HELIX ENERGY SOLUTIONS GROUP INC
Form 10-K/A
June 18, 2007

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
Form 10-K/A
Amendment No. 1

(Mark One)

þ **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the fiscal year ended December 31, 2006

or

o **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the transition period from __________ to __________

Commission File Number 001-32936
HELIX ENERGY SOLUTIONS GROUP, INC.
(Exact name of registrant as specified in its charter)

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

(281) 618 0400
(Registrant s telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
þ Yes o 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.
o Yes þ 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. þ Yes o 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. o

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

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2006 was $2,926,119,938 based on the last reported sales price of the Common Stock on June 30, 2006, as reported on the NASDAQ National Market System. On July 18, 2006, the registrant s Common Stock began trading on the New York Stock Exchange.

The number of shares of the registrant s Common Stock outstanding as of May 31, 2007 was 91,321,577.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement for the Annual Meeting of Shareholders held on May 7, 2007, are incorporated by reference into Part III hereof.

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EXPLANATORY NOTE

Helix Energy Solutions Group, Inc. (Helix) is filing this amendment to its Annual Report on Form 10-K for the fiscal year ended December 31, 2006 that was originally filed on March 1, 2007 (the Original 10-K) in response to comments received from the Securities and Exchange Commission s Division of Corporation Finance. This amendment includes the following:

Item 1A. *Risk Factors*, revised to change the title of the risk factor Estimates of our oil and gas reserves, future cash flows and abandonment costs may be significantly incorrect to 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 changes in those conditions, or other factors affecting those assumptions, could impair the quantity and value of our crude oil and natural gas reserves. We also deleted the word substantially from the fifth sentence of the applicable revised risk factor. We also expanded our risk factor Reserve replacement may not offset depletion;

Item 2. *Properties* Summary of Natural Gas and Oil Reserve Data, revised to add disclosures related to production, reserves, nature of our interest, location and status of development for our principal fields. We also enhanced our disclosures relating to the methodology used in the determination of proved reserves and the scope of the engineering audit by our independent petroleum engineers (Huddleston & Co., Inc. Huddleston);

Item 7. *Management s Discussion and Analysis of Financial Condition and results of Operation* Results of Operations, revised to indicate the direct operating expenses included in the breakout of our Oil and Gas operating expenses table includes production taxes. We also referenced our disclosures in our Critical Accounting Estimates and Policies relating to the engineering audit and the preparation of reserve data to Item 2; and

Item 8. *Financial Statements and Supplementary Data,* revised to provide enhanced disclosures relating to the methodology used in the determination of proved reserves and the scope of the engineering audit by our independent petroleum engineers.

Other than as specified above, this amendment does not modify or affect the financial statements or the notes thereto in the Original 10-K. This amendment does not reflect events occurring after the filing of the Original 10-K and does not modify or update the disclosures therein in any way other than as required to reflect the amendments as described above and set forth below. In accordance with Rule 12b-15 promulgated under the Securities Exchange Act of 1934, the complete text of each affected item, as amended, is included herein. Unaffected items have not been repeated in this amendment. Unless the statements indicate otherwise, as used in this amendment, the terms Company, we, us and our refer collectively to Helix and its subsidiaries.

Forward Looking Statements

The statements included or incorporated by reference in this amended Annual Report on Form 10-K for the year ended December 31, 2006 (this Annual Report) include forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included herein or incorporated herein by reference are forward-looking statements. Included among forward-looking statements are, among other things:

statements related to the volatility in commodity prices for oil and gas and in the supply of and demand for oil and natural gas or the ability to replace oil and gas reserves;

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; and

statements regarding any financing transactions or arrangements, or ability to enter into such transactions;

statements relating to the construction or acquisition of vessels or equipment and our proposed acquisition of any producing property or well prospect, including statements concerning the engagement of any engineering, procurement and construction contractor and any anticipated costs related thereto;

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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 or other financial items;

statements regarding our business strategy, our business plans or any other plans, forecasts or objectives, any or all of which are subject to change;

statements regarding any Securities and Exchange Commission 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 relating to our services or any statements related to the underlying assumptions related to any projection or forward-looking statement;

statements related to environmental risks, drilling and operating risks, or exploration and development risks and the ability of the combined company to retain key members of its senior management and key employees;

statements regarding general economic or political conditions, whether internationally, nationally or in the regional and local market areas in which we are doing business;

any other statements that relate to non-historical or future information.

These forward-looking statements are often identified by the use of terms and phrases such as achieve, anticipate, believe, estimate, expect, forecast, plan, project, propose, strategy, predict, envision, hope, ir potential, achieve, should, could and similar terms and phrases. Although we believe that the expectations reflected these forward-looking statements are reasonable, they do involve assumptions, risks and uncertainties, and these expectations may prove to be incorrect. You should not place undue reliance on these forward-looking statements.

Our actual results could differ materially from those anticipated in these forward-looking statements as a result of a variety of factors, including those discussed in Risk Factors below. 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 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 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;
- the discovery rate of new oil and gas reserves in offshore areas;
- technological advances affecting energy exploration, production, transportation and consumption;
- weather conditions;
- environmental and other governmental regulations, and
- tax policies.

The level of offshore construction activity improved somewhat in 2004 with the trend continuing through 2006, following higher commodity prices from 2003 to 2006 and significant damage sustained to the Gulf of Mexico infrastructure in Hurricanes *Katrina* and *Rita* in 2005. We cannot assure you that activity levels 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 such 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 the initial public offering of CDI, 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 our operating performance.

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

Marine operations conducted in the Gulf 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.

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, and the performance of third parties such as equipment suppliers. 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 a newbuild North Sea Vessel, the *Well Enhancer*;
- the conversion of the *Caesar* into a deepwater pipelay asset;
- the addition of a modular-based drilling system on the *Q4000*; and
- the construction of a minimal floating production unit to be utilized on the *Phoenix* field, the *Helix Producer I*, through a consolidated 50% owned variable interest entity.

Although the construction contracts provide for delay penalties, these projects are 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;
- 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 projects 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 & 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 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 depend on a number of additional factors, including commodity prices, market demand and the political, economic and regulatory climate.

Further, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment availability, failures or accidents;
- adverse weather conditions; and
- compliance with environmental and other governmental requirements, which may increase our costs or restrict our activities.

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

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

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

Oil and gas prices can fluctuate significantly and have a direct impact on our revenues. To manage our exposure to the risks inherent in such a volatile market, from time to time, we have 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 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 changes 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, 2006 and 2005, audited by our independent petroleum engineers. These reports rely upon various assumptions, including assumptions required by the Securities and Exchange Commission, 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

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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 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 Securities and Exchange Commission 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.

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 74% of our proved reserves at December 31, 2006 are PUDs and PDNP. Further, our proved producing reserves at December 31, 2006 are expected to experience annual decline rates averaging nearly 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, 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 prefer;

- due to their own liquidity and cash flow problems, delay the pace of 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.

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 oil and gas 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 departments issue rules and regulations to implement and enforce such laws that are often complex and costly to comply with and that carry

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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 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. Such environmental liability could substantially reduce our net income and could have a significant impact on our financial ability to carry out our oil and gas operations.

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.

Risks Relating to General Corporate Matters

We have higher levels of indebtedness after the acquisition of Remington in 2006.

As of December 31, 2006, we have approximately $1.5 billion of indebtedness outstanding. 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 general economic downturns, 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 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 will be reinvested under criteria defined by our credit agreements) .

If we fail to comply with the covenants and other restrictions in the agreements governing our debt, it could lead to an event of default and the acceleration of our repayment of outstanding debt. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions.

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 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.

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. We believe that our success and continued growth are also dependent upon our ability to attract and retain skilled personnel. We believe that our wage rates are competitive; however, unionization or a significant increase in the wages paid by other employers could result in a reduction in our workforce, increases in the wage rates we pay, or both. If either of these events occurs for any significant period of time, our revenues 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, and is expected to continue to place, 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.

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.

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 board of directors has 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 most of our senior officers that

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require cash payments in the event of a change of control. Any or all of the provisions or factors described above may have the effect of discouraging 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.

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.

As the initial public offering of CDI common stock was completed, in the future, we may not have the same access to services and equipment, as we had historically.

Although we have made arrangements to retain access to the services and equipment of CDI through certain inter-company agreements, it is possible that we will not have the same access to those services and equipment as we had historically, and as our ownership in CDI decreases over time, our access to such equipment and services could be further diminished.

Item 2. ***Properties.***

We own a fleet of 33 vessels (one of which was held-for-sale at December 31, 2006 and sold in January 2007) and 31 ROVs and trenchers. We also lease one vessel. 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 (thirteen of which are based in the Gulf of Mexico) have the capability to provide saturation diving services.

Divestitures in 2006

In December 2006, we contributed the assets of our Shelf Contracting segment into CDI, our then wholly owned subsidiary. CDI subsequently completed an initial public offering selling 22,173,000 shares of its common stock, which, together with shares issued to CDI employees immediately after the offering, reduced our ownership of CDI to 73.0%. CDI received net proceeds of $264.4 million from its initial public offering. All of the net proceeds were distributed to us as a dividend. In connection with the offering, CDI entered into a $250 million revolving credit facility. In December 2006, Cal Dive borrowed $201 million under the facility and distributed $200 million of the proceeds to us as a dividend. See Note 3 Initial Public Offering of Cal Dive International, Inc. in Item 8 for additional information.

Related to the Acergy acquisition, we entered into a consent order with the U.S. Department of Justice pursuant to which we agreed to divest three assets: the *Carrier*, the *Defender* and a portable saturation diving system acquired from Torch. As a result, these vessels were classified as held for sale at December 31, 2005. In 2006, we sold the portable saturation diving system and the *Defender*. As of December 31, 2006, the *Carrier* remained classified as held for sale. In January 2007, the *Carrier* was sold to an unrelated third-party. No gains or losses were recognized related to the sale.

Acquisitions in 2006

In January 2006, our wholly owned subsidiary, Vulcan Marine Technology LLC, acquired the *Caesar* (formerly known as the *Baron*), a four year old mono-hull vessel originally built for the cable lay market. The vessel was under charter to a third-party until mid January 2007. After the completion of the charter, the vessel was in transit to a shipyard in China where we plan to convert the vessel into a deepwater pipelay asset. The vessel is 485 feet long and already has a state-of-the-art, class 2, dynamic positioning system. The conversion program will primarily involve the installation of a conventional S lay pipelay system together with a main crane and a significant upgrade to the accommodation capability. A conversion team has already been assembled with a base at Rotterdam, the Netherlands, and the vessel is likely to enter service during the second half of 2007. The estimated cost to acquire and convert the vessel will be approximately $137.5 million. We have entered into an agreement with the third party currently leasing the vessel, whereby the third party has an option to purchase up to 49% of Vulcan for consideration totaling the proportionate share of the cost of the vessel plus the actual cost of conversion (conversion cost is estimated to be $110.0 million). The third party must make all contributions to Vulcan on or before March 31, 2007.

In January 2006, the *DLB 801* was acquired from Acergy. Subsequent to our purchase of the *DLB 801,* we sold a 50% interest in the vessel in January 2006 for approximately $19.0 million. The vessel is currently under a 10-year charter lease agreement with the purchaser of the 50% interest, in which the purchaser has an option to purchase the remaining 50% interest in the vessel beginning in January 2009. This lease was accounted for as an operating lease. In March 2006, we also acquired the *Kestrel* from Acergy.

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 stock and the assumption of $349.6 million of liabilities. The acquisition of Remington increased our oil and gas properties by approximately $860 million.

In addition, in July 2006, we acquired the business of Singapore-based Fraser Diving International Ltd for an aggregate purchase price of approximately $29.3 million, subject to post-closing adjustments, and the assumption of $2.2 million of liabilities. FDI owns 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 FDI 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. All of the assets acquired from FDI are included in our Shelf Contracting segment.

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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 the 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 mid-2008 in the *Phoenix* field (see below).

Further, in October 2006, we, along with Kommandor RØMØ A/S (Kommandor RØMØ), a Danish corporation, formed Kommandor, LLC (Kommandor), a Delaware limited liability company, to convert a ferry vessel into a dynamically-positioned minimal floating production system (see Production Facilities below). Kommandor qualified as a variable interest entity (VIE) under FASB Interpretation No. 46 *Consolidation of Variable Interest Entities* (FIN 46). We are the primary beneficiary of Kommandor. As a result, we have consolidated the results of Kommandor at December 31, 2006.

Also in October 2006, we acquired a 58% interest in Seatrac Pty Ltd. (Seatrac) 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 Seatrac shares (see Note 6 Other Acquisitions in Item 8. *Financial Statements and Supplementary Data* for a detailed discussion of Seatrac). We changed the name of the entity to Well Ops SEA Pty Ltd.

In December 2006, we acquired a 100% working interest in the *Camelot* oil field in the North Sea for the assumption of certain decommissioning liabilities totaling approximately $7.6 million. At December 31, 2006, *Camelot* had proved reserves of approximately 24 Bcfe. We have commenced existing field rejuvenation and expect first production in 2007. It is our intent to sell down to a 50% working interest prior to additional drilling or other large capital investments being made in the *Camelot* field area.

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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)
SHELF CONTRACTING (CAL DIVE INTERNATIONAL, INC.):							
Pipelay							
DLB 801[3]	Panama	1/2006	351	230	Capable	Anchor	815
Brave	U.S.	11/2005	275	80		Anchor	30 and 50
Rider	U.S.	11/2005	275	80		Anchor	50
Saturation Diving							
DP DSV *Eclipse*	Bahamas	3/2002	367	109	X	DP	5; 4.3; 92/43; 20.4 A-Frame
DP DSV *Kestrel*	Vanuatu	9/2006	323	80	X	DP	40; 15 ; 10; Hydralift HLR 308
DP DSV *Mystic Viking*	Bahamas	6/2001	253	60	X	DP	50
DP MSV *Uncle John*	Bahamas	11/1996	254	102	X	DP	2×100
DSV *American Constitution*	Panama	11/2005	200	46	X	4 point	20.41
DSV *Cal Diver I*	U.S.	7/1984	196	40	X	4 point	20
DSV *Cal Diver II*	U.S.	6/1985	166	32	X	4 point	40 A-Frame
DSV *Carrier* [4]	Vanuatu		270	36	Capable	4 point	
DSV Midnight Star[5]	Vanuatu	6/2006	197	42		4 point	20 and 40
Surface Diving							
American Diver	U.S.	11/2005	105	22			
American Liberty	U.S.	11/2005	110	22			1.588
Cal Diver IV	U.S.	3/2001	120	24			
DSV *American Star*	U.S.	11/2005	165	30		4 point	9.072
DSV *American Triumph*	U.S.	11/2005	164	32		4 point	13.61
DSV *American Victory*	U.S.	11/2005	165	34		4 point	9.072
DSV *Cal Diver V*	U.S.	9/1991	166	34		4 point	20 A-Frame
DSV *Dancer*	U.S.	3/2006	173	34		4 point	30
DSV *Mr. Fred*	U.S.	3/2000	166	36		4 point	25
Fox	U.S.	10/2005	130	42			
Mr. Jack	U.S.	1/1998	120	22			10
Mr. Jim	U.S.	2/1998	110	19			
Polo Pony	U.S.	3/2001	110	25			
Sterling Pony	U.S.	3/2001	110	25			
White Pony	U.S.	3/2001	116	25			
CONTRACTING SERVICES:							

Pipelay							
Caesar[(6)]	Vanuatu	1/2006	482	220		DP	300 and 36
Express	Vanuatu	8/2005	520	132		DP	500 and 120
Intrepid	Bahamas	8/1997	381	50		DP	400
Talisman	U.S.	11/2000	195	14			
Well Operations							
Q4000[(7)]	U.S.	4/2002	312	135	Capable	DP	160 and 360; 600 Derrick
Seawell	U.K.	7/2002	368	129	X	DP	130
Robotics							
27 ROVs and 4 Trenchers[(8)]		Various					
Northern Canyon[(9)]	Bahamas	6/2002	276	58		DP	50
			12				

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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 American Bureau of Shipping, or ABS, Bureau Veritas, or BV, Det Norske Veritas, or DNV, Lloyds Register of Shipping, or Lloyds, and the U.S. Coast Guard, or 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) The *DLB 801* was purchased in January 2006 and a 50% interest in the vessel was subsequently sold to an unaffiliated purchaser that same month. The vessel is now under a 10-year charter lease agreement with the purchaser of the 50% interest. The charter lease agreement includes an option by the purchasers to purchase our 50% interest in the vessel beginning in January 2009.

