337,606	$ 88,028	$ 175,567	$ (280,723)	$ 320,478
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:					
Equity in earnings of unconsolidated affiliates	—	—	11,423	—	11,423
Equity in earnings of affiliates	(219,280)	(15,139)	—	234,419	—
Other adjustments	(272,936)	297,949	(139,733)	199,145	84,425
Net cash provided by (used in) operating activities	(154,610)	370,838	47,257	152,841	416,326
Cash flows from investing activities:					
Capital expenditures	(81,577)	(642,364)	(219,655)	—	(943,596)
Acquisition of businesses, net of cash acquired	—	—	(147,498)	—	(147,498)
Sales of short-term investments	285,395	—	—	—	285,395
Investments in equity investments	—	—	(17,459)	—	(17,459)
Distributions from equity investments, net	—	—	6,679	—	6,679
Increases in restricted cash	—	(1,112)	—	—	(1,112)
Proceeds from sales of property	—	53,547	24,526	—	78,073
Other, net	—	(136)	—	—	(136)
Net cash provided by (used in) investing activities	203,818	(590,065)	(353,407)	—	(739,654)
Cash flows from financing activities:					
Borrowings on revolver	472,800	—	31,500	—	504,300
Repayments on revolver	(454,800)	—	(332,668)	—	(787,468)
Borrowings under debt	550,000	—	380,000	—	930,000
Repayments of debt	(405,408)	—	(3,823)	—	(409,231)
Deferred financing costs	(11,377)	—	(5,788)	—	(17,165)
Capital lease payments	—	—	(2,519)	—	(2,519)
Preferred stock dividends paid	(3,716)	—	—	—	(3,716)
Repurchase of common stock	(9,904)	—	—	—	(9,904)
Excess tax benefit from stock-based compensation	580	—	—	—	580
Exercise of stock options, net	1,568	—	—	—	1,568
Intercompany financing	(327,933)	214,146	266,628	(152,841)	—
Net cash provided by (used in) financing activities	(188,190)	214,146	333,330	(152,841)	206,445
Effect of exchange rate changes on cash and cash equivalents	—	—	174	—	174
	(138,982)	(5,081)	27,354	—	(116,709)

Net increase (decrease) in cash and cash equivalents					
Cash and cash equivalents:					
Balance, beginning of year	142,489	7,690	56,085	—	206,264
Balance, end of year	$ 3,507	$ 2,609	$ 83,439	$ —	$ 89,555

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HELIX ENERGY SOLUTIONS GROUP, INC.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For The Year Ended December 31, 2006	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
			(In thousands)		
Cash flow from operating activities:					
Net income (loss)	$ 352,974	$ 101,085	$ 164,021	$ (270,686)	$ 347,394
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:					
Equity in earnings of unconsolidated affiliates	—	—	(1,879)	—	(1,879)
Equity in earnings of affiliates	(255,110)	(9,996)	—	265,106	—
Other adjustments	21,777	131,644	(20,326)	35,426	168,521
Net cash provided by (used in) operating activities	119,641	222,733	141,816	29,846	514,036
Cash flows from investing activities:					
Capital expenditures	(9,170)	(362,343)	(97,578)	—	(469,091)
Acquisition of businesses, net of cash acquired	—	(772,244)	(115,699)	—	(887,943)
Purchases of short-term investments	(285,395)	—	—	—	(285,395)
Investments in equity investments	—	—	(27,578)	—	(27,578)
Increases in restricted cash	—	(6,666)	—	—	(6,666)
Proceeds from sale of subsidiary stock	264,401	—	—	—	264,401
Proceeds from sales of property	514	15,000	16,828	—	32,342
Net cash provided by (used in) investing activities	(29,650)	(1,126,253)	(224,027)	—	(1,379,930)
Cash flows from financing activities:					
Borrowings on revolver	209,800	—	201,000	—	410,800
Repayments on revolver	(209,800)	—	—	—	(209,800)
Borrowings under debt	835,000	—	5,000	—	840,000
Repayments of debt	(2,100)	—	(3,641)	—	(5,741)
Deferred financing costs	(11,462)	—	(377)	—	(11,839)
Capital lease payments	—	—	(2,827)	—	(2,827)
Preferred stock dividends paid	(3,613)	—	—	—	(3,613)
Repurchase of common stock	(50,266)	—	—	—	(50,266)
Subsidiary stock issuance	—	—	264,401	(264,401)	—
Excess tax benefit from stock-based compensation	2,660	—	—	—	2,660
Exercise of stock options, net	8,886	—	—	—	8,886
Intercompany financing	(802,878)	907,869	(339,546)	234,555	—
Net cash provided by (used in) financing activities	(23,773)	907,869	124,010	(29,846)	978,260