(4) Held for sale at December 31, 2006. The vessel was sold in January 2007.

(5) Expected to be converted in the second or third quarter of 2007 to full saturation diving capabilities.

(6) Currently under conversion into a deepwater pipelay asset by late 2007.

(7) Expected to add drilling capabilities on the vessel in mid-2007.

(8) Average age of our fleet of ROVs and trenchers is approximately 4.01 years.

(9) Leased.

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, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	**2005**	**2004**
Contracting Services:			
Pipelay	86%	86%	72%
Well operations	81%	84%	80%
ROVs	71%	69%	51%
Shelf Contracting	84%	65%	52%

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. The *Q4000* is subject to a mortgage that secures the MARAD financing guarantees as described in Item 8. *Financial Statements and Supplementary Data* Note 10 Long-term Debt.

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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 (140 fields as of December 31, 2006). 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 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 they had satisfactorily resolved their 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 performed 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 a percentage 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 83% of the total discounted future net revenues. Huddleston audited approximately 81% of our total reserve base in the United States, including what was deemed to be the most valuable properties. Huddleston audited 76% of proved developed reserves and 85% of the proved undeveloped reserves totaling 81% of both categories combined. 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 they believe 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.

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The table below sets forth information, as of December 31, 2006, 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, 2006		
	Proved Developed Reserves	Proved Undeveloped Reserves	Total Proved Reserves
United States:			
Gas (Bcf)	156	138	294
Oil (MMBbls)	13	23	36
Total (Bcfe)	236	276	512
United Kingdom:			
Gas (Bcf)		24	24
Oil (MMBbls)			
Total (Bcfe)		24	24
Total:			
Gas (Bcf)	156	162	318
Oil (MMBbls)	13	23	36
Total (Bcfe)	236	300	536

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 20 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, 2006, 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. This is our only oil and gas property in the United Kingdom.

Our U.S. operations accounted for 100% of our 2006 production and approximately 96% of total proved reserves at December 31, 2006 (74% of such total reserves are PUDs and PDNP). Further, our proved producing reserves at December 31, 2006 are expected to experience annual decline rates averaging nearly 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, 2006:

	Development Location	Net Total Proved Reserves (Bcfe)	Net Proved Reserves Mix Oil%	Net Proved Reserves Mix Gas %	2006 Net Production (Bcfe)	Average WI%	Expected First Production
United States Offshore:							
Deepwater							
Phoenix(1)	U.S. GOM	47	79%	21%		100%	2008
Tiger(2)	U.S. GOM	13		100%		40%	Producing
Gunnison(3)	U.S. GOM	31	46%	54%	10	19%	Producing
Bass Lite(4)	U.S. GOM	18		100%		17.5%	2008
Devil s Island(5)	U.S. GOM	21	73%	27%		94%	2008
Outer Continental Shelf							
East Cameron 346	U.S. GOM	43	80%	20%	3	75%	Producing
West Cameron 170	U.S. GOM	25	28%	72%	1	55%	Producing
South Marsh Island 130	U.S. GOM	16	72%	28%	6	100%	Producing
South Timbalier 86/63	U.S. GOM	24	47%	53%	3	95%	Producing
United States Onshore:							
Parker Creek	Mississippi	17	99%	1%	1	67%	Producing
United Kingdom Offshore(6)	UK Offshore	24		100%		100%	2007

(1) Green Canyon blocks 236, 237, 238 and 282.

(2) Green Canyon block 195.

(3) An outside operated property comprised of Garden Banks

blocks 625, 667, 668 and 669.

(4) Atwater Valley block 426.

(5) Garden Banks block 344.

(6) Consists of our only property in the United Kingdom, *Camelot*.

United States Offshore

Deepwater

We have proved reserves of approximately 130 Bcfe in five fields in the Gulf of Mexico Deepwater which comprised approximately 24% of our total proved reserves as of December 31, 2006. The working interests in these fields range from 17.5% to 100%. We are the operator of two of the five fields, which comprised approximately 52% of our Deepwater proved reserves (approximately 13% of total proved reserves). *Gunnison* has been producing since December 2003. The *Tiger* field began production in late December 2006. Our net production in Deepwater totaled approximately ten Bcfe in 2006. We continue to be active in Deepwater with an ongoing exploration and development program.

Outer Continental Shelf

We have proved reserves of approximately 358 Bcfe in over 100 fields in the Gulf of Mexico on the OCS which comprised approximately 67% of total proved reserves as of December 31, 2006. Our net production on the OCS totaled approximately 38 Bcfe in 2006. The working interests in our OCS fields range from 3% to 100%. Our largest field based on proved reserves is East Cameron 346, with approximately 12% of OCS reserves (approximately 8% of total proved reserves). No other individual OCS field comprised over 5% of total proved reserves. We are the operator of 52% of our OCS proved reserves. We continue to be active on the OCS with an ongoing exploration and development program. Based on current market conditions, we plan to drill over 20 wells on the OCS in 2007.

United States Onshore

We have proved reserves of approximately 24 Bcfe in over 20 onshore fields in Mississippi, Alabama, Louisiana and Texas, with net production totaling approximately one Bcfe in 2006. Our U.S. onshore proved reserves comprised approximately 4% of total proved reserves as of December 31, 2006. The working interests in our onshore properties range from 7% to 94%. We are not the operator of most of the onshore fields. One onshore non-operated field *(Parker Creek*) in Mississippi comprised over 70% of our U.S. onshore reserves, but only approximately 3% of our total proved reserves. There are no significant developments scheduled for the onshore fields.

United Kingdom Offshore

In December 2006, we acquired the *Camelot* field (100%), located in the North Sea. This is our only oil and gas property in the United Kingdom.

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,		
	2006	**2005**	**2004**
Production:			
Gas (Bcf)	28	18	26
Oil (MMBbls)	3	3	3
Total (Bcfe)	48	33	42
Average sales prices realized (including hedges):			
Gas (per Mcf)	$ 7.86	$ 8.08	$ 5.76
Oil (per Bbl)	$ 60.41	$ 49.15	$ 33.92
Total (per Mcfe)	$ 8.79	$ 8.13	$ 5.72
Average production cost per Mcfe	$ 1.85	$ 1.71	$ 0.95
Average depletion and amortization per Mcfe	$ 2.79	$ 2.14	$ 1.66

As we acquired *Camelot* in December 2006 (which was not then producing), we had no oil and gas production in the United Kingdom in 2006.

Productive Wells

The number of productive oil and gas wells in which we held interest as of December 31, 2006 is as follows:

		Oil Wells		Gas Wells		Total Wells	
		Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States	Offshore	145	107	155	71	300	178
United States	Onshore	24	8	75	15	99	23
Total		169	115	230	86	399	201

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.

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The following table summarizes non-producing wells as of December 31, 2006. Included in non-producing wells are productive wells awaiting additional action, pipeline connections or shut-in for various reasons.

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Not producing (shut-in)	267	205	299	141	566	346

Developed and Undeveloped Acreage

The developed and undeveloped acreage (including both leases and concessions) that we held at December 31, 2006 is as follows:

	Undeveloped		Developed	
	Gross	Net	Gross	Net
United States				
Offshore	625,100	393,870	711,189	378,731
Onshore	9,470	6,956	20,914	7,040
Total United States	634,570	400,826	732,103	385,771
United Kingdom offshore	34,842	34,842		
Total	669,412	435,668	732,103	385,771

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 (acreage):

	Offshore		Onshore		Total	
	Gross	Net	Gross	Net	Gross	Net
2007	156,732	70,872	3,708	2,490	160,440	73,362
2008	144,461	79,876	4,292	2,996	148,753	82,872
2009	114,729	74,682	1,470	1,470	116,199	76,152
2010	105,966	80,652			105,966	80,652
Total	521,888	306,082	9,470	6,956	531,358	313,038

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, 2006, 2005 and 2004:

Net Exploratory Wells			Net Development Wells		
Productive	Dry	Total	Productive	Dry	Total
6.5	2.1	8.6	4.6		4.6

Year ended December 31, 2006				
Year ended December 31, 2005	0.4	0.4	1.2	1.2
Year ended December 31, 2004	1.3	1.3	1.1	1.1

As we acquired *Camelot* in December 2006, no wells were drilled in the United Kingdom in 2006.

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

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

At December 31, 2006, our oil and gas operations were drilling 2 gross (0.6 net) development wells and 6 gross (4 net) exploration wells, and 0.4 net suspended exploratory wells. These wells are located in the Gulf of Mexico. The drilling cost to us for these wells will be approximately $104.2 million if all are dry and approximately $163.4 million if all are completed as producing wells.

PRODUCTION FACILITIES

Through our interest in Deepwater Gateway, L.L.C., 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, L.L.C. 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, LLC, an affiliate of Enterprise Products Partners L.P., that will own the Independence Hub platform, a 105 foot deep draft, semi-submersible platform to be located in Mississippi Canyon block 920 in a water depth of 8,000 feet that will serve as a regional hub for natural gas production from multiple ultra-Deepwater fields in the previously untapped eastern Gulf of Mexico. Installation of the platform is scheduled for the first quarter of 2007 and first production is expected in mid-2007. The Independence Hub facility will be capable of processing 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, 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, in October 2006, we invested $15 million for a 50% interest in Kommandor to convert a ferry vessel into a dynamically-positioned minimal floating production system. Upon completion of the initial conversion, this vessel will be leased under a bareboat charter to us for further conversion and subsequent use as a floating production system in the Deepwater Gulf of Mexico, initially for the *Phoenix* field. Conversion of the vessel is expected to be completed in two phases. The first phase is expected to be completed by the end of 2007 for approximately $60 million. The second phase of the conversion is expected to be completed by mid-2008. Estimated cost of conversion for the second phase is approximately $100 million, of which we expect to fund 100%.

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FACILITIES

Our corporate headquarters are located at 400 N. Sam Houston Parkway E., Suite 400, Houston, Texas. Our primary subsea and marine services operations are based in Port of Iberia, Louisiana. We own the Aberdeen (Dyce), Scotland facility. All of our 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 Cal Dive International, Inc. Corporate Headquarters, Project Management, and Sales Office Energy Resource Technology GOM, Inc. Corporate Headquarters Well Ops Inc. Corporate Headquarters, Project Management, and Sales Office Kommandor LLC[1] Corporate Headquarters	85,000 square feet
Houston, Texas	Canyon Offshore, Inc. Corporate, Management and Sales Office	27,000 square ft.
Dallas, Texas	Energy Resource Technology GOM, Inc. Dallas Office	25,000 square ft.
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	12,916 square feet
Aberdeen (Dyce), Scotland	Well Ops (U.K.) Limited Corporate Offices and Operations Canyon Offshore Limited Corporate Offices, Operations and Sales Office	3.9 acres (Building: 42,463 square ft.)
Aberdeen (Westhill), Scotland	Helix RDS Limited Corporate Offices	11,333 square ft.

	ERT (UK) Limited Corporate Offices	
London, England	Helix RDS Limited Corporate Offices	3,365 square ft.
Kuala Lumpur, Malaysia	Helix RDS Sdn Bhd Corporate Offices	2,227 square ft.
Perth, Australia	Cal Dive International, Inc. (2) Operations, Offices and Project Management	28,738 square feet
Perth, Australia	Well Ops SEA Pty Ltd(3) Corporate Offices	1.0 acre (Building: 12,040 square feet)

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Location	Function	Size
Perth, Australia	Helix RDS Pty Ltd Corporate Offices Helix ESG Pty Ltd. Corporate Offices	8,202 square ft.
Rotterdam, The Netherlands	Helix Energy Solutions BV Corporate Offices	6,620 square ft.
Singapore	Cal Dive International, Inc. (2) Marine, Operations, Offices, Project Management and Warehouse	29,772 square feet
Singapore	Canyon Offshore International Corp Corporate, Operations and Sales Well Ops PTE Ltd Corporate Headquarters	13,180 square ft.

(1) Kommandor LLC is a joint venture in which we owned 50% at December 31, 2006. Kommandor is included in our consolidated results as of December 31, 2006.

(2) Cal Dive International, Inc. is our Shelf Contracting subsidiary, of which we owned 73.0% at December 31, 2006.

(3) At December 31, 2006, we owned 58% of Well Ops SEA Pty Ltd.

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PART II

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

The following management discussion and analysis should be read in conjunction with our historical consolidated financial statements and their notes included elsewhere in this report. This discussion 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 Risk Factors and elsewhere in this report.

Executive Summary

Our Business

We are an international offshore energy company that provides development solutions and other key services to the open 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 (F&D) costs, relative to industry norms.

Industry Overview and Major Influences

The offshore oil and gas industry originated in the early 1950s as producers began to explore and develop the new frontier of offshore fields. The industry has grown significantly since the 1970s with service providers taking on greater roles on behalf of the producers. Industry standards were established during this period largely in response to the emergence of the North Sea as a major province leading the way into a new hostile frontier. The methodology of these standards was driven by the requirement of mitigating the risk of developing relatively large reservoirs in a then challenging environment. These standards are still largely adhered to today for all developments even if they are small and the frontier is more understood. There are factors we believe will influence the industry in the coming years: (1) Increasing world demand for oil and natural gas; (2) global production rates peaking; (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; and (7) increasing number of subsea developments.

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 expenditure 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;
- 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;
- the discovery rate of new oil and gas reserves in offshore areas;

technological advances affecting energy exploration production transportation and consumption;

weather conditions;

environmental and other governmental regulations; and

tax policies.

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Activity Summary

Over the last few years we continued to evolve the Helix model by completing a variety of transactions and events which 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 and Acergy for a combined purchase price of $210.2 million. We also acquired a significant mature property package on 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 Tech Services group through the acquisition of Helix Energy Limited (Helix RDS) for $32.7 million. In 2006, we acquired Remington, an exploration, development and production company, for approximately $1.4 billion in cash and stock and the assumption of $349.6 million of liabilities. We changed our name from Cal Dive International, Inc. to Helix Energy Solutions Group, Inc., leaving the Cal Dive name in our diving subsidiary, and in December 2006 completed a carve-out IPO of that company selling a 26.5% stake receiving pre-tax net proceeds of $264.4 million from CDI and a pre-tax dividend of $200 million from CDI s revolver. We acquired the *Caesar*, a 485 foot cable lay vessel which we intend to convert into a Deepwater pipelay asset (total acquisition plus estimated conversion cost is $137.5 million). We also acquired a 100% interest in the *Phoenix* field (formerly known as *Typhoon*) where we expect to deploy a minimal floating production system in mid-2008. We also expanded our subsea well intervention services in Australia through the acquisition of 58% of Seatrac. Finally, we moved our stock listing from Nasdaq (HELX) to the New York Stock Exchange (HLX) in July 2006.

In February 2007, we announced an update on drilling activity at our 100% owned *Noonan* prospect on Garden Banks Block 506 in 2,700 feet of water. Since operations commenced in October 2006, we have completed the drilling of an exploratory well and two appraisal sidetracks. Formation evaluation from wireline logs, pressure analysis and sidewall cores have successfully delineated our reservoir for completion of the well.

Results of Operations

Our operations are conducted through the following lines of businesses: contracting services operations and oil and gas operations. We have disaggregated our contracting services operations into three reportable segments in accordance with SFAS 131. As a result, our reportable segments consist of the following: Contracting Services (formerly known as Deepwater Contracting), Shelf Contracting, Oil and Gas (formerly known as Oil and Gas Production) and Production Facilities. Contracting Services operations include services such as deepwater pipelay, well operations, robotics and reservoir and well tech services. Shelf Contracting operations consist of assets deployed primarily for diving-related activities and shallow water construction. See Item 8. *Financial Statements and Supplementary* Data Note 3 Initial Public Offering of Cal Dive International, Inc. for discussion of initial public offering of CDI common stock (represented by the Shelf Contracting segment). All material intercompany transactions between the segments have been eliminated in our consolidated results of operations.

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Comparison of Years Ended 2006 and 2005

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

	Year Ended December 31, 2006	2005	Increase/ (Decrease)
Revenues (in thousands)			
Contracting Services	$ 485,246	$ 328,315	$ 156,931
Shelf Contracting	509,917	223,211	286,706
Oil and Gas	429,607	275,813	153,794
Intercompany elimination	(57,846)	(27,867)	(29,979)
	$ 1,366,924	$ 799,472	$ 567,452
Gross profit (in thousands)			
Contracting Services	$ 138,516	$ 69,381	$ 69,135
Shelf Contracting	222,530	71,215	151,315
Oil and Gas	162,386	142,476	19,910
Intercompany elimination	(8,024)		(8,024)
	$ 515,408	$ 283,072	$ 232,336
Gross Margin			
Contracting Services	29%	21%	8 pts
Shelf Contracting	44%	32%	12 pts
Oil and Gas	38%	52%	(14) pts
Total company	38%	35%	3 pts
Number of vessels(1)/ Utilization(2)			
Contracting Services:			
Pipelay	3/86%	2/86%	
Well operations	2/81%	2/84%	
ROVs	32/71%	30/69%	
Shelf Contracting	25/84%	23/65%	

(1) 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.

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

Intercompany segment revenues during the years ended December 31, 2006 and 2005 were as follows (in thousands):

	Year Ended December 31, 2006	Year Ended December 31, 2005	Increase/ (Decrease)
Contracting Services	$ 42,585	$ 26,431	$ 16,154
Shelf Contracting	15,261	1,436	13,825
	$ 57,846	$ 27,867	$ 29,979

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Intercompany segment profit (which only relates to intercompany capital projects) during the years ended December 31, 2006 and 2005 were as follows (in thousands):

	Year Ended December 31, 2006	Year Ended December 31, 2005	Increase/ (Decrease)
Contracting Services	$ 2,460	$	$ 2,460
Shelf Contracting	5,564		5,564
	$ 8,024	$	$ 8,024

The following table details various financial and operational highlights related to our oil and gas operations for the periods presented:

	Year Ended December 31, 2006	Year Ended December 31, 2005	Increase/ Decrease
Oil and Gas information			
Oil production volume (MBbls)	3,400	2,473	927
Oil sales revenue (in thousands)	$ 205,415	$ 121,510	$ 83,905
Average oil sales price per Bbl (excluding hedges)	$ 61.08	$ 51.87	$ 9.21
Average realized oil price per Bbl (including hedges)	$ 60.41	$ 49.15	$ 11.26
Increase in oil sales revenue due to:			
Change in prices (in thousands)	$ 27,840		
Change in production volume (in thousands)	56,065		
Total increase in oil sales revenue (in thousands)	$ 83,905		
Gas production volume (MMcf)	27,949	18,137	9,812
Gas sales revenue (in thousands)	$ 219,674	$ 146,591	$ 73,083
Average gas sales price per mcf (excluding hedges)	$ 7.46	$ 8.48	$ (1.02)
Average realized gas price per mcf (including hedges)	$ 7.86	$ 8.08	$ (0.22)
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$ (4,018)		
Change in production volume (in thousands)	77,101		
Total increase in gas sales revenue (in thousands)	$ 73,083		
Total production (MMcfe)	48,349	32,975	15,374
Price per Mcfe	$ 8.79	$ 8.13	$ 0.66

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 this basis with barrels of oil converted to Mcfe at a ratio of one barrel to six Mcf:

	Year Ended December 31,			
	2006		2005	
	Total	Per Mcfe	Total	Per Mcfe
Oil and gas operating expenses[1]:				
Direct operating expenses[2]	$ 50,930	$ 1.05	$ 26,997	$ 0.82
Workover	11,462	0.24	9,668	0.29
Transportation	3,174	0.07	3,814	0.12
Repairs and maintenance	13,081	0.27	6,030	0.18
Overhead and company labor	10,492	0.22	9,726	0.30
Total	$ 89,139	$ 1.85	$ 56,235	$ 1.71
Depletion and amortization	$ 134,967	$ 2.79	$ 70,637	$ 2.14

(1) Excludes exploration expense of $43.1 million and $6.5 million for the years ended December 31, 2006 and 2005, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

Revenues. During the year ended December 31, 2006, our revenues increased by 71% as compared to 2005. Contracting Services revenues increased primarily due to improved market demand (resulting in improved contract pricing for the Pipelay, Well Operations and ROV divisions), and the addition of the *Express* acquired from Torch in 2005 and Helix Energy Limited acquired in 2005. Shelf Contracting revenue increased due to the additional vessels acquired from Acergy and Torch during 2005 and improved market demand, much of which was the result of damages sustained in the 2005 hurricanes in the Gulf of Mexico. This resulted in significantly improved utilization rates and an overall increase in pricing for our Shelf Contracting services.

Oil and Gas revenue increased 56%, during 2006 compared with the prior year. The increase was primarily due to increases in oil and natural gas production. The production volume increase of 47% over 2005 was mainly attributable to the full second half impact of the Remington acquisition, partially offset by continued pipeline shut-ins on certain fields. Oil and Gas revenue also increased due to higher oil prices realized in 2006 as compared to 2005, offset slightly by a $0.22 decline in average realized gas prices.

Gross Profit. Gross profit in 2006 increased 82% as compared to the same period in 2005. The Contracting Services gross profit increase was primarily attributable to improved contract pricing for the Pipelay, Well Operations and ROV divisions, and the addition of the *Express*. The gross profit increase within Shelf Contracting was primarily attributable to additional gross profit derived from the Torch and Acergy acquisitions, improved utilization rates and increased contract pricing as discussed above.

Oil and Gas gross profit increased 14% in 2006 compared to 2005. Gross profit was negatively impacted by $43.1 million of exploration costs incurred during 2006 compared with $6.5 million incurred in 2005. The increase in exploration costs was primarily due to dry hole costs of $21.7 million related to the Tulane prospect as a result of mechanical difficulties experienced in the drilling of this well. The well was subsequently plugged and abandoned in the first quarter of 2006. In addition, we incurred dry hole costs totaling approximately $15.9 million in the third quarter of 2006 associated with two deep shelf wells commenced by Remington prior to the acquisition. We expensed inspection and repair costs of approximately $16.8 million as a result of Hurricanes *Katrina* and *Rita*, partially offset by $9.7 million in insurance recoveries in 2006 compared to $7.1 million of hurricane inspection and repair costs in 2005. In addition, depletion and amortization per Mcfe increased 30% in 2006 compared to 2005 due primarily to the acquisition costs associated with the Remington properties acquired in July 2006. These decreases were offset by higher oil prices realized and higher oil and gas production as discussed above. In addition, in 2005 we recorded $2.7 million of losses associated with hedge instrument ineffectiveness

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as a result of production shut-ins caused by the aforementioned hurricanes. No hedge ineffectiveness was recorded in 2006.

Selling and Administrative Expenses. Selling and administrative expenses of $119.6 million were $56.8 million higher than the $62.8 million incurred in 2005. The increase was due primarily to higher overhead to support our growth. Selling and administrative expenses increased slightly to 9% of revenues in 2006 compared to 8% in 2005.

Equity in Earnings of Investments. Equity in earnings of our 50% investment in Deepwater Gateway, L.L.C. increased to $18.4 million in 2006 compared with $10.6 million in 2005 due to increased throughput at the *Marco Polo* TLP. Further, equity losses in our 40% minority ownership interest in OTSL for 2006 totaled approximately $487,000 compared with equity earnings of $2.8 million in 2005.

Gain on Subsidiary Equity Transaction**.** Gain on subsidiary equity transaction of $223.1 million is related to the CDI initial public offering of 22,173,000 shares of its common stock in December 2006, together with shares issued to CDI employees immediately after the offering, our ownership reduced to 73.0%. CDI received net proceeds of $264.4 million from its initial public offering. Together with CDI s drawdown of its revolving credit facility, CDI paid pre-tax dividends of $464.4 million to us in December 2006. The gain is as a result of these transactions.

Net Interest Expense and Other. We reported interest and other expense of $34.6 million in 2006 compared to $7.6 million in the prior year. Gross interest expense of $51.9 million during 2006 was higher than the $15.0 million incurred in 2005. Approximately $31.4 million of the increase was related to our Term Loan which closed in July 2006 and $2.4 million of the increase was related to our $300 million Convertible Senior Notes which closed in March 2005. Offsetting the increase in interest expense was $10.6 million of capitalized interest in 2006, compared with capitalized interest of $2.0 million in the prior year.

Provision for Income Taxes. Income taxes increased to $257.2 million in 2006 compared to $75.0 million in the prior year. $126.6 million of the income tax expense increase was related to the CDI dividends to us. The remaining increase was primarily due to increased profitability. The effective tax rate of 42.5% for 2006 was higher than the 33.0% effective tax rate for same period in 2005 due primarily to the CDI dividends of $464.4 million received in December 2006.

Comparison of Years Ended 2005 and 2004

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

	Year Ended December 31, 2005	Year Ended December 31, 2004	Increase/ (Decrease)
Revenues (in thousands)			
Contracting Services	$ 328,315	$ 197,688	$ 130,627
Shelf Contracting	223,211	126,546	96,665
Oil and Gas	275,813	243,310	32,503
Intercompany elimination	(27,867)	(24,152)	(3,715)
	$ 799,472	$ 543,392	$ 256,080
Gross profit (in thousands)			
Contracting Services	$ 69,381	$ 11,142	$ 58,239
Shelf Contracting	71,215	25,516	45,699
Oil and Gas	142,476	135,427	7,049
Intercompany elimination		(173)	173
	$ 283,072	$ 171,912	$ 111,160
Gross Margin			
Contracting Services	21%	6%	15 pts
Shelf Contracting	32%	20%	12 pts
Oil and Gas	52%	56%	(4)pts
Total company	35%	32%	3 pts
Number of vessels(1)/ Utilization(2)			
Contracting Services:			
Pipelay	2/86%	1/72%	
Well operations	2/84%	2/80%	
ROVs	30/69%	22/51%	
Shelf Contracting	23/65%	17/52%	

(1) 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.

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

Intercompany segment revenues during the years ended December 31, 2005 and 2004 were as follows (in thousands):

	Year Ended December 31,		Increase/
	2005	**2004**	**(Decrease)**
Contracting Services	$ 26,431	$ 22,246	$ 4,185
Shelf Contracting	1,436	1,906	(470)
	$ 27,867	$ 24,152	$ 3,715

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Intercompany segment profit (which only relates to intercompany capital projects) during the years ended December 31, 2005 and 2004 were as follows (in thousands):

	Year Ended December 31,		
	2005	2004	Increase/ (Decrease)
Contracting Services	$	$ 91	$ (91)
Shelf Contracting		82	(82)
	$	$ 173	$ (173)

The following table details various financial and operational highlights related to our oil and gas operations for the periods presented:

	Year Ended December 31,		
	2005	2004	Increase/ (Decrease)
Oil and Gas information			
Oil production volume (MBbls)	2,473	2,593	(120)
Oil sales revenue (in thousands)	$ 121,510	$ 87,951	$ 33,559
Average oil sales price per Bbl (excluding hedges)	$ 51.87	$ 38.05	$ 13.82
Average realized oil price per Bbl (including hedges)	$ 49.15	$ 33.92	$ 15.23
Increase (decrease) in oil sales revenue due to:			
Change in prices (in thousands)	$ 37,664		
Change in production volume (in thousands)	(4,105)		
Total increase in oil sales revenue (in thousands)	$ 33,559		
Gas production volume (MMcf)	18,137	25,957	(7,820)
Gas sales revenue (in thousands)	$ 146,591	$ 149,395	$ (2,804)
Average gas sales price per mcf (excluding hedges)	$ 8.48	$ 5.77	$ 2.71
Average realized gas price per mcf (including hedges)	$ 8.08	$ 5.76	$ 2.32
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$ 42,078		
Change in production volume (in thousands)	(44,882)		
Total decrease in gas sales revenue (in thousands)	$ (2,804)		
Total production (MMcfe)	32,975	41,515	(8,540)
Price per Mcfe	$ 8.13	$ 5.72	$ 2.41

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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 this basis with barrels of oil converted to Mcfe at a ratio of one barrel to six Mcf:

	Year Ended December 31,			
	2005		2004	
	Total	Per Mcfe	Total	Per Mcfe
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$ 26,997	$ 0.82	$ 19,030	$ 0.46
Workover	9,668	0.29	3,111	0.07
Transportation	3,814	0.12	3,898	0.09
Repairs and maintenance	6,030	0.18	5,173	0.12
Overhead and company labor	9,726	0.30	8,198	0.21
Total	$ 56,235	$ 1.71	$ 39,410	$ 0.95
Depletion and amortization	$ 70,637	$ 2.14	$ 69,046	$ 1.66

(1) Excludes exploration expense of $6.5 million for the year ended December 31, 2005. We had no exploration expenses in 2004. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

Revenues. During the year ended December 31, 2005, our revenues increased 47% as compared to the same period in 2004. Our Contracting Services revenues increase was due primarily to improved market demand resulting in significantly improved utilization rates and contracting pricing for all divisions within the segment (deepwater, well operations and ROVs). The Shelf Contracting revenues increase was also due to improved market demand, much of which was the result of damages sustained in Hurricanes *Katrina* and *Rita.* This resulted in significantly improved utilization rates and contract pricing for all divisions within the segment (shallow water pipelay, diving and portable SAT systems). Further, Shelf Contracting s revenues increased in 2005 compared with 2004 directly as a result of the acquisition of the Torch and Acergy vessels in the third and fourth quarter of 2005, with much of the impact attributable to the fourth quarter.

The increase in our Oil and Gas revenue for the year ended December 31, 2005 was primarily due to increase in average price realized. These increases were partially offset by lower production primarily as a result of production shut-ins due to Hurricanes *Katrina* and *Rita* in the third and fourth quarters of 2005.

Gross Profit. Gross profit in 2005 increased 65% as compared to 2004. The Contracting Services gross profit increase was primarily attributable to improved utilization rates and contract pricing for all divisions within the segment. Gross profit for the Shelf Contracting segment also increased as a result of improved utilization rates and contract pricing for all divisions within the segment. In addition, our Shelf Contracting segment recorded asset impairments on certain vessels totaling $790,000 in 2005 as compared to $3.9 million in 2004 for conditions meeting our asset impairment criteria.

Our Oil and Gas gross profit increase was due to the aforementioned higher commodity price increases, offset by decreased production levels. Further, in 2005, gross profit for the Oil and Gas segment was also negatively impacted by impairment analysis on certain properties and expensed well work which resulted in $4.8 million of impairments, inspection and repair costs of approximately $7.1 million as a result of Hurricanes *Katrina* and *Rita* (no insurance recoveries were recorded as of December 31, 2005), and $5.7 million of expensed seismic data purchased for our offshore property acquisitions.