Effect of exchange rate changes on cash and cash equivalents		—		—		2,818		—	2,818
Net increase in cash and cash equivalents		66,218		4,349		44,617		—	115,184
Cash and cash equivalents:									
Balance, beginning of year		76,271		3,341		11,468		—	91,080
Balance, end of year	$	142,489	$	7,690	$	56,085	$	—$	206,264

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

(a) Evaluation of disclosure controls and procedures. Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") as of the end of the fiscal year ended December 31, 2008. In its evaluation, management used the criterion set forth in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on this evaluation, the principal executive officer and the principal financial officer believe that our disclosure controls and procedures were effective as of the end of the fiscal year ended December 31, 2008 to ensure that information that is required to be disclosed by us in the reports we file or submit under the Exchange Act is (i) identified, recorded, processed, summarized and reported, on a timely basis and (ii) accumulated and communicated to our management, as appropriate, to allow timely decisions regarding required disclosure.

(b) Changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Securities Exchange Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We continued the implementation of our enterprise resource planning system, as planned and as previously reported, throughout 2008 with the final implementation completed on January 5, 2009. We continued to evolve our controls accordingly. Resulting impacts on internal controls over financial reporting were evaluated and determined not to be significant for the year ended December 31, 2008. However, the completion of the implementation effort may lead to our making additional changes in our internal controls over financial reporting in future fiscal periods.

(c) Changes in Internal Control. There was not any change in our internal control over financial reporting that occurred during the fourth quarter of fiscal 2008 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting and the Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting thereon are set forth in Part II, Item 8 of this report on Form 10-K on page 74 and page 76, respectively.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Except as set forth below, the information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with our 2009 Annual Meeting of Shareholders to be held on may 13, 2009. See also “Executive Officers of the Registrant” appearing in Part I of this Report.

Code of Ethics

We have adopted a Code of Business Conduct and Ethics for all directors, officers and employees as well as a Code of Ethics for Chief Executive Officer and Senior Financial Officers specific to those officers. Copies of these documents are available at our Website www.helixesg.com under Corporate Governance. Interested parties may also request a free copy of these documents from:

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

Item 11. Executive Compensation.

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with our 2009 Annual Meeting of Shareholders to be held on May 13, 2009.

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

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with our 2009 Annual Meeting of Shareholders to be held on May 13, 2009.

Item 13. Certain Relationships and Related Transactions.

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with our 2009 Annual Meeting of Shareholders to be held on May 13, 2009.

Item 14. Principal Accounting Fees and Services.

The information required by this Item is incorporated by reference to our definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection our 2009 Annual Meeting of Shareholders to be held on May 13, 2009.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

(1) Financial Statements.

The following financial statements included on pages 75 through 137 in this Annual Report are for the fiscal year ended December 31, 2008.

- Management's Report on Internal Control Over Financial Reporting
- Report of Independent Registered Public Accounting Firm
- Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting
- Consolidated Balance Sheets as of December 31, 2008 and 2007
- Consolidated Statements of Operations for the Years Ended December 31, 2008, 2007 and 2006
- Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2008, 2007 and 2006
- Consolidated Statements of Cash Flows for the Years Ended December 31, 2008, 2007 and 2006
- Notes to Consolidated Financial Statements.

All financial statement schedules are omitted because the information is not required or because the information required is in the financial statements or notes thereto.

(2) Exhibits.

Pursuant to Item 601(b)(4)(iii), the Registrant agrees to forward to the commission, upon request, a copy of any instrument with respect to long-term debt not exceeding 10% of the total assets of the Registrant and its consolidated subsidiaries.