Selling & Administrative Expenses. Selling and administrative expenses of $62.8 million for the year ended December 31, 2005 were $13.9 million higher than the $48.9 million incurred in 2004 due primarily to increased incentive compensation as a result of increased profitability. Selling and administrative expenses at 8% of revenues for 2005 was slightly lower than the 9% of revenues in 2004.

Equity in Earnings of Investments. Equity in earnings of our 50% investment in Deepwater Gateway increased to $10.6 million in 2005 compared with $7.9 million in 2004. The increase was attributable to the demand fees which commenced following the March 2004 mechanical completion of the *Marco Polo* tension leg platform, owned by Deepwater Gateway, as well as production tariff charges which commenced in the third quarter of 2004 as *Marco Polo* began producing. Further, equity in earnings from our 40% minority ownership interest in OTSL in 2005 totaled approximately $2.8 million. We acquired our interest in OTSL in July 2005.

Other (Income) Expense. We reported other expense of $7.6 million for the year ended December 31, 2005 compared to other expense of $5.3 million for the year ended December 31, 2004. Net interest expense of $7.0 million in 2005 was higher than the $5.6 million incurred in 2004 due primarily to higher levels of debt associated with our $300 million Convertible Senior Notes which closed in March 2005. Offsetting the increase in interest expense was $2.0 million of capitalized interest in 2005, compared with $243,000 in 2004, which related to our investment in *Gunnison* and Independence Hub, and interest income of $5.5 million in 2005 compared to $439,000 in 2004.

Income Taxes. Income taxes increased to $75.0 million for the year ended December 31, 2005 compared to $43.0 million in 2004, primarily due to increased profitability. The effective tax rate of 33% in 2005 was lower than the 34% effective tax rate for 2004 due to our ability to realize foreign tax credits and oil and gas percentage depletion due to improved profitability both domestically and in foreign jurisdictions, and implementation of the Internal Revenue Code section 199 manufacturing deduction as it primarily related to oil and gas production. In 2004, we recognized a benefit for our research and development credits in the first quarter of 2004 as a result of the conclusion of the Internal Revenue Service (IRS) examination of our income tax returns for 2001 and 2002, and the tax cost or benefit of U.S. and U.K. branch operations.

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):

	2006	2005
Net working capital	$ 310,524	$120,388
Long-term debt(1)	1,454,469	440,703

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

	Year Ended December 31,		
	2006	2005	2004
Net cash provided by (used in):			
Operating activities	$ 514,036	$ 242,432	$ 226,807
Investing activities	$(1,379,930)	$(499,925)	$(132,562)
Financing activities	$ 978,260	$ 288,066	$ (40,037)

Our primary cash needs are to fund capital expenditures to allow the growth of our current lines of business and to repay outstanding borrowings and make related interest payments. Historically, we have funded our capital program, including acquisitions, with cash flows from operations, borrowings under credit facilities and use of project financing along with other debt and equity alternatives. Some of the significant financings, and corresponding uses, during 2006 were as follows:

In July 2006, we borrowed $835 million in a term loan (Term Loan) and entered into a new $300 million revolving credit facility. The proceeds of the Term Loan were used to fund the cash portion of the acquisition of Remington. We also issued 13,032,528 shares of our common stock to the

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Remington shareholders. See Note 10 Long-Term Debt in Item 8. *Financial Statements and Supplementary Data* for additional information.

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 our revolving credit facility. See Note 3 Initial Public Offering of Cal Dive, International, Inc. in Item 8. *Financial Statements and Supplementary Data* for additional information.

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. CDI expects to use the remaining availability under the revolving credit facility for working capital and other general corporate purposes (see Note 10 Long-term Debt in Item 8. *Financial Statements and Supplementary Data* for a detailed discussion of CDI s credit facilities). We do not have access to the unused portion of CDI s revolving credit facility.

In October 2006, we invested $15 million for a 50% interest in Kommandor, 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 in accordance with FIN 46. For additional information, see Item 8. *Financial Statements and Supplementary Data* Note 9 Consolidated Variable Interest Entities. We have named the vessel *Helix Producer I.*

Also in October 2006, we acquired a 58% interest in Seatrac 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 Seatrac shares (see Note 6 Other Acquisitions in Item 8. *Financial Statements and Supplementary Data* for a detailed discussion of Seatrac). We changed the name of the entity to Well Ops SEA Pty Ltd.

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.

Some of the significant financings and corresponding uses during 2005 and 2004 were as follows:

In March 2005, we issued $300 million of 3.25% Convertible Senior Notes due 2025 (Convertible Senior Notes). Proceeds from the offering were used for general corporate purposes including a capital contribution of $72 million (made in March 2005) to Deepwater Gateway to enable it to repay its term loan and to fund the acquisitions described below. For additional information on the terms of the Convertible Senior Notes, see Note 10 Long- term Debt in Item 8. *Financial Statements and Supplementary Data.*

In June 2005, we were the high bidder for seven vessels in a bankruptcy auction, including the *Express*, and a portable saturation system for approximately $85.9 million, including certain costs incurred related to the transaction.

In November 2005, we closed the transaction to purchase the diving assets of Acergy that operate in the Gulf of Mexico for approximately $46.1 million. In addition, we purchased the *DLB 801* and *Kestrel* for approximately $78.2 million were closed in the first quarter of 2006 when these assets completed their work campaigns in Trinidadian waters.

In June 2005, we acquired a mature property package on the Gulf of Mexico shelf from Murphy Oil Corporation (Murphy). The acquisition cost included both cash ($163.5 million) and the assumption of the abandonment liability from Murphy of approximately $32.0 million (a non-cash investing activity).

In June 2004, the preferred stockholder of our cumulative convertible preferred stock exercised its right and purchased an additional $30 million of cumulative convertible preferred stock. As a result, total convertible preferred stock outstanding increased to $55 million. Proceeds from this sale were used for general corporate purposes. For additional information on our preferred stock, see Note 12 Convertible Preferred Stock in Item 8. *Financial Statements and Supplementary Data.*

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In August 2004, we entered into a four-year, $150 million revolving credit facility. We cancelled this credit facility on June 30, 2006 and replaced it with the aforementioned $300 million revolving credit facility.

In accordance with the our Senior Credit Facilities, the Convertible Senior Notes, the MARAD debt and Cal Dive s credit facilities, we are required to comply with certain covenants and restrictions, including the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of December 31, 2006, we were in compliance with these covenants. The Senior Credit Facilities 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 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.

In 2007, we expect to make $77 million of interest payments, excluding the effect of interest rate swaps. In addition, we expect to make preferred dividend payments totaling approximately $3.8 million in 2007. As of December 31, 2006, we had $300 million of available borrowing capacity under our credit facilities, and CDI had $49 million of available borrowing under its revolving credit facility. See Note 10 Long-term Debt in Item 8. *Financial Statements and Supplementary Data* for additional information related to our long-term debts, including our obligations under capital commitments.

Working Capital

Cash flow from operating activities increased $271.6 million in 2006 as compared to 2005. This increase was primarily due to higher net income and positive working capital changes. Of the $194.8 million increase in net income in 2006, compared with 2005, approximately $96.5 million, net of $126.6 million of taxes, was related to the gain on the CDI initial public offering and related debt push down to CDI. Further, the net income increased due to higher oil and gas production and oil price realized in 2006, and as a result of net income contribution from the Remington, Acergy and Torch acquisitions. Working capital was more favorable in 2006 as compared to 2005 due to higher income tax payable, which we expect to pay in the first quarter of 2007 and as a result of more favorable accounts receivable turnover.

Cash flow from operating activities increased $15.6 million in 2005 as compared to 2004. This increase was primarily due to higher profitability of $69.9 million as a result of significantly higher oil and gas prices realized and improved utilization in 2005 as compared to 2004. These increases were partially offset by negative working capital changes.

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Investing Activities

Capital expenditures have consisted principally of strategic asset acquisitions related to 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, 2006, 2005 and 2004 were as follows (in thousands):

	Year Ended December 31,		
	2006	**2005**	**2004**
Capital expenditures:			
Contracting services	$ (130,938)	$ (90,037)	$ (21,016)
Shelf contracting	(38,086)	(32,383)	(1,792)
Oil and gas[1]	(282,318)	(238,698)	(27,315)
Production facilities	(17,749)	(369)	
Acquisition of businesses, net of cash acquired:			
Remington Oil and Gas Corporation[2]	(772,244)		
Acergy US. Inc. [3]	(78,174)	(66,586)	
Fraser Diving International Ltd. [3]	(21,954)		
Seatrac [3]	(10,571)		
Kommandor LLC	(5,000)		
(Purchases) sale of short-term investments	(285,395)	30,000	(30,000)
Investments in production facilities	(27,578)	(111,060)	(32,206)
Distributions from equity investments, net[4]		10,492	
Increase in restricted cash	(6,666)	(4,431)	(20,133)
Affiliate loan to OTSL		(1,500)	
Proceeds from sale of subsidiary stock	264,401		
Proceeds from sale of properties	32,342	5,617	(100)
Other, net		(970)	
Cash used in investing activities	$ (1,379,930)	$ (499,925)	$ (132,562)

(1) Includes approximately $38.3 million of capital expenditures related to exploratory dry holes in 2006. For additional information, see Item 8. *Financial Statements and Supplementary Data* Note 5.

(2) For additional information

related to the Remington acquisition, see Item 8. *Financial Statements and Supplementary Data* Note 4.

(3) For additional information related to the Acergy, Fraser and Seatrac acquisitions, see Item 8. *Financial Statements and Supplementary Data* Note 6.

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

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, 2005. These instruments are long-term variable rate bonds tied to short-term interest rates that are reset through a Dutch Auction process which occurs every 7 to 35 days and have been classified as available-for-sale securities. Although these instruments do not meet the definition of cash and cash equivalents, we expect to use these instruments to fund our working capital as needed due to the liquid nature of these securities.

Restricted Cash

As of December 31, 2006, we had $33.7 million of restricted cash, included in other assets, net, in the accompanying condensed consolidated balance sheet, all of which related to the escrow funds for decommissioning liabilities associated with the South Marsh Island 130 (SMI 130) acquisition in 2002 by our Oil and Gas segment. Under the purchase agreement for the acquisition, we were 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 escrow. We have fully escrowed the requirement as of December 31, 2006. We may use the restricted cash for decommissioning the related field.

Outlook

We anticipate capital expenditures in 2007 will range from $850 million to $1.1 billion. We may increase or decrease these plans based on various economic factors. We believe internally generated cash flow, the cash generated from the Cal Dive initial public offering and borrowings under our existing credit facilities will provide the necessary capital to fund our 2007 initiatives.

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual cash obligations as of December 31, 2006 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
Term Loan	832,900	8,400	16,800	16,800	790,900
MARAD debt	131,286	3,823	8,228	9,069	110,166
CDI Revolving Credit Facility	201,000			201,000	
Loan notes	11,146	11,146			
Capital leases	4,024	2,519	1,505		
Investments in Independence Hub, LLC[(3)]	4,268	4,268			
Drilling and development costs	138,900	130,100	8,800		
Property and equipment[(4)]	172,504	172,504			
Operating leases	62,958	32,205	20,652	5,421	4,680
Other[(6)]	9,624	6,859	2,765		
Total cash obligations	$ 1,868,610	$ 371,824	$ 58,750	$ 232,290	$ 1,205,746

(1) Excludes unsecured letters of credit outstanding at December 31, 2006 totaling $5.3 million. These letters of credit primarily guarantee various contract bidding, insurance activities and shipyard commitments.

(2) Maturity 2025. 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, 2006, no conversion triggers were met.

(3)

Excludes guaranty of performance related to the construction of the Independence Hub platform under Independence Hub, LLC (estimated to be immaterial at December 31, 2006). Under the guaranty agreement with Enterprise, we and Enterprise guarantee performance under the Independence Hub Agreement between Independence Hub and the producers group of exploration and production companies up to $426 million, plus applicable attorneys fees and related expenses. See Item 8. *Financial Statements and Supplementary Data* Note 8 for additional information.

(4) Costs incurred as of December 31, 2006 and additional property and equipment

commitments at December 31, 2006 consisted of the following (in thousands):

	Costs Incurred	Costs Committed	Total Project Cost
Caesar conversion	$ 15,014	$ 52,157	$ 110,000
Q4000 upgrade	15,300	18,966	40,000
Well Enhancer construction	19,443	87,343	160,000
Helix Producer I conversion	16,789	14,038	160,000
Total	$ 66,546	$ 172,504	$ 470,000

(5) Operating leases included facility leases and vessel charter leases. Vessel charter lease commitments at December 31, 2006 were approximately $40.2 million.

(6) Other consisted of scheduled payments pursuant to 3-D seismic license agreements.

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.

As of December 31, 2006, we have approximately $42.6 million accrued for the related royalties and interest. See Item 8. *Financial Statements and Supplementary Data* Note 17 for a detailed discussion of this contingency.

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

Revenues from Contracting Services and Shelf Contracting are derived from contracts that are typically of short duration. 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.

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.

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 or 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

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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.

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, 2006 and 2005 are expected to be billed and collected within one year.

We record revenues from the sales of crude oil and natural gas when delivery to the customer has occurred 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, 2006, the net imbalance was a $200,000 asset and was included in Other Current Assets ($4.7 million) and Accrued Liabilities ($4.5 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 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, although such estimates may change in the future as additional information becomes known.

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.

Certain data necessary to complete our final purchase price allocation is not yet available, and includes, but is not limited to, final tax returns that provide the underlying tax bases of Remington s assets and liabilities at July 1, 2006, valuation of certain proved and unproved oil and gas properties and identification and valuation of potential intangible assets. We expect to 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. Any future change in the value of net assets up until the one year period has expired will be offset by a corresponding increase or decrease in goodwill.

In 2006, we also completed the acquisition of Acergy, FDI and Seatrac. These acquisitions were accounted for as business combinations as well. We finalized the purchase price allocation for Acergy in the second quarter of 2006. The allocation of purchase price for FDI was based on preliminary valuations. Estimates and assumptions are subject to change upon the receipt and management s review of the final valuations. The primary areas of the purchase price allocation that are not yet finalized relate to post closing purchase price adjustments. The allocation of purchase price for Seatrac was based on preliminary valuations. Estimates and assumptions are subject to change upon the receipt and management s review of the final valuations. The primary areas of the purchase price allocation that are not yet finalized relate to the identification and valuation of potential intangible assets and valuation of certain equipment.

Goodwill and Other Intangible Assets

We test for the impairment of goodwill and other indefinite-lived intangible assets on at least an annual basis. We test for the impairment of other intangible assets when 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 are present. Our goodwill impairment test involves a comparison of the fair value of each of our reporting units with its carrying amount. The fair value is determined using discounted cash flows and other market-related valuation models, such as earnings multiples and comparable asset market values. We completed our annual goodwill impairment test as of November 1, 2006. Goodwill of $707.6 million was related to our Oil and Gas segment as of December 31, 2006. The goodwill was attributable to the Remington acquisition. Goodwill of $88.3 million and $73.9 million was related to our Contracting Services segment as of December 31, 2006 and 2005, respectively. Goodwill of $26.7 million and $27.8 million was related to our Shelf Contracting segment as of December 31, 2006 and 2005, respectively. None of our goodwill was impaired based on the impairment test performed as of November 1, 2006. See Item 8. *Financial Statements and Supplementary Data* Note 2 Summary of Significant Accounting Policies for goodwill and intangible assets related to the acquisitions. We will continue to test our goodwill and other indefinite-lived intangible assets annually on a consistent measurement date unless events occur or circumstances change between annual tests that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

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, 2006, our principal non-U.S. subsidiaries had accumulated earnings and profits of approximately $20.3 million. We have not provided deferred U.S. income tax on the accumulated earnings and profits. See Note 11 Income Taxes in Item 8. *Financial Statements and Supplementary Data* included herein for discussion of net operating loss carry forwards and deferred income taxes.