The following exhibits are filed as part of this Annual Report:

Exhibits	
2.1	Agreement and Plan of Merger dated January 22, 2006, among Cal Dive International, Inc. and Remington Oil and Gas Corporation, incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K/A, filed by the registrant with the Securities and Exchange Commission on January 25, 2006 (the "Form 8-K/A").
2.2	Amendment No. 1 to Agreement and Plan of Merger dated January 24, 2006, by and among, Cal Dive International, Inc., Cal Dive Merger — Delaware, Inc. and Remington Oil and Gas Corporation, incorporated by reference to Exhibit 2.2 to the Form 8-K/A.
3.1	2005 Amended and Restated Articles of Incorporation, as amended, of registrant, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by registrant with the Securities and Exchange Commission on March 1, 2006.
3.2	

Second Amended and Restated By-Laws of Helix, as amended, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on September 28, 2006.

3.3 Certificate of Rights and Preferences for Series A-1 Cumulative Convertible Preferred Stock, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by registrant with the Securities and Exchange Commission on January 22, 2003 (the “2003 Form 8-K”).

3.4 Certificate of Rights and Preferences for Series A-2 Cumulative Convertible Preferred Stock, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by registrant with the Securities and Exchange Commission on June 28, 2004 (the “2004 Form 8-K”).

4.1	Credit Agreement dated July 3, 2006 by and among Helix Energy Solutions Group, Inc., and Bank of America, N.A., as administrative agent and as lender, together with the other lender parties thereto, incorporated by reference to Exhibit 4.1 to the registrant's Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on July 5, 2006.
4.2	Participation Agreement among ERT, Helix Energy Solutions Group, Inc., Cal Dive/Gunnison Business Trust No. 2001-1 and Bank One, N.A., et. al., dated as of November 8, 2001, incorporated by reference to Exhibit 4.2 to Form 10-K for the fiscal year ended December 31, 2001, filed by the registrant with the Securities and Exchange Commission on March 28, 2002 (the "2001 Form 10-K").
4.3	Form of Common Stock certificate, incorporated by reference to Exhibit 4.7 to the Form 8-A filed by the Registrant with the Securities and Exchange Commission on June 30, 2006.
4.4	Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of August 16, 2000, incorporated by reference to Exhibit 4.4 to the 2001 Form 10-K.
4.5	Amendment No. 1 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of January 25, 2002, incorporated by reference to Exhibit 4.9 to the Form 10-K/A filed with the Securities and Exchange Commission on April 8, 2003.
4.6	Amendment No. 2 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of November 15, 2002, incorporated by reference to Exhibit 4.4 to the Form S-3 filed with the Securities and Exchange Commission on February 26, 2003.
4.7	First Amended and Restated Agreement dated January 17, 2003, but effective as of December 31, 2002, by and between Helix Energy Solutions Group, Inc. and Fletcher International, Ltd., incorporated by reference to Exhibit 10.1 to the 2003 Form 8-K.
4.8	Amended and Restated Credit Agreement among Cal Dive/Gunnison Business Trust No. 2001-1, Energy Resource Technology, Inc., Helix Energy Solutions Group, Inc., Wilmington Trust Company, a Delaware banking corporation, the Lenders party thereto, and Bank One, NA, as Agent, dated July 26, 2002, incorporated by reference to Exhibit 4.12 to the Form 10-K/A filed with the Securities and Exchange Commission on April 8, 2003.
4.9	First Amendment to Amended and Restated Credit Agreement among Cal Dive/Gunnison Business Trust No. 2001-1, Energy Resource Technology, Inc., Helix Energy Solutions Group, Inc., Wilmington Trust Company, a Delaware banking corporation, the Lenders party thereto, and Bank One, NA, as Agent, dated January 7, 2003, incorporated by reference to Exhibit 4.13 to the Form 10-K/A filed with the Securities and Exchange Commission on April 8, 2003.
4.10	Second Amendment to Amended and Restated Credit Agreement among Cal Dive/Gunnison Business Trust No. 2001-1, Energy Resource Technology, Inc., Helix Energy Solutions Group, Inc., Wilmington Trust Company, a Delaware banking corporation, the Lenders party thereto, and Bank One, NA, as Agent, dated February 14, 2003, incorporated by reference to Exhibit 4.14 to the 2002 Form 10-K/A.
4.11	Lease with Purchase Option Agreement between Banc of America Leasing & Capital, LLC and Canyon Offshore Ltd. dated July 31, 2003 incorporated by reference to Exhibit 10.1 to the Form 10-Q for the fiscal quarter ended September 30, 2003, filed by the registrant with the Securities and Exchange Commission on November 13, 2003.
4.12	Amendment No. 3 Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of July 31, 2003, incorporated by reference to Exhibit 4.12 to Annual Report for the year ended December 31, 2004, filed by the registrant with the Securities Exchange Commission on March 16, 2005 (the "2004 10-K").
4.13	