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. 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. Unamortized capital costs are reduced to fair value (based upon discounted cash flows) if the expected undiscounted future cash flows are less than the asset s net book value. Cash flows are determined based upon proved reserves using prices and costs consistent with those used for internal decision making. Although prices used are likely to approximate market, they do not necessarily represent current market prices.

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 2006, no impairments on unproved oil and gas properties occurred.

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.

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.

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, 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 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 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 such factors 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 \$167.7 million and \$121.4 million at December 31, 2006 and 2005, 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.

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

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contracts, primarily collars for a portion of our oil and gas production, interest rate swaps and foreign currency forward contracts. Our oil and gas costless collars, interest rate swaps and foreign currency forward exchange contracts qualify for hedge accounting and are reflected in our balance sheet at fair value. Hedge accounting does not apply to our oil and gas forward sales contracts.

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 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 (oil and gas costless collars, interest rate swaps and foreign currency forward exchange contracts) 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. 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 described in Note 2 Summary of Significant Accounting Policies in Item 8. *Financial Statements and Supplementary Data*.

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 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.

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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, 2006 and 2005, capitalized deferred drydock charges (described in Note 7 Detail of Certain Accounts in Item 8. *Financial Statements and Supplementary Data*) totaled $26.4 million and $18.3 million, respectively. During the years ended December 31, 2006, 2005 and 2004, drydock amortization expense was $12 million, $8.9 million and $4.9 million, respectively. We expect drydock amortization expense to increase in future periods since there was only limited amortization expense associated with the vessels we acquired in the Torch and Acergy acquisitions during the year ended December 31, 2006.

Equity Investments

We periodically review our investments in Deepwater Gateway, Independence Hub and OTSL 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. OTSL generated a net operating loss during 2006 which is an impairment indicator. As a result, we evaluated this investment to determine whether a permanent loss in value had occurred. We believe the current trend is temporary and have determined that the fair value of this investment, based on an estimate of its discounted cash flows, exceeds its carrying amount, and as a result there is no impairment at December 31, 2006.

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 and we analyze each claim for potential exposure and estimate the ultimate liability of each claim.

Recently Issued Accounting Principles

In June 2006, the FASB issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109* (FIN 48), which clarifies the accounting for uncertainty in income taxes recognized in accordance with FASB Statement No. 109, *Accounting for Income Taxes* (SFAS No. 109). FIN 48 clarifies the application of SFAS No. 109 by defining criteria that an individual tax position must meet for any part of the benefit of that position to be recognized in the financial statements. Additionally, FIN 48 provides guidance on the measurement, derecognition, classification and disclosure of tax positions, along with accounting for the related interest and penalties. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We adopted the provisions of FIN 48. The impact of the adoption of FIN 48 was immaterial on our financial position, results of operations and cash flows.

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In September 2006, the FASB issued Statement No. 157, *Fair Value Measurements* (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value in accordance with generally accepted accounting principles and expands disclosures about fair value measurements. The provisions of SFAS No. 157 are effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact, if any, of this statement.

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Item 8. ***Financial Statements and Supplementary Data.***

INDEX TO FINANCIAL STATEMENTS

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Management s Report on Internal Control Over Financial Reporting

Management of Helix Energy Solutions Group, Inc., together with its consolidated subsidiaries (the Company), is responsible for establishing and maintaining adequate internal control over financial reporting. The Company s internal control over financial reporting is a process designed under the supervision of the Company s principal executive and principal financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company s financial statements for external reporting purposes in accordance with U.S. generally accepted accounting principles.

As of the end of the Company s 2006 fiscal year, management conducted an assessment of the effectiveness of the Company s internal control over financial reporting using the criteria set forth in the framework established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management has determined that the Company s internal control over financial reporting as of December 31, 2006 was effective.

Our internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of the Company; provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of the Company; and 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 our financial statements.

Management s assessment of the effectiveness of the Company s internal control over financial reporting as of December 31, 2006 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report appearing on page 47, which expresses an unqualified opinion on management s assessment and on the effectiveness of Company s internal control over financial reporting as of December 31, 2006.

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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, 2006 and 2005, and the related consolidated statements of operations, shareholders equity and cash flows for each of the three years in the period ended December 31, 2006. 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, 2006 and 2005, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Helix Energy Solutions Group, Inc. s internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2007 expressed an unqualified opinion thereon.

As discussed in Note 13 to the consolidated financial statements, effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123 (Revised 2004), Share-Based Payment.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 28, 2007

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited management s assessment, included in the accompanying Management s Report on Internal Control Over Financial Reporting, that Helix Energy Solutions Group, Inc. maintained effective internal control over financial reporting as of December 31, 2006, 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. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of 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, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, 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, management s assessment that Helix Energy Solutions Group, Inc. maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Helix Energy Solutions Group, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, 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, 2006 and 2005, and the related consolidated statements of operations, shareholders equity and cash flows for each of the three years in the period ended December 31, 2006 and our report dated February 28, 2007 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 28, 2007

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

	December 31, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 206,264	$ 91,080
Short-term investments	285,395	
Accounts receivable		
Trade, net of allowance for uncollectible accounts of $982 and $585	287,875	197,046
Unbilled revenue	82,834	31,012
Other current assets	61,532	52,915
Total current assets	923,900	372,053
Property and equipment	2,721,362	1,259,014
Less Accumulated depreciation	(508,904)	(342,652)
	2,212,458	916,362
Other assets:		
Equity investments	213,362	179,844
Goodwill, net	822,556	101,731
Other assets, net	117,911	90,874
	$ 4,290,187	$ 1,660,864
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 240,067	$ 99,445
Accrued liabilities	199,650	138,464
Income taxes payable	147,772	7,288
Current maturities of long-term debt	25,887	6,468
Total current liabilities	613,376	251,665
Long-term debt	1,454,469	440,703
Deferred income taxes	436,544	167,295
Decommissioning liabilities	138,905	106,317
Other long-term liabilities	6,143	10,584
Total liabilities	2,649,437	976,564
Minority interests	59,802	
Convertible preferred stock	55,000	55,000

Commitments and contingencies		
Shareholders equity:		
Common stock, no par, 240,000 shares authorized, 90,628 and 77,694 shares issued	745,928	229,796
Retained earnings	752,784	408,748
Unearned compensation		(7,515)
Accumulated other comprehensive income (loss)	27,236	(1,729)
Total shareholders equity	1,525,948	629,300
	$ 4,290,187	$ 1,660,864

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

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

	Year Ended December 31, 2006	2005	2004
Net revenues:			
Contracting services	$ 937,317	$ 523,659	$ 300,082
Oil and gas	429,607	275,813	243,310
	1,366,924	799,472	543,392
Cost of sales:			
Contracting services	584,295	383,063	263,597
Oil and gas	267,221	133,337	107,883
	851,516	516,400	371,480
Gross profit	515,408	283,072	171,912
Gain on sale of assets	2,817	1,405	
Selling and administrative expenses	119,580	62,790	48,881
Income from operations	398,645	221,687	123,031
Equity in earnings of investments	18,130	13,459	7,927
Gain on subsidiary equity transaction	223,134		
Net interest expense and other	34,634	7,559	5,265
Income before income taxes	605,275	227,587	125,693
Provision for income taxes	257,156	75,019	43,034
Minority interest	725		
Net income	347,394	152,568	82,659
Preferred stock dividends	3,358	2,454	2,743
Net income applicable to common shareholders	$ 344,036	$ 150,114	$ 79,916
Earnings per common share:			
Basic	$ 4.07	$ 1.94	$ 1.05
Diluted	$ 3.87	$ 1.86	$ 1.03
Weighted average common shares outstanding:			

Basic	84,613	77,444	76,409
Diluted	89,874	82,205	79,062

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

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

	Common Stock Shares	Common Stock Amount	Retained Earnings	Unearned Compensation	Accumulated Other Comprehensive Income (Loss)	Total Shareholders Equity
Balance, December 31, 2003	75,716	$ 196,258	$ 178,718	$	$ 6,165	$ 381,141
Comprehensive income:						
Net income			82,659			82,659
Foreign currency translations Adjustments					10,780	10,780
Unrealized gain on hedges, net					846	846
Comprehensive income						94,285
Convertible preferred stock dividends			(1,620)			(1,620)
Accretion of preferred stock costs			(1,123)			(1,123)
Activity in company stock plans, net	1,120	10,481				10,481
Tax benefit from exercise of stock options		2,128				2,128
Balance, December 31, 2004	76,836	208,867	258,634		17,791	485,292
Comprehensive income:						
Net income			152,568			152,568
Foreign currency translations adjustments					(11,393)	(11,393)
Unrealized loss on hedges, net					(8,127)	(8,127)
Comprehensive income						133,048
Convertible preferred stock dividends			(2,454)			(2,454)
Activity in company stock plans, net	858	16,527		(7,515)		9,012
Tax benefit from exercise of stock options		4,402				4,402

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
Tax benefit from exercise of stock options		2,660				2,660
Balance, December 31, 2006	90,628	$ 745,928	$ 752,784	$	$ 27,236	$ 1,525,948

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

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

	Year Ended December 31,		
	2006	**2005**	**2004**
Cash flows from operating activities:			
Net income	$ 347,394	$ 152,568	$ 82,659
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	193,647	110,683	104,405
Asset impairment charge		790	3,900
Dry hole expense	38,335		
Equity in earnings of investments, net of distributions	(1,879)	(2,851)	(469)
Amortization of deferred financing costs	2,277	1,126	1,344
Stock compensation expense	9,364	1,406	
Deferred income taxes	57,235	42,728	42,046
Excess tax benefit from stock-based compensation	(2,660)	4,402	2,128
Gain on subsidiary equity transaction	(223,134)		
(Gain) loss on sale of assets	(2,817)	(1,405)	100
Minority interest	725		
Changes in operating assets and liabilities:			
Accounts receivable, net	(67,211)	(107,163)	(17,397)
Other current assets	9,969	(6,997)	(23,294)
Income tax payable	142,949	5,384	771
Accounts payable and accrued liabilities	39,551	59,241	42,521
Other noncurrent, net	(29,709)	(17,480)	(11,907)
Net cash provided by operating activities	514,036	242,432	226,807
Cash flows from investing activities:			
Capital expenditures	(469,091)	(361,487)	(50,123)
Acquisition of businesses, net of cash acquired	(887,943)	(66,586)	
(Purchases) sale of short-term investments	(285,395)	30,000	(30,000)
Investments in equity investments	(27,578)	(111,060)	(32,206)
Distributions from equity investments, net		10,492	
Increase in restricted cash	(6,666)	(4,431)	(20,133)
Proceeds from sale of subsidiary stock	264,401		
Proceeds from (payments on) sales of property	32,342	5,617	(100)
Other, net		(2,470)	
Net cash used in investing activities	(1,379,930)	(499,925)	(132,562)
Cash flows from financing activities:			
Borrowings under credit facilities	1,036,000		
Repayment of credit facilities	(2,100)		

Borrowings on Convertible Senior Notes		300,000	
Sale of convertible preferred stock, net of transaction costs			29,339
Borrowings under MARAD loan facility		2,836	
Repayment of MARAD borrowings	(3,641)	(4,321)	(2,946)
Borrowing under loan notes	5,000		
Repayment on line of credit			(30,189)
Deferred financing costs	(11,839)	(11,678)	(4,550)
Repayments of term loan borrowings			(35,000)
Capital lease payments	(2,827)	(2,859)	(3,647)
Preferred stock dividends paid	(3,613)	(2,200)	(1,620)
Redemption of stock in subsidiary		(2,438)	(2,462)
Repurchase of common stock	(50,266)		
Excess tax benefit from stock-based compensation	2,660		
Exercise of stock options, net	8,886	8,726	11,038
Net cash provided by (used in) financing activities	978,260	288,066	(40,037)
Effect of exchange rate changes on cash and cash equivalents	2,818	(635)	556
Net increase in cash and cash equivalents	115,184	29,938	54,764
Cash and cash equivalents:			
Balance, beginning of year	91,080	61,142	6,378
Balance, end of year	$ 206,264	$ 91,080	$ 61,142

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, Cal Dive International, Inc. changed its name to Helix Energy Solutions Group, Inc. (Helix or the Company). Unless the context indicates otherwise, the terms we, us and our in this report refer collectively to Helix and its subsidiaries. We are an international offshore energy company that provides development solutions and other key services (contracting services operations) to the open market as well as to our own reservoirs (oil and gas operations). Our oil and gas business is a prospect generating, exploration, development and production company.

Contracting Services Operations

We seek to provide services and methodologies which we believe are critical to finding and developing offshore reservoirs and maximizing the economics from marginal fields. Those life of field services are organized in five disciplines: reservoir and well tech services, drilling, production facilities, construction and well operations. We have disaggregated our contracting services operations into three reportable segments in accordance with SFAS 131: Contracting Services (which currently includes deepwater construction, well ops and reservoir and well tech services); Shelf Contracting and Production Facilities. Within our contracting services operations, we operate primarily in the Gulf of Mexico, the North Sea and Asia/Pacific regions, with services that cover the lifecycle of an offshore oil or gas field. The assets of our Shelf Contracting segment, including the 40% interest in Offshore Technology Solutions Limited (OTSL), are the assets of Cal Dive International, Inc. (Cal Dive or CDI). In December 2006, Cal Dive completed an initial public offering of 22,173,000 shares of its stock. As a result of Cal Dive s initial public offering, together with shares issued to CDI employees immediately after the offering, our ownership in CDI was 73.0% as of December 31, 2006.

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 and to achieve better returns than are likely through pure service contracting. Over the last 15 years we have evolved this business model to include not only mature oil and gas properties but also proved reserves yet to be developed, and most recently with the acquisition of Remington, an exploration, development and production company. 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.

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 investments in Deepwater Gateway, Independence Hub and OTSL under the equity method of accounting. Minority interests represent minority shareholders proportionate share of the equity in CDI, Seatrac and Kommandor. 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. Reclassifications of prior year information to current year presentation related primarily to the following:

- reporting dry hole cost as a component of our exploration costs instead of as a component of depreciation, depletion and amortization costs on the statement of cash flows due to the significance of our oil and gas exploration activities as a result of our recent acquisition of Remington (see Note 5 Oil and Gas Properties);

- reporting the purchase and sale of municipal auction rate securities from net cash provided by operating activities to net cash provided by (used in) investing activities for 2006, 2005 and 2004; and

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reporting treasury stock outstanding as a component of common stock as of December 31, 2006, 2005 and 2004 as treasury stock is not legally recognized in Minnesota, our state of incorporation.

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, 2006 and 2005, we had $33.7 million and $27.0 million, respectively, of restricted cash (see Note 7 Detail of Certain Accounts) all of which was related to the escrow funds for decommissioning liabilities associated with the SMI 130 acquisition in 2002 by our Oil and Gas segment. Under the purchase agreement for those acquisitions, we were obligated to escrow 50% of production up to the first $20 million of escrow and 37.5% of production on the remaining balance up to $33 million in total escrow. We had fully escrowed the requirement as of December 31, 2006. We may use the restricted cash for decommissioning the related field.

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

	Years Ended December 31,		
	2006	**2005**	**2004**
Interest paid (net of capitalized interest)	$26,105	$ 9,990	$3,224
Income taxes paid	$56,972	$22,495	$ 252

Non-cash investing activities for the years ended December 31, 2006, 2005 and 2004 included $39.0 million, $28.5 million and $8.9 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 comprehensive income until realized. All of our short-term investments at December 31, 2006 were municipal auction rate securities. We did not hold these types of securities at December 31, 2005. These instruments are long-term variable rate bonds tied to short-term interest rates that are reset through a Dutch Auction process which occurs every 7 to 35 days and have been classified as available-for-sale securities. The stated maturities of these securities range from November 2015 to November 2045. Although these instruments do not meet the definition of cash and cash equivalents, we expect to use these instruments to fund our working capital as needed due to the liquid nature of these securities. As a result, they are classified as short-term investments.