	Amendment No. 4 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of December 15, 2004 , incorporated by reference to Exhibit 4.13 to the 2004 10-K.
4.14	Indenture relating to the 3.25% Convertible Senior Notes due 2025 dated as of March 30, 2005, between Cal Dive International, Inc. and JPMorgan Chase Bank, National Association, as Trustee., incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on April 4, 2005 (the “April 2005 8-K”).
4.15	Form of 3.25% Convertible Senior Note due 2025 (filed as Exhibit A to Exhibit 4.15).
4.16	Registration Rights Agreement dated as of March 30, 2005, between Cal Dive International, Inc. and Banc of America Securities LLC, as representative of the initial purchasers, incorporated by reference to Exhibit 4.3 to the April 2005 8-K.

4.17	Trust Indenture, dated as of August 16, 2000, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on October 6, 2005 (the “October 2005 8-K”).
4.18	Supplement No. 1 to Trust Indenture, dated as of January 25, 2002, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.2 to the October 2005 8-K.
4.19	Supplement No. 2 to Trust Indenture, dated as of November 15, 2002, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.3 to the October 2005 8-K.
4.20	Supplement No. 3 to Trust Indenture, dated as of December 14, 2004, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.4 to the October 2005 8-K.
4.21	Supplement No. 4 to Trust Indenture, dated September 30, 2005, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.5 to the October 2005 8-K.
4.22	Form of United States Government Guaranteed Ship Financing Bonds, Q4000 Series 4.93% Sinking Fund Bonds Due February 1, 2027 (filed as Exhibit A to Exhibit 4.21).
4.23	Form of Third Amended and Restated Promissory Note to United States of America, incorporated by reference to Exhibit 4.6 to the October 2005 8-K.
4.24	Term Loan Agreement by and among Kommandor LLC, Nordea Bank Norge ASA, as arranger and agent, Nordea Bank Finland Plc, as swap bank, together with the other lender parties thereto, effective as of June 13, 2007 incorporated by reference to Exhibit 4.7 to the registrants Quarterly Report on Form 10-Q for the fiscal quarter ended June 30, 2007, file by the registrant with the Securities and Exchange Commission on August 3, 2007.
4.25	Indenture, dated as of December 21, 2007, by and among Helix Energy Solutions Group, Inc., the Guarantors and Wells Fargo Bank, N.A. incorporated by reference to Exhibit 4.1 to the registrants Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on December 21, 2007 (the “December 2007 8-K”).
10.1	1995 Long Term Incentive Plan, as amended, incorporated by reference to Exhibit 10.3 to the Form S-1.
10.2 *	Amendment to 1995 Long Term Incentive Plan of Helix Energy Solutions Group, Inc.
10.3	2009 Long-Term Incentive Cash Plan of Helix Energy Solutions Group, Inc., incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on January 6, 2009 (the “January 2009 8-K”).
10.4	Form of Award Letter related to the 2009 Long-Term Incentive Cash Plan, incorporated by reference to Exhibit 10.2 to the January 2009 8-K.
10.5	Employment Agreement between Owen Kratz and Company dated February 28, 1999, incorporated by reference to Exhibit 10.5 to the Annual Report for the fiscal year ended December 31, 1998, filed by the registrant with the Securities and Exchange Commission on March 31, 1999 (the “1998 Form 10-K”).
10.6	Employment Agreement between Owen Kratz and Company dated November 17, 2008, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on November 19, 2008 (the “November 2008 8-K”).
10.7	Employment Agreement between Martin R. Ferron and Company dated February 28, 1999, incorporated by reference to Exhibit 10.6 of the 1998 Form 10-K.
10.8	Employment Agreement between A. Wade Pursell and Company dated January 1, 2002, incorporated by reference to Exhibit 10.7 of the 2001 Form 10-K.

10.9	Helix 2005 Long Term Incentive Plan, including the Form of Restricted Stock Award Agreement, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on May 12, 2005.
10.10 *	Amendment to 2005 Long Term Incentive Plan of Helix Energy Solutions Group, Inc.
10.11	Employment Agreement by and between Helix and Bart H. Heijermans, effective as of September 1, 2005, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on September 1, 2005.

10.12	Employment Agreement between Bart H. Heijermans and Company dated November 17, 2008, incorporated by reference to Exhibit 10.2 to the November 2008 8-K.
10.13	Employment Agreement between Alisa B. Johnson and Company dated September 18, 2006, incorporated by reference to Exhibit 10.2 to the 2006 Form 10-Q.
10.14	Employment Agreement between Alisa B. Johnson and Company dated November 17, 2008, incorporated by reference to Exhibit 10.3 to the November 2008 8-K.
10.15	Employment Letter from the Company to Robert P. Murphy dated December 21, 2006, incorporated by reference to Exhibit 10.9 to the 2006 Annual Report (“2006 Form 10-K”).
10.16 *	Amendment to Employment Agreement between Robert P. Murphy and Company effective January 1, 2009, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on December 12, 2008.
10.17	Master Agreement between the Company and Cal Dive International, Inc. dated December 8, 2006, incorporated by reference to Exhibit 10.10 to the 2006 Form 10-K.
10.18	Tax Agreement between the Company and Cal Dive International, Inc. dated December 14, 2006, incorporated by reference to Exhibit 10.11 to the 2006 Form 10-K.
10.19	Registration Rights Agreement dated as of December 21, 2007 by and among Helix Energy Solutions Group, Inc., the Guarantors named therein and Banc of America Securities LLC, as representative of the Initial Purchasers, incorporated by reference to Exhibit 10.1 to December 2007 8-K.
10.20	Purchase Agreement dated as of December 18, 2007 by and among Helix Energy Solutions Group, Inc., the Guarantors named therein and Banc of America Securities LLC, and the other Initial Purchasers named therein incorporated by reference to Exhibit 10.2 to the December 2007 8-K.
10.21	Amendment No. 1 to Credit Agreement, dated as of November 29, 2007, by and among Helix, as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto incorporated by reference to Exhibit 10.3 to the December 2007 8-K.
10.22	Letter Agreement by and between Helix Energy Solutions Group, Inc. and Martin R. Ferron dated February 8, 2008 incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on February 8, 2008 (the “February 2008 8-K”).
10.23	Letter Agreement by and between Helix Energy Solutions Group, Inc. and Alan Wade Pursell dated June 25, 2008 incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on June 30, 2008 (the “June 2008 8-K”).
10.24	Employment Agreement between Anthony Tripodo and the Company dated June 25, 2008, incorporated by reference to Exhibit 10.2 to the June 2008 8-K.
10.25	First Amendment to Employment Agreement between Anthony Tripodo and the Company dated November 17, 2008, incorporated by reference to Exhibit 10.5 to the November 2008 8-K.
10.26	Consulting Agreement by and between A. Wade Pursell and the Company dated July 4, 2008, incorporated by reference to Exhibit 10.1 to the registrants Quarterly Report on Form 10-Q, filed by the registrant with the Securities and Exchange Commission on August 1, 2008.
10.27	Employment Agreement between Lloyd A. Hajdik and Company dated November 17, 2008, incorporated by reference to Exhibit 10.4 to the November 2008 8-K.
10.28	Stock Repurchase Agreement between Company and Cal Dive International, Inc. dated January 23, 2009, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on January 28, 2009.
21.1*	List of Subsidiaries of the Company.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of Huddleston & Co., Inc.

31.1*	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer.
31.2*	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Anthony Tripodo, Chief Financial Officer
32.1**	Certification of Helix's Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes — Oxley Act of 2002

* Filed herewith.

** Furnished herewith.

SIGNATURES

Pursuant to the requirements of section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

HELIX ENERGY SOLUTIONS GROUP, INC.

By: /s/ ANTHONY TRIPODO
Anthony Tripodo
Executive Vice President and
Chief Financial Officer

March 2, 2009

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

Signature	Title	Date
/s/ OWEN KRATZ Owen Kratz	President, Chief Executive Officer and Director (principal executive officer)	March 2, 2009
/s/ ANTHONY TRIPODO Anthony Tripodo	Executive Vice President and Chief Financial Officer (principal financial officer)	March 2, 2009
/s/ LLOYD A. HAJDIK Lloyd A. Hajdik	Senior Vice President — Finance and Chief Accounting Officer (principal accounting officer)	March 2, 2009
/s/ GORDON F. AHALT Gordon F. Ahalt	Director	March 2, 2009
/s/ BERNARD J. DUROC-DANNER Bernard J. Duroc-Danner	Director	March 2, 2009
/s/ JOHN V. LOVOI John V. Lovoi	Director	March 2, 2009
/s/ T. WILLIAM PORTER T. William Porter	Director	March 2, 2009
/s/ WILLIAM L. TRANSIER William L. Transier	Director	March 2, 2009