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. 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.

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	2006	2005
Vessels	10 to 30 years	$ 883,635	$ 609,558
Offshore oil and gas leases and related equipment	Units-of-Production	1,746,896	601,866
Machinery, equipment buildings and leasehold improvements	5 to 30 years	90,831	47,590
Total property and equipment		$ 2,721,362	$ 1,259,014

The cost of repairs and maintenance is charged to operations as incurred, while the cost of improvements is capitalized. Total repair and maintenance charges were $51.0 million, $24.0 million and $17.0 million for the years ended December 31, 2006, 2005 and 2004, 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 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. Impairment expenses are included as a component of cost of sales. 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. During 2005 and 2004, we recorded impairment charges of $790,000 and $3.9 million, respectively, on certain vessels that met the impairment criteria. Such charges are included in cost of sales in the accompanying Consolidated Statements of Operations. These assets were subsequently sold in 2005 and 2006, for an aggregate gain on the disposals of approximately $322,000. There were no such impairments during 2006.

Assets are classified as held for sale when we have a plan for disposal of certain assets and those assets meet the held for sale criteria. At December 31, 2006 and 2005, we had classified certain assets intended to be disposed of within a 12-month period as assets held for sale totaling approximately $700,000 and $7.9 million, respectively. Assets classified as held for sale are included in other current assets (see Note 7 Detail of Certain Accounts). Remaining assets held for sale were disposed of in January 2007.

In March 2005, we completed the sale of certain Contracting Services property and equipment for $4.5 million that was previously included in assets held for sale. Proceeds from the sale consisted of $100,000 cash and a $4.4 million promissory note bearing interest at 6% per annum due in semi-annual installments beginning September 30, 2005 through March 31, 2010. In addition to the asset sale, we entered into a five-year services agreement with the purchaser whereby we have committed to provide the purchaser with a specified amount of services for its Gulf of Mexico fleet on an annual basis ($8 million per year). The measurement period related to the services agreement began with the twelve months ending June 30, 2006 and continues every six months until the contract ends on March 31, 2010. Further, the promissory note stipulates that should we not meet our annual services commitment, the purchaser can defer its semi-annual principal and interest payment for six months. We determined that the estimated gain on the sale of approximately $2.5 million should be deferred and recognized as the principal and interest payments are received from the purchaser over the term of the promissory note. As of December 31, 2006 and 2005, the balance of the outstanding receivable was $3.6 million and $4.0 million, respectively, and for the years ended

December 31, 2006 and 2005, we recognized $216,000 and

$210,000, respectively, of partial gain on this sale.

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 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. The majority of our interests in oil and gas properties are located offshore in United States waters. We follow the successful efforts method of accounting for our interests in oil and gas properties. 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. Costs incurred relating to unsuccessful exploratory wells are expensed in the period when the drilling is determined to be unsuccessful. See Exploratory Costs below. Properties are periodically assessed for impairment in value, with any impairment charged to expense.

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 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 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. See Note 5 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 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. 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.

Equity Investments

We periodically review our investments in Deepwater Gateway, Independence Hub and OTSL 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. OTSL has generated a net operating loss during 2006 which is an impairment indicator. As a result, we evaluated this investment to determine whether a permanent loss in value had occurred. Based on this evaluation, OTSL currently has the ability to sustain an earnings capacity which would justify the carrying amount of the investment, and as a result there is no impairment at December 31, 2006.

Goodwill and Other Intangible Assets

We test for the impairment of goodwill on at least an annual basis. Intangible assets with finite useful lives are amortized using the straight-line method over their useful lives. Intangible assets that have indefinite useful lives are not amortized, but are tested for impairment annually and when 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 are present. Our goodwill impairment test involves a comparison of the fair value of each of our reporting units with its carrying amount. The fair value is determined using discounted cash flows and other market-related valuation models, such as earnings multiples and comparable asset market values. We completed our annual goodwill impairment test as of November 1, 2006. The changes in the carrying amount of goodwill by the applicable segments are as follows (in thousands):

	Contracting Services	**Shelf Contracting**	**Oil and Gas**	**Total**
Balance at December 31, 2004	$ 69,220	$ 14,973	$	$ 84,193
Acergy acquisition		12,841		12,841
Helix RDS acquisition	6,915			6,915
Tax and other adjustments	(2,218)			(2,218)
Balance at December 31, 2005	73,917	27,814		101,731
Remington acquisition			707,596	707,596
Seatrac acquisition	7,415			7,415
Acergy acquisition adjustment		(1,148)		(1,148)
Helix RDS acquisition adjustment	2,634			2,634
Tax and other adjustments	4,328			4,328
Balance at December 31, 2006	$ 88,294	$ 26,666	$ 707,596	$ 822,556

Of our total goodwill at December 31, 2006 and 2005, approximately $41.0 million and $39.1 million, respectively, was expected to be deducted for tax purposes. None of our goodwill was impaired based on the impairment test performed as of November 1, 2006. We will continue to test our goodwill and other indefinite-lived intangible assets annually on a consistent measurement date unless events occur or circumstances change between annual tests that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

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, 2006 and 2005, capitalized deferred drydock charges (included in Other Assets, Net, see Note 7 Detail of Certain Accounts) totaled $26.4 million and $18.3 million, respectively. During the years ended December 31, 2006, 2005 and 2004, drydock amortization expense was $12.0 million, $8.9 million and $4.9 million, respectively.

Accounting for Decommissioning Liabilities

We account for our decommissioning liabilities in accordance with Statement of Financial Accounting Standards (SFAS) No. 143, *Accounting for Asset Retirement Obligations*. 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 adjustments in the cost estimate are reflected in the liability and the amounts continue to be amortized 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 2006 and 2005 (in thousands):

	2006	**2005**
Asset retirement obligation at January 1,	$ 121,352	$ 82,030
Liability incurred during the period	40,442	36,119
Liability settled during the period	(6,669)	(1,913)
Revision in estimated cash flows	3,929	(583)
Accretion expense (included in depreciation and amortization)	8,617	5,699
Asset retirement obligations at December 31,	$ 167,671	$ 121,352

Revenue Recognition

Revenues from Contracting Services and Shelf Contracting are derived from contracts that are typically of short duration. 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.

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.

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.

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, 2006 and 2005 are expected to be billed and collected within one year.

We record revenues from the sales of crude oil and natural gas when delivery to the customer has occurred 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, 2006, the net imbalance was a $200,000 asset and was included in Other Current Assets ($4.7 million) and Accrued Liabilities ($4.5 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.

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 Seatrac 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, 2006 and 2005 and the resulting translation adjustment, which was an unrealized gain (loss) of $17.6 million and $(11.4) million, respectively, is included in accumulated other comprehensive income (loss), a component of shareholders equity. Beginning in 2004, deferred taxes were not provided on foreign currency translation adjustments for operations where we consider our undistributed earnings of our principal non-U.S. subsidiaries to be permanently reinvested. As a result, cumulative deferred taxes on translation adjustments totaling approximately $6.5 million were reclassified from noncurrent deferred income taxes and accumulated other comprehensive income. All foreign currency transaction gains and losses are recognized currently in the statements of operations. These amounts for the years ended December 31, 2006 and 2005 were not material to our results of operations or cash flows.

Canyon Offshore, our ROV subsidiary, has operations in the United Kingdom and Asia Pacific. Further, FDI has operations in Southeast Asia. Canyon and FDI 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 the year ended December 31, 2006, 2005 and 2004, respectively, were not material to our results of operations or cash flows.

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 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 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 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 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 the hedging transactions are highly effective in offsetting changes in cash flows of its 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.

Commodity Hedges

The fair value of hedging 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.

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

During 2006 and 2005, we entered into various cash flow hedging costless collar contracts to stabilize cash flows relating to a portion of our expected oil and gas production. All of these qualified for hedge accounting. The aggregate fair value of the hedge instruments was a net asset (liability) of $5.2 million and $(13.4) million as of December 31, 2006 and 2005, respectively. For the years ended December 31, 2006, 2005 and 2004, we recorded unrealized gains (losses) of approximately $12.1 million, $(8.1) million and $846,000, net of taxes of $6.5 million, $4.4 million and $456,000, respectively, in accumulated other comprehensive income (loss), a component of shareholders equity, as these hedges were highly effective. The balance in the cash flow hedge adjustments account is recognized in earnings when the related hedged item is sold. During 2006, 2005 and 2004, we reclassified approximately $9.0 million, $(14.1) million and $(11.1) million, respectively, of gains (losses) from other comprehensive income to Oil and Gas revenues upon the sale of the related oil and gas production.

Hedge ineffectiveness related to cash flow hedges was a loss of $1.8 million, net of taxes of $951,000 in 2005 as reported in that period s earnings as a reduction of oil and gas productive revenues. Hedge ineffectiveness resulted from our inability to deliver contractual oil and gas production in 2005 due primarily to the effects of Hurricanes *Katrina* and *Rita.* No hedge ineffectiveness related to our commodity hedges were recognized in 2006 and 2004.

As of December 31, 2006, we had the following volumes under derivative contracts related to our oil and gas producing activities totaling 1,170 MBbl of oil and 9,500 MMbtu of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			
January 2007 December 2007	Collar	98 MBbl	$49.74 $66.96
Natural Gas:			
January 2007 June 2007	Collar	650,000 MMBtu	$ 7.85 $12.90
July 2007 December 2007	Collar	933,333 MMBtu	$ 7.50 $10.13

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.

As of December 31, 2006, we had oil forward sales contracts for the period from January 2007 through June 2007. The contracts cover an average of 40 MBbl per month at a weighted average price of $70.83. In addition, we had natural gas forward sales contracts for the period from January 2007 through June 2007. The contracts cover an average of 750,833 MMbtu per month at a weighted average price of $9.49. Hedge accounting does not apply to these contracts.

Subsequent to December 31, 2006, we entered into two additional natural gas costless collars. The first collar covers 300,000 MMBtu per month at a price of $7.50 to $9.92 for the period from October through December 2007. The second collar is for the period of January through March 2008. The collar covers 600,000 MMBtu per month at a price of $7.50 to $12.55. We also entered into an oil costless collar for 60 MBbl per month for the period from January 2008 to June 2008 at a weighted average price of $55.00 to $73.58.

Interest Rate Hedge

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. These interest rate swaps qualify for hedge accounting. See " Note 10 Long-Term Debt below for a detailed discussion of our Term Loan. The aggregate fair value of the hedge instruments was a net liability of $531,000 as of December 31, 2006. For the year ended December 31, 2006, these hedges were highly effective.

Foreign Currency Hedge

In December 2006, we entered into various foreign exchange forwards to stabilize expected cash outflows relating to a shipyard contract where the contractual payments are denominated in euros. These forward contracts qualify for hedge accounting. Under the forward contracts, we have hedged payments totaling 18.0 million to be settled in June and December 2007 at exchange rates of 1.3255 and 1.3326, respectively. The aggregate fair value of the hedge instruments was a net liability of $184,000 as of December 31, 2006. For the year ended December 31, 2006, these hedges were highly effective.

Earnings per Share

Basic earnings per share (EPS) is computed by dividing the net income available to common shareholders by the weighted-average shares of outstanding common stock. The calculation of diluted EPS is similar to basic EPS, except 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, 2006, 2005 and 2004 were as follows (in thousands):

	Year Ended December 31,					
	2006		2005		2004	
	Income	**Shares**	**Income**	**Shares**	**Income**	**Shares**
Earnings applicable per common share Basic	$ 344,036	84,613	$ 150,114	77,444	$ 79,916	76,409
Effect of dilutive securities:						
Stock options		449		772		609
Restricted shares		160		240		
Employee stock purchase plan		12				
Convertible Senior Notes		1,009		118		
Convertible preferred stock	3,358	3,631	2,454	3,631	2,743	2,044
Earnings applicable per common share Diluted	$ 347,394	89,874	$ 152,568	82,205	$ 82,659	79,062

There were no antidilutive stock options in the years ended December 31, 2006, 2005 and 2004, respectively. In addition, approximately 1,020,000 shares attributable to the convertible preferred stock were excluded in the year ended December 31, 2004, calculation of diluted EPS, as the effect was antidilutive. Net income for the diluted earnings per share calculation for the years ended December 31, 2006, 2005 and 2004 were adjusted to add back the preferred stock dividends and accretion on the 3.6 million shares, 3.6 million shares and 2.0 million shares, respectively.

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.

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The following table reflects our pro forma results if the fair value method had been used for the accounting for these plans for the years ended December 31, 2005 and 2004 (in thousands, except per share amounts):

	Year Ended December 31, 2005	Year Ended December 31, 2004
Net income applicable to common shareholders:		
As Reported	$ 150,114	$ 79,916
Add back: Stock-based compensation cost included in reported net income, net of taxes	914	
Deduct: Total stock-based compensation cost determined under the fair value method, net of tax	(2,566)	(2,368)
Pro Forma	$ 148,462	$ 77,548
Earnings per common share:		
Basic:		
As reported	$ 1.94	$ 1.05
Pro forma	$ 1.92	$ 1.02
Diluted:		
As reported	$ 1.86	$ 1.03
Pro forma	$ 1.84	$ 1.00

For the purposes of pro forma disclosures, the fair value of each option grant was estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used in 2004: expected dividend yields of 0%; expected lives of ten years, risk-free interest rate assumed to be 4.0%, and expected volatility to be 56%. There were no stock option grants in 2006 and 2005. The fair value of shares issued under the Employee Stock Purchase Plan was based on the 15% discount received by the employees. The weighted average per share fair value of the options granted in 2004 was $8.80. No stock options were granted in 2005. The estimated fair value of the options is amortized to pro forma expense over the vesting period. See Note 13 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 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 for discussion of CDI s initial public offering.

Consolidation of Variable Interest Entities

Effective December 31, 2003, we adopted and applied the provisions of FIN 46 for all 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 9 related to our consolidated variable interest entities.

Fair Value of Financial Instruments

Our financial instruments consist of cash and cash equivalents, short-term investments, accounts receivable, accounts payable and our long-term debts. The carrying amount of cash and cash equivalents, short-term investments, accounts receivable and accounts payable approximate fair value due to the highly liquid nature of these short-term instruments. The carrying amount and estimated fair value of our debt instruments, including current maturities as of December 31, 2006 and 2005 were as follows (amount in thousands):

	2006		2005	
	Carrying Value	**Fair Value**	**Carrying Value**	**Fair Value**
Term Loan[1]	$832,900	$834,462	$	$
Cal Dive Revolving Credit Facility[2]	201,000	201,000		
Convertible Senior Notes[1]	300,000	378,780	300,000	433,695
MARAD Debt[3]	131,286	126,691	134,926	132,565
Loan Notes[4]	11,146	11,146	5,393	5,393

(1) The fair values of these instruments were based on quoted market prices as of December 31, 2006 and 2005, if applicable.

(2) The carrying value of the Cal Dive revolving credit facility approximates fair value as of December 31, 2006.

(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.

(4) The carrying value of the loan notes approximates fair value as the maturity dates of these securities are 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 make capital expenditures on exploration, drilling and production operations offshore, the level of which is generally dependent on the prevailing view of the future oil and gas prices, which have been characterized by significant volatility. Our customers consist primarily of major, 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 was as follows: 2006 Louis Dreyfus Energy Services (10%) and Shell Offshore, Inc. (10%); 2005 Louis Dreyfus Energy Services (10%) and Shell Trading (US) Company (10%); and 2004 Louis Dreyfus Energy Services (11%) and Shell Trading (US) Company (10%). All of these customers were purchasers of our oil and gas production.