/s/ JAMES A. WATT James A. Watt	Director	March 2, 2009

INDEX TO EXHIBITS

Exhibits	
2.1	Agreement and Plan of Merger dated January 22, 2006, among Cal Dive International, Inc. and Remington Oil and Gas Corporation, incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K/A, filed by the registrant with the Securities and Exchange Commission on January 25, 2006 (the "Form 8-K/A").
2.2	Amendment No. 1 to Agreement and Plan of Merger dated January 24, 2006, by and among, Cal Dive International, Inc., Cal Dive Merger — Delaware, Inc. and Remington Oil and Gas Corporation, incorporated by reference to Exhibit 2.2 to the Form 8-K/A.
3.1	2005 Amended and Restated Articles of Incorporation, as amended, of registrant, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by registrant with the Securities and Exchange Commission on March 1, 2006.
3.2	Second Amended and Restated By-Laws of Helix, as amended, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on September 28, 2006.
3.3	Certificate of Rights and Preferences for Series A-1 Cumulative Convertible Preferred Stock, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by registrant with the Securities and Exchange Commission on January 22, 2003 (the "2003 Form 8-K").
3.4	Certificate of Rights and Preferences for Series A-2 Cumulative Convertible Preferred Stock, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by registrant with the Securities and Exchange Commission on June 28, 2004 (the "2004 Form 8-K").
4.1	Credit Agreement dated July 3, 2006 by and among Helix Energy Solutions Group, Inc., and Bank of America, N.A., as administrative agent and as lender, together with the other lender parties thereto, incorporated by reference to Exhibit 4.1 to the registrant's Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on July 5, 2006.
4.2	Participation Agreement among ERT, Helix Energy Solutions Group, Inc., Cal Dive/Gunnison Business Trust No. 2001-1 and Bank One, N.A., et. al., dated as of November 8, 2001, incorporated by reference to Exhibit 4.2 to Form 10-K for the fiscal year ended December 31, 2001, filed by the registrant with the Securities and Exchange Commission on March 28, 2002 (the "2001 Form 10-K").
4.3	Form of Common Stock certificate, incorporated by reference to Exhibit 4.7 to the Form 8-A filed by the Registrant with the Securities and Exchange Commission on June 30, 2006.
4.4	Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of August 16, 2000, incorporated by reference to Exhibit 4.4 to the 2001 Form 10-K.
4.5	Amendment No. 1 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of January 25, 2002, incorporated by reference to Exhibit 4.9 to the Form 10-K/A filed with the Securities and Exchange Commission on April 8, 2003.
4.6	Amendment No. 2 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of November 15, 2002, incorporated by reference to Exhibit 4.4 to the Form S-3 filed with the Securities and Exchange Commission on February 26, 2003.
4.7	First Amended and Restated Agreement dated January 17, 2003, but effective as of December 31, 2002, by and between Helix Energy Solutions Group, Inc. and Fletcher International, Ltd., incorporated by reference to Exhibit 10.1 to the 2003 Form 8-K.
4.8	Amended and Restated Credit Agreement among Cal Dive/Gunnison Business Trust No. 2001-1, Energy Resource Technology, Inc., Helix Energy Solutions Group, Inc., Wilmington Trust Company, a Delaware banking corporation, the Lenders party thereto, and Bank One, NA, as

	Agent, dated July 26, 2002, incorporated by reference to Exhibit 4.12 to the Form 10-K/A filed with the Securities and Exchange Commission on April 8, 2003.
4.9	First Amendment to Amended and Restated Credit Agreement among Cal Dive/Gunnison Business Trust No. 2001-1, Energy Resource Technology, Inc., Helix Energy Solutions Group, Inc., Wilmington Trust Company, a Delaware banking corporation, the Lenders party thereto, and Bank One, NA, as Agent, dated January 7, 2003, incorporated by reference to Exhibit 4.13 to the Form 10-K/A filed with the Securities and Exchange Commission on April 8, 2003.

4.10	Second Amendment to Amended and Restated Credit Agreement among Cal Dive/Gunnison Business Trust No. 2001-1, Energy Resource Technology, Inc., Helix Energy Solutions Group, Inc., Wilmington Trust Company, a Delaware banking corporation, the Lenders party thereto, and Bank One, NA, as Agent, dated February 14, 2003, incorporated by reference to Exhibit 4.14 to the 2002 Form 10-K/A.
4.11	Lease with Purchase Option Agreement between Banc of America Leasing & Capital, LLC and Canyon Offshore Ltd. dated July 31, 2003 incorporated by reference to Exhibit 10.1 to the Form 10-Q for the fiscal quarter ended September 30, 2003, filed by the registrant with the Securities and Exchange Commission on November 13, 2003.
4.12	Amendment No. 3 Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of July 31, 2003, incorporated by reference to Exhibit 4.12 to Annual Report for the year ended December 31, 2004, filed by the registrant with the Securities Exchange Commission on March 16, 2005 (the "2004 10-K").
4.13	Amendment No. 4 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of December 15, 2004 , incorporated by reference to Exhibit 4.13 to the 2004 10-K.
4.14	Indenture relating to the 3.25% Convertible Senior Notes due 2025 dated as of March 30, 2005, between Cal Dive International, Inc. and JPMorgan Chase Bank, National Association, as Trustee., incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on April 4, 2005 (the "April 2005 8-K").
4.15	Form of 3.25% Convertible Senior Note due 2025 (filed as Exhibit A to Exhibit 4.15).
4.16	Registration Rights Agreement dated as of March 30, 2005, between Cal Dive International, Inc. and Banc of America Securities LLC, as representative of the initial purchasers, incorporated by reference to Exhibit 4.3 to the April 2005 8-K.
4.17	Trust Indenture, dated as of August 16, 2000, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on October 6, 2005 (the "October 2005 8-K").
4.18	Supplement No. 1 to Trust Indenture, dated as of January 25, 2002, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.2 to the October 2005 8-K.
4.19	Supplement No. 2 to Trust Indenture, dated as of November 15, 2002, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.3 to the October 2005 8-K.
4.20	Supplement No. 3 to Trust Indenture, dated as of December 14, 2004, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.4 to the October 2005 8-K.
4.21	Supplement No. 4 to Trust Indenture, dated September 30, 2005, between Cal Dive I-Title XI, Inc. and Wilmington Trust, as Indenture Trustee, incorporated by reference to Exhibit 4.5 to the October 2005 8-K.
4.22	Form of United States Government Guaranteed Ship Financing Bonds, Q4000 Series 4.93% Sinking Fund Bonds Due February 1, 2027 (filed as Exhibit A to Exhibit 4.21).
4.23	Form of Third Amended and Restated Promissory Note to United States of America, incorporated by reference to Exhibit 4.6 to the October 2005 8-K.
4.24	Term Loan Agreement by and among Kommandor LLC, Nordea Bank Norge ASA, as arranger and agent, Nordea Bank Finland Plc, as swap bank, together with the other lender parties thereto, effective as of June 13, 2007 incorporated by reference to Exhibit 4.7 to the registrants Quarterly Report on Form 10-Q for the fiscal quarter ended June 30, 2007, file by the registrant with the

	Securities and Exchange Commission on August 3, 2007.
4.25	Indenture, dated as of December 21, 2007, by and among Helix Energy Solutions Group, Inc., the Guarantors and Wells Fargo Bank, N.A. incorporated by reference to Exhibit 4.1 to the registrants Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on December 21, 2007 (the “December 2007 8-K”).
10.1	1995 Long Term Incentive Plan, as amended, incorporated by reference to Exhibit 10.3 to the Form S-1.
10.2 *	Amendment to 1995 Long Term Incentive Plan of Helix Energy Solutions Group, Inc.
10.3	2009 Long-Term Incentive Cash Plan of Helix Energy Solutions Group, Inc., incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on January 6, 2009 (the “January 2009 8-K”).
10.4	Form of Award Letter related to the 2009 Long-Term Incentive Cash Plan, incorporated by reference to Exhibit 10.2 to the January 2009 8-K.