Recently Issued Accounting Principles

In June 2006, the FASB issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109* (FIN 48), which clarifies the accounting for uncertainty in income taxes recognized in accordance with FASB Statement No. 109, *Accounting for Income Taxes* (SFAS No. 109). FIN 48 clarifies the application of SFAS No. 109 by defining criteria that an individual tax position must meet for any part of the benefit of that position to be recognized in the financial statements. Additionally, FIN 48 provides guidance on the measurement, derecognition, classification and disclosure of tax positions, along with accounting for the related interest and penalties. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. On January 1, 2007, we adopted the provisions of FIN 48 and the impact of the adoption was immaterial on our financial position, results of operations and cash flows.

In September 2006, the FASB issued Statement No. 157, *Fair Value Measurements* (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value in accordance with generally accepted accounting principles and expands disclosures about fair value measurements. The provisions of SFAS No. 157 are effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact, if any, of this statement.

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 International, Inc., our then wholly owned subsidiary. Cal Dive subsequently sold 22,173,000 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. In December 2006, Cal Dive borrowed $201 million under the facility and distributed $200 million of the proceeds to us as a dividend. For additional information related to the Cal Dive credit facilities, see Note 10 Long-term Debt below. We recognized an after-tax gain of $96.5 million, net of taxes of $126.6 million as a result of these transactions. We plan to use 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%. Subject to market conditions, we may sell additional shares of Cal Dive common stock in the future.

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, 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, 2006, we have a long-term receivable from CDI of approximately $11.3 million related to the Tax Matters Agreement. For additional information related to the Tax Matters Agreement, see Note 11 Income Taxes .

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 stock and the assumption of $349.6 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 13,032,528 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 agreement (see Note 10 Long-Term Debt below).

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 excess being recorded in goodwill. The following table summarizes the estimated preliminary fair values of the assets acquired and liabilities assumed at the date of acquisition (in thousands):

Current assets	$ 154,336
Property and equipment	859,722
Goodwill	707,596
Other intangible assets(1)	6,800
Total assets acquired	$ 1,728,454
Current liabilities	$ 125,662
Deferred income taxes	201,317
Decommissioning liabilities (including current portion)	20,832
Other non-current liabilities	1,800
Total liabilities assumed	$ 349,611
Net assets acquired	$ 1,378,843

(1) The intangible asset is related to a favorable drilling rig contract and several non-compete agreements between the Company and certain members of senior management. The preliminary

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fair value of the drilling rig contract was $5.0 million and that amount will be reclassified into property and equipment if drilling of certain exploratory wells is successful. If drilling is unsuccessful, the intangible asset will be expensed in the period drilling is determined to be unsuccessful. The preliminary fair value of the non-compete agreements was $1.8 million, which will be amortized over the term of the agreements (three years) on a straight-line basis.

Certain data necessary to complete our final purchase price allocation is not yet available, and includes, but is not limited to, final tax returns that provide the underlying tax basis of Remington s assets and liabilities at July 1, 2006, valuation of certain proved and unproved oil and gas properties and identification and valuation of potential intangible assets. We expect to 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. Any future change in the value of net assets up until the one year period has expired will be offset by a corresponding increase or decrease in goodwill.

The results of the Remington acquisition are included in the accompanying statements of operations since the date of purchase in our Oil and Gas segment . See pro forma combined operating results of the Company and the Remington acquisition for the years ended December 31, 2006 and 2005 in Note 6 Other Acquisitions below.

Note 5 Oil and Gas Properties

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

At December 31, 2006, we had capitalized approximately $50 million of exploratory drilling costs associated with ongoing exploration and/or appraisal activities. Such 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, 2006 and 2005 (in thousands):

	2006	2005
Huey	$ 11,378	$
Noonan	27,824	
Castleton (part of *Gunnison*)	7,070	5,844
Tulane		6,170
Other	3,711	
Total	$ 49,983	$ 12,014

The following table reflects net changes in suspended exploratory well costs during the year ended December 31, 2006, 2005 and 2004 (in thousands):

	2006	2005	2004
Beginning balance at January 1,	$ 12,014	$ 1,052	$
Additions pending the determination of proved reserves	138,679	10,962	1,052
Reclassifications to proved properties	(62,375)		
Charged to dry hole expense	(38,335)		
Ending balance at December 31,	$ 49,983	$ 12,014	$ 1,052

As of December 31, 2006, all of these exploratory well costs had been capitalized for a period of one year or less, except for *Castleton*. We are not the operator of *Castleton*.

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Further, the following table details the components of exploration expense for the years ended December 31, 2006, 2005 and 2004 (in thousands):

	Years Ended December 31,		
	2006	2005	2004
Delay rental and geological and geophysical costs	$ 4,780	$ 6,465	$
Dry hole expense	38,335		
Total exploration expense	$ 43,115	$ 6,465	$

In addition, 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 damages caused by these hurricanes. No insurance recoveries were received in 2005.

We agreed to participate in the drilling of an exploratory well (Tulane prospect) that was drilled in the first quarter of 2006. This prospect targeted reserves in deeper sands, within the same trapping fault system, of a currently producing well. In March 2006, mechanical difficulties were experienced in the drilling of this well, and after further review, the well was plugged and abandoned. The total estimated cost to us of approximately $21.7 million was charged to earnings during the year ended December 31, 2006. We continue to evaluate various options with the operator for recovering the potential resources. Further, in the third quarter of 2006, we expensed approximately $15.9 million of exploratory drilling costs related to two deep shelf properties (acquired in the Remington acquisition which were in process prior to July 1, 2006) in which we determined commercial quantities of hydrocarbons were not discovered.

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 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 mid-2008 in the *Phoenix* field.

In December 2006, we acquired a 100% working interest in the *Camelot* oil field in the U. K. North Sea for assumption of certain decommissioning liabilities totaling approximately $7.6 million. We have commenced existing field rejuvenation and expect first production in 2007.

In March 2005, we acquired a 30% working interest in a proved undeveloped field in Atwater Block 63 (Telemark) of the Deepwater Gulf of Mexico for cash and assumption of certain decommissioning liabilities. In December 2005, we were advised by Norsk Hydro USA Oil and Gas, Inc. (Norsk Hydro) that Norsk Hydro would not pursue its development plan for the deepwater discovery. As a result, we acquired a 100% working interest and operatorship in April 2006 following a non-consent to our plan of development by Norsk Hydro. Our interest in this property and surrounding fields was sold in July 2006 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 the third quarter of 2006 related to this sale.

In June 2005, we acquired a mature property package on the Gulf of Mexico shelf from Murphy Oil Corporation (Murphy). The acquisition cost included both cash ($163.5 million) and the assumption of the estimated abandonment liability from Murphy of approximately $32.0 million (a non-cash investing activity). The acquisition represented essentially all of Murphy s Gulf of Mexico Shelf properties consisting of eight operated and eleven non-operated fields. We estimated proved reserves of the acquisition to be approximately 75 Bcfe. The results of the acquisition are included in the accompanying statements of operations since the date of purchase. See pro forma combined operating results of the Company and the Murphy acquisition for the years ended December 31, 2006 and 2005 in Note 6 Other Acquisitions below.

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 $41.0 million, $34.0 million and $26.7 million for the years ended December 31, 2006, 2005 and 2004, 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.

Note 6 Other Acquisitions

2006

Fraser Diving International Ltd.

In July 2006, we acquired the business of Singapore-based Fraser Diving International Ltd for an aggregate purchase price of approximately $29.3 million, subject to post-closing adjustments, and the assumption of $2.2 million of liabilities. FDI owns 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 FDI 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 following table summarizes the estimated preliminary 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 allocation of the purchase price was based upon preliminary valuations. Estimates and assumptions are subject to change upon the receipt and management s review of the final valuations. The primary areas of the purchase price allocation that are not yet finalized relate to post closing purchase price adjustments. The final valuation of net assets is expected to be completed no later than one year from the acquisition date. The results of FDI are 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 years ended December 31, 2006 and 2005 (adjusted to reflect the results of operations of FDI prior to its acquisition) are not provided because the pre-acquisition results related to FDI were not material to the historical results of the Company.

Seatrac Pty, Ltd.

In October 2006, we acquired a 58% interest in Seatrac 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 Seatrac shares. We have changed the name of this entity to Well Ops SEA Pty Ltd. The proceeds from the newly issued shares were used by the entity to pay down existing indebtedness of approximately $1.9 million and to provide funding for capital expenditures of $1.5 million. Seatrac is a subsea well intervention and engineering services company located in Perth, Australia. Under the terms of the purchase agreement, we will be obligated to purchase the remaining 42% of the shares outstanding from the existing shareholders for $9.1 million upon Seatrac s successfully obtaining a significant commercial contract. In the event that the conditions required for the additional purchase are not met, we will be under no obligation to purchase the remaining 42% of Seatrac. The option period to acquire the remaining 42% expires on June 30, 2007. In addition, the agreement with the existing shareholders provides for an earnout period of five years from the closing date for the purchase of the remaining 42% of Seatrac. If during this five-year period Seatrac achieves certain financial performance objectives, the shareholders will be entitled to additional consideration of approximately $4.6 million.

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 our portion of the estimated preliminary fair values of the assets acquired and liabilities assumed at the date of acquisition (in thousands):

Cash and cash equivalents	$ 1,215
Other current assets	1,906
Property and equipment	4,218
Goodwill	7,136
Total assets acquired	$ 14,475
Accounts payable and accrued liabilities	$ 1,810
Net assets acquired	$ 12,665

The allocation of the purchase price was based upon preliminary valuations. Estimates and assumptions are subject to change upon the receipt and management s review of the final valuations. The primary areas of the purchase price allocation that are not yet finalized relate to the identification and valuation of potential intangible assets and valuation of certain equipment. The final valuation of net assets is expected to be completed no later than one year from the acquisition date. The results of Seatrac are included in the accompanying consolidated statements of operations in our Contracting Services segment since the date of purchase. Pro forma combined operating results for the year ended December 31, 2006 and 2005 (adjusted to reflect the results of operations of Seatrac prior to its acquisition) are not provided because the pre-acquisition results related to Seatrac were not material to the historical results of the Company.

Caesar

In January 2006, our wholly owned subsidiary, Vulcan Marine Technology LLC (Vulcan), acquired the *Caesar* (formerly known as the *Baron*), a four year old mono-hull vessel originally built for the cable lay market, for approximately $27.5 million in cash. The vessel was under charter to a third-party until mid January 2007. After the completion of the charter, the vessel was in transit to a shipyard in China where we plan to convert the vessel into a deepwater pipelay asset. The vessel is 485 feet long and already has a state-of-the-art, class 2, dynamic positioning system. The conversion program will primarily involve the installation of a conventional S lay pipelay system together with a main crane and a significant upgrade to the accommodation capability. A conversion team has already been assembled with a base at Rotterdam, the Netherlands, and the vessel is likely to enter service during the second half of 2007. The estimated cost to acquire and convert the vessel will be approximately $137.5 million. We have entered into an agreement with the third party that leased the vessel, whereby the third party has an option to purchase up to 49% of Vulcan for consideration totaling the proportionate share of the cost of the vessel plus the actual cost of conversion (conversion cost is estimated to be $110 million). The third party must make all contributions to Vulcan on or before March 31, 2007.

2005

Torch Offshore, Inc.

In a bankruptcy auction held in June 2005, we were the high bidder for seven vessels, including the *Express,* and a portable saturation system for approximately $85.9 million, subject to the terms of an amended and restated asset purchase agreement, executed in May 2005, with Torch. This transaction received regulatory approval, including completion of a review pursuant to a Second Request from the U.S. Department of Justice, in August 2005 and subsequently closed. The total purchase price for the Torch vessels was approximately $85.9 million, including certain costs incurred related to the transaction. The acquisition was an asset purchase with the acquisition price allocated to the assets acquired based upon their estimated fair values. All of the assets acquired, except for the *Express* (Contracting Services segment) are included in the Shelf Contracting segment. The results of the acquired vessels are included in the accompanying consolidated statements of operations since the date of the purchase, August 31, 2005.

Acergy US Inc.

In April 2005, we agreed to acquire the diving and shallow water pipelay assets of Acergy that operate in the waters of the Gulf of Mexico and Trinidad. The transaction included: seven diving support vessels; two diving and pipelay vessels (the *Kestrel* and the *DLB 801);* a portable saturation diving system; various general diving equipment and Louisiana operating bases at the Port of Iberia and Fourchon. All of the assets are included in the Shelf Contracting segment. The transaction required regulatory approval, including the completion of a review pursuant to a Second Request from the U.S. Department of Justice. On October 18, 2005, we received clearance from the U.S. Department of Justice to close the purchase from Acergy. Under the terms of the clearance, we were required to divest two diving support vessels and a portable saturation diving system from the combined asset package acquired through this transaction and the Torch transaction which closed in August 2005. We have since disposed of one diving support vessel and a portable saturation diving system prior to December 31, 2006, and disposed of the remaining diving support vessel in January 2007. These assets were included in assets held for sale totaling approximately $700,000 and $7.8 million as of December 31, 2006 and 2005, respectively. On November 1, 2005, we closed the transaction to purchase the Acergy diving assets operating in the Gulf of Mexico. We acquired the *DLB 801* in January 2006 for approximately $38.0 million and the *Kestrel* for approximately $39.9 million in March 2006.

The Acergy acquisition was accounted for as a business combination with the acquisition price allocated to the assets acquired and liabilities assumed based upon their fair values, with the excess being recorded as goodwill. The final valuation of net assets was completed in the second quarter of 2006. The total transaction value for all of the assets was approximately $124.3 million. The allocation of the Acergy purchase prices was as follows (in thousands):

Vessels	$ 94,484
Goodwill	11,693
Portable saturation system and diving equipment	9,494
Facilities, land and leasehold improvements	4,314
Customer relationships intangible asset[1]	3,698
Materials and supplies	631
Total	$ 124,314

(1) The customer relationship intangible asset is amortized over eight years on a straight-line basis, or approximately $463,000 per year.

The results of the acquired assets are included in the accompanying consolidated statements of operations in our Shelf Contracting segment since the date of the purchase. Pro forma combined operating results adjusted to reflect the results of operations of the *DLB 801* and the *Kestrel* prior to their acquisition from Acergy in January and March 2006, respectively, are not provided because the 2006 pre-acquisition results related to these vessels were immaterial to our historical results. See pro forma combined operating results of the Company and the Acergy acquisition for the years ended December 31, 2006 and 2005 below.

Subsequent to our purchase of the *DLB 801,* we sold a 50% interest in the vessel in January 2006 for approximately $19.0 million. We received $6.5 million in cash in 2005 and a $12.5 million interest-bearing promissory note in 2006. The balance of the promissory note as of December 31, 2006 was $1.5 million. We expect to collect the remaining balance. Subsequent to the sale of the 50% interest, we entered into a 10-year charter lease agreement with the purchaser, in which the lessee has an option to purchase the remaining 50% interest in the vessel beginning in January 2009. This lease was accounted for as an operating lease. Included in our lease accounting analysis was an assessment of the likelihood of the lessee performing under the full term of the lease. The carrying amount of the *DLB 801* at December 31, 2006, was approximately $17.3 million. In addition, if the lessee exercises the purchase option under the lease agreement, the lessee is able to credit $2.35 million of its lease

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payments per year against purchase price for the remaining 50% interest in the *DLB 801* not already owned. If the lessee elects not to exercise its option to purchase the remaining 50% interest in the vessel, minimum future rentals to be received on this lease are $66.2 million.