10.5	Employment Agreement between Owen Kratz and Company dated February 28, 1999, incorporated by reference to Exhibit 10.5 to the Annual Report for the fiscal year ended December 31, 1998, filed by the registrant with the Securities and Exchange Commission on March 31, 1999 (the “1998 Form 10-K”).
10.6	Employment Agreement between Owen Kratz and Company dated November 17, 2008, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on November 19, 2008 (the “November 2008 8-K”).
10.7	Employment Agreement between Martin R. Ferron and Company dated February 28, 1999, incorporated by reference to Exhibit 10.6 of the 1998 Form 10-K.
10.8	Employment Agreement between A. Wade Pursell and Company dated January 1, 2002, incorporated by reference to Exhibit 10.7 of the 2001 Form 10-K.
10.9	Helix 2005 Long Term Incentive Plan, including the Form of Restricted Stock Award Agreement, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on May 12, 2005.
10.10 *	Amendment to 2005 Long Term Incentive Plan of Helix Energy Solutions Group, Inc.
10.11	Employment Agreement by and between Helix and Bart H. Heijermans, effective as of September 1, 2005, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on September 1, 2005.
10.12	Employment Agreement between Bart H. Heijermans and Company dated November 17, 2008, incorporated by reference to Exhibit 10.2 to the November 2008 8-K.
10.13	Employment Agreement between Alisa B. Johnson and Company dated September 18, 2006, incorporated by reference to Exhibit 10.2 to the 2006 Form 10-Q.
10.14	Employment Agreement between Alisa B. Johnson and Company dated November 17, 2008, incorporated by reference to Exhibit 10.3 to the November 2008 8-K.
10.15	Employment Letter from the Company to Robert P. Murphy dated December 21, 2006, incorporated by reference to Exhibit 10.9 to the 2006 Annual Report (“2006 Form 10-K”).
10.16 *	Amendment to Employment Agreement between Robert P. Murphy and Company effective January 1, 2009, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on December 12, 2008.
10.17	Master Agreement between the Company and Cal Dive International, Inc. dated December 8, 2006, incorporated by reference to Exhibit 10.10 to the 2006 Form 10-K.
10.18	Tax Agreement between the Company and Cal Dive International, Inc. dated December 14, 2006, incorporated by reference to Exhibit 10.11 to the 2006 Form 10-K.
10.19	Registration Rights Agreement dated as of December 21, 2007 by and among Helix Energy Solutions Group, Inc., the Guarantors named therein and Banc of America Securities LLC, as representative of the Initial Purchasers, incorporated by reference to Exhibit 10.1 to December 2007 8-K.
10.20	Purchase Agreement dated as of December 18, 2007 by and among Helix Energy Solutions Group, Inc., the Guarantors named therein and Banc of America Securities LLC, and the other Initial Purchasers named therein incorporated by reference to Exhibit 10.2 to the December 2007 8-K.
10.21	Amendment No. 1 to Credit Agreement, dated as of November 29, 2007, by and among Helix, as borrower, Bank of America, N.A., as administrative agent, and the lenders named thereto incorporated by reference to Exhibit 10.3 to the December 2007 8-K.
10.22	Letter Agreement by and between Helix Energy Solutions Group, Inc. and Martin R. Ferron dated February 8, 2008 incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on February 8, 2008 (the “February 2008 8-K”).
10.23	

	Letter Agreement by and between Helix Energy Solutions Group, Inc. and Alan Wade Pursell dated June 25, 2008 incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on June 30, 2008 (the "June 2008 8-K").
10.24	Employment Agreement between Anthony Tripodo and the Company dated June 25, 2008, incorporated by reference to Exhibit 10.2 to the June 2008 8-K.

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10.25	First Amendment to Employment Agreement between Anthony Tripodo and the Company dated November 17, 2008, incorporated by reference to Exhibit 10.5 to the November 2008 8-K.
10.26	Consulting Agreement by and between A. Wade Pursell and the Company dated July 4, 2008, incorporated by reference to Exhibit 10.1 to the registrants Quarterly Report on Form 10-Q, filed by the registrant with the Securities and Exchange Commission on August 1, 2008.
10.27	Employment Agreement between Lloyd A. Hajdik and Company dated November 17, 2008, incorporated by reference to Exhibit 10.4 to the November 2008 8-K.
10.28	Stock Repurchase Agreement between Company and Cal Dive International, Inc. dated January 23, 2009, incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on January 28, 2009.
21.1*	List of Subsidiaries of the Company.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of Huddleston & Co., Inc.
31.1*	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer.
31.2*	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Anthony Tripodo, Chief Financial Officer
32.1**	Certification of Helix's Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes — Oxley Act of 2002

* Filed herewith.

** Furnished herewith.