Helix Energy Limited

On November 3, 2005, we acquired Helix Energy Limited for approximately $32.7 million (approximately $27.1 million in cash, including transaction costs, and $5.6 million, at time of acquisition, in two year, variable rate notes payable to certain former owners), offset by $3.4 million of cash acquired. Helix Energy Limited is an Aberdeen, UK based provider of reservoir and well technology services to the upstream oil and gas industry with offices in London, Kuala Lumpur (Malaysia) and Perth (Australia). The acquisition was accounted for as a business purchase with the acquisition price allocated to the assets acquired and liabilities assumed as follows (in thousands):

Cash and cash equivalents	$ 3,417
Other current assets	9,786
Property and equipment, net	632
Intangibles with definite useful lives(1)	10,459
Trade name intangible(2)	6,309
Goodwill	9,549
Total assets acquired	$ 40,152
Accounts payable and accrued liabilities	$ 4,920
Deferred tax liability	2,532
Net assets acquired	$ 32,700

(1) Intangibles with definite useful lives include the following:

$1.1 million of patented technology, which is amortized over 20 years on a straight-line basis, or approximately $56,800 per year;

$6.9 million of customer relationship, which is amortized over 12 years on a straight-line basis, or approximately $578,000 per year; and

$2.4 million of non-compete intangible asset, which is amortized over 3.5 years on a straight-line basis, or approximately $683,000 per year.

(2) The trade name intangible has an indefinite useful life. It is not amortized, but is tested for impairment at least annually or when impairment indicators are present.

Resulting amounts are included in the Contracting Services segment. The final valuation of net assets was completed in 2006. The results of Helix Energy Limited are included in the accompanying statements of operations since the date of the purchase.

Pro forma combined operating results of the Company and the Remington, Murphy and Acergy acquisitions for the years ended December 31, 2006 and 2005 were presented as if the acquisitions had been completed as of January 1, 2005. The unaudited pro forma combined results were as follows (in thousands, except per share data):

	Year Ended December 31, 2006(1)	2005
Net revenues	$1,509,539	$1,337,648
Income before income taxes(2)	591,455	252,543
Net income(2)	337,885	168,316
Net income applicable to common shareholders(2)	334,527	165,862
Earnings per common share(2):		
Basic	$ 3.67	$ 1.83
Diluted	$ 3.51	$ 1.77

(1) Includes approximately $11.5 million of severance and incentive compensation expense, and approximately $20.6 million of non-cash stock compensation expense for vesting of stock options and restricted shares incurred by Remington in June 30, 2006.

(2) Includes pre-tax gain of approximately $223.1 million related to CDI s initial public offering. The

taxes associated with this gain was approximately $126.6 million.

Note 7 Details of Certain Accounts (in thousands)

Other current assets consisted of the following as of December 31, 2006 and 2005:

	2006	2005
Other receivables	$ 3,882	$ 1,386
Prepaid insurance	17,320	8,791
Other prepaids	9,174	4,391
Spare parts inventory	3,660	3,628
Current deferred tax assets	3,706	8,861
Hedging assets	5,202	
Gas imbalance	4,739	3,888
Current notes receivable	1,500	1,500
Assets held for sale	698	7,936
Other	11,651	12,534
	$ 61,532	$ 52,915

Other assets, net, consisted of the following as of December 31, 2006 and 2005:

	2006	2005
Restricted cash	$ 33,676	$ 27,010
Deposits	524	4,594
Deferred drydock expenses, net	26,405	18,285
Deferred financing costs	28,257	18,714
Intangible assets with definite lives	20,783	14,707
Intangible asset with indefinite life	6,922	6,074
Other	1,344	1,490
	$ 117,911	$ 90,874

Accrued liabilities consisted of the following as of December 31, 2006 and 2005:

	2006	2005
Accrued payroll and related benefits	$ 42,381	$ 27,982
Royalties payable	67,822	46,555
Current decommissioning liability	28,766	15,035
Hedging liability	184	8,814
Deposits		10,000
Accrued interest	15,579	2,610
Other	44,918	27,468
	$ 199,650	$ 138,464

Note 8 Equity Investments

In June 2002, we formed Deepwater Gateway, L.L.C. with Enterprise, in which we each own a 50% interest, to design, construct, install, own and operate a tension leg platform (TLP) production hub primarily for Anadarko Petroleum Corporation s *Marco Polo* field discovery in the Deepwater Gulf of Mexico. Our share of the construction costs was approximately $120 million. Our investment in Deepwater Gateway totaled $119.3 million and $117.2 million as of December 31, 2006 and 2005, respectively. Included in the investment account was capitalized interest and insurance paid by us totaling approximately $1.7 and $1.7 million, respectively. In August 2002, Enterprise and we completed a limited recourse project financing for this venture. In accordance with terms of the term loan, Deepwater

Gateway had the right to repay the principal amount plus any accrued interest due under its term loan at any time without penalty. Deepwater Gateway repaid the term loan in full in March 2005.

In December 2004, we acquired a 20% interest in Independence Hub, an affiliate of Enterprise. Independence Hub will own the Independence Hub platform to be located in Mississippi Canyon block 920 in a water depth of 8,000 feet. We account for our investment in Independence Hub under the equity method of accounting. Our investment was $82.7 million and $50.8 million as of December 31, 2006 and 2005, respectively. Our total investment is expected to be approximately $87 million. Further, we are party to a guaranty agreement with Enterprise to the extent of our ownership in Independence Hub. The agreement states, among other things, that we and Enterprise guarantee performance under the Independence Hub Agreement between Independence Hub and the producers group of exploration and production companies up to $426 million, plus applicable attorneys fees and related expenses. We have estimated the fair value of our share of the guaranty obligation to be immaterial at December 31, 2006 and 2005 based upon the remote possibility of payments being made under the performance guarantee.

In July 2005, we acquired a 40% minority ownership interest in OTSL in exchange for our DP DSV, *Witch Queen*. Our investment in OTSL totaled $10.9 million and $11.5 million at December 31, 2006 and 2005, respectively, and is part of our Shelf Contracting segment. OTSL provides marine construction services to the oil and gas industry in and around Trinidad and Tobago, as well as the U.S. Gulf of Mexico. OTSL qualified as a variable interest entity (VIE) under FIN 46. We have determined that we were not the primary beneficiary of OTSL and, thus, have not consolidated the financial results of OTSL. We account for our investment in OTSL under the equity method of accounting.

Further, in conjunction with our investment in OTSL, we entered into a one year, unsecured $1.5 million working capital loan, initially bearing interest at 6% per annum, with OTSL. Interest is due quarterly beginning September 30, 2005 with a lump sum principal payment originally due to us on June 30, 2006. We agreed to extend the lump sum principal payment due date and increased the interest rate to three-month LIBOR plus 4.0%. The note was repaid in January 2007.

In the third and fourth quarters of 2005 and first quarter of 2006, OTSL contracted the *Witch Queen* to us for certain services performed in the U.S. Gulf of Mexico. We incurred costs associated with the contract with OTSL totaling approximately $7.7 million and $11.1 million in 2006 and 2005, respectively. The charter ended in March 2006.

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 was determined to be other than temporary. In judging other than temporary, we would consider the length of time and extent to which the fair value of the investment has been less than the carrying amount of the equity investment, the near-term and longer-term operating and financial prospects of the equity company and our longer-term intent of retaining the investment in the entity. We have reported a net loss of $487,000 for the year ended December 31, 2006 related to our investment in OTSL. This net loss was an impairment indicator. However, we believe the current trend is temporary and have determined that the fair value of this investment, based on an estimate of its discounted cash flows, exceeds its carrying amount. As a result, there was no impairment at December 31, 2006.

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We made the following contributions to our equity investments during the years ended December 31, 2006, 2005 and 2004 (in thousands):

	Year Ended December 31,		
	2006	2005	2004
Deepwater Gateway, L.L.C.[1]	$	$ 72,000	$ 20,615
Independence Hub, LLC	25,578	39,060	10,585
OTSL[2]		8,400	
Total	$ 25,578	$ 119,460	$ 31,200

(1) Contribution made in the year ended December 31, 2005 related to Deepwater Gateway was for the repayment of our portion of the term loan for Deepwater Gateway. Upon repayment of the loan, our $7.5 million restricted cash in 2005 was released from escrow and the escrow agreement was terminated.

(2) Includes non-cash contribution of the *Witch Queen* in 2005 of $6.7 million (net of $296,000 of transaction costs).

We received the following distributions from our equity investments during the years ended December 31, 2006, 2005 and 2004 (in thousands):

Year Ended December 31,

	2006	2005	2004
Deepwater Gateway, L.L.C.	$ 16,250	$ 21,100	$ 7,500
Independence Hub, LLC			
OTSL			
Total	$ 16,250	$ 21,100	$ 7,500

Note 9 Consolidated Variable Interest Entities

In October 2006, we, along with Kommandor RØMØ, a Danish corporation, formed Kommandor, a Delaware limited liability company, to initially convert a ferry vessel into a dynamically-positioned construction services vessel. Upon completion of the initial conversion, this vessel will be leased under a bareboat charter to us for further conversion and subsequent use as a floating production system in the Deepwater Gulf of Mexico, initially for the *Phoenix* field. Our initial investment for our 50% interest in Kommandor was $15 million. Further, we have agreed to provide a loan facility of up to $40 million and Kommandor RØMØ has agreed to loan $5 million to the newly formed entity for purposes of completing the initial conversion. Kommandor has received a commitment letter from a financial institution for term financing for $60 million of the initial conversion upon delivery of the vessel under the bareboat charter. Proceeds from this financing will be used to repay amounts loaned to Kommandor by us and Kommandor RØMØ. Conversion of the vessel is expected to be completed in two phases. The first phase is expected to be completed by the end of 2007. The second phase of the conversion is expected to be completed by mid 2008. Estimated cost of conversion for the second phase is approximately $100 million, in which we expect to participate 100%.

In addition, per the operating agreement, 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 at the time the put or call is exercised to be approximately $23.8 million.

Kommandor qualified as a VIE under FIN 46. We determined that we were the primary beneficiary of Kommandor and, thus, have consolidated the financial results of Kommandor as of

December 31, 2006. The results of Kommandor are included in our Production Facilities segment. Kommandor is a development stage enterprise since its formation in October 2006.

Note 10 Long-Term Debt

Senior Credit Facilities

On July 3, 2006, we entered into a Credit Agreement (the Credit Agreement) with Bank of America, N.A., as administrative agent and as lender, together with the other lenders (collectively, the Lenders). Under the Credit Agreement, we borrowed $835 million in a term loan (the Term Loan) and may borrow revolving loans (the Revolving Loans) under a revolving credit facility up to an outstanding amount of $300 million (the Revolving Credit Facility). In addition, the Revolving Credit Facility may be used for issuances of letters of credit up to an outstanding amount of $50 million. The proceeds from the Term Loan were used to fund the cash portion of the Remington acquisition.

The Term Loan and the Revolving Loans (together, the Loans) will, at our election, bear interest either in relation to Bank of America s base rate or to LIBOR. The Term Loan or portions thereof bear interest at one, three or six month LIBOR at our election plus a margin of 2.00%. Our current election is to bear interest based on LIBOR. Our interest rate for year ended December 31, 2006 was approximately 7.4% (including the effects of our interest rate swaps). The Revolving Loans or portions thereof bearing interest at LIBOR will bear interest based on one, three or six month LIBOR at our election plus a margin ranging from 1.00% to 2.25%. Margins on the Revolving Loans will fluctuate in relation to the consolidated leverage ratio as provided in the Credit Agreement.

The Term Loan matures on July 1, 2013 and is subject to scheduled principal payments of $2.1 million quarterly. 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 did not have any amount outstanding under the Revolving Loans at December 31, 2006. 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 excess will be applied to the Revolving Loans, if any.

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 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, 2006, we were in compliance with these 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 Cal Dive, and are secured by a lien on substantially all of our assets and properties and all of the assets and properties of our U.S. subsidiaries, other than those of Cal Dive. 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 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 the Term Loan are subject to market influences and will vary over the term of the agreement, we entered into various interest rate swaps for $200 million of notional value effective as of October 3, 2006. These hedges are designated as cash flow hedges and qualify for hedge accounting. Under the swaps we receive interest based on three-month LIBOR and pay interest quarterly at an average annual fixed rate of 5.131% which began in October 2006. The objective of the hedge is to eliminate the variability of cash flows in the interest payments for up to $200 million of our Term Loan. Changes in the cash flows of the interest rate swap are expected to exactly offset the changes in cash flows (i.e., changes in interest rate payments) attributable to fluctuations in LIBOR on up to $200 million of our Term Loan.

Cal Dive International, Inc. Revolving Credit Facility

In November 2006, CDI entered into a five-year $250 million revolving credit facility with certain financial institutions. The loans mature in November 2011. Loans under this facility are non-recourse to Helix. Loans under the revolving credit facility may consist of loans bearing interest in relation to the Federal Funds Rate or to the lender s base rate, known as Base Rate Loans, and loans bearing interest in relation to a LIBOR rate, known as LIBOR Rate Loans. Assuming there is no event of default, Base Rate Loans will bear interest at a per annum rate equal to the base rate plus a margin ranging from 0% to 0.5%, while LIBOR Rate Loans will bear interest at the LIBOR rate plus a margin ranging from 0.625% to 1.75%.

The credit agreement and the other documents entered into in connection with the credit agreement include terms and conditions, including covenants. The covenants include restrictions on the CDI s 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. At December 31, 2006, CDI was in compliance with all debt covenants. The credit facility is secured by vessel mortgages on five of CDI s vessels, a pledge of all of the stock of all of CDI s domestic subsidiaries and 65% of the stock of one of CDI s foreign subsidiaries, and a security interest in, among other things, all of CDI s equipment, inventory, accounts and general tangible assets.

During December 2006, CDI borrowed $201 million under the revolving credit facility and distributed $200 million of those proceeds to us as a dividend. At December 31, 2006, CDI had outstanding debt of $201 million under this credit facility. CDI expects to use the remaining availability under the revolving credit facility for working capital and other general corporate purposes. We do not have access to any unused portion of CDI s revolving credit facility.

Convertible Senior Notes

On March 30, 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 paid on December 8, 2005, effective as of December 2, 2005, the initial conversion rate of the Convertible Senior Notes of 15.56, which was equivalent to a conversion price of approximately $64.27 per share of common stock, was changed to 31.12 shares of common stock per $1,000 principal amount of the Convertible Senior Notes, which is equivalent to a conversion price of approximately $32.14 per share of common stock. We may redeem the Convertible Senior Notes on or after December 20, 2012. Beginning with the period commencing on December 20, 2012 to June 14, 2013 and for each six-month period thereafter, in addition to the stated interest rate of 3.25% per annum, we will pay contingent interest of 0.25% of the market value of the Convertible Senior Notes if, during specified testing periods, the average trading price of the Convertible Senior Notes exceeds 120% or more of the principal value. In addition, holders of the Convertible Senior Notes may require us to repurchase the notes at 100% of the principal amount on each of December 15, 2012, 2015, and 2020, and upon certain events.

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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. During 2006 and 2005, no conversion triggers were met.

Approximately 1.0 million and 118,000 shares underlying the Convertible Senior Notes were included in the calculation of diluted earnings per share for the year ended December 31, 2006 and 2005, respectively, because our weighted average share price for each period was above the conversion price of approximately $32.14 per share. As a result, there would be a premium over the principal amount, which is paid in cash, and the shares would be issued on conversion. The maximum number of shares of common stock which may be issued upon conversion of the Convertible Senior Notes is 13,303,770. In addition to the 13,303,770 shares of common stock registered, we registered 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 for general corporate purposes including 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 (Torch and Acergy vessels and Murphy oil and gas properties).

MARAD Debt

At December 31, 2006 and 2005, $131.3 million and $134.9 million, respectively, was outstanding on our long-term financing 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. As of December 31, 2006 and 2005, we were in compliance with these covenants.

In September 2005, we entered into an interest rate swap agreement with a bank. The swap was designated as a cash flow hedge of a forecasted transaction in anticipation of the refinancing of the MARAD Debt from floating rate debt to fixed-rate debt that closed on September 30, 2005. The interest rate swap agreement totaled an aggregate notional amount of $134.9 million with a fixed interest rate of 4.695%. On September 30, 2005, we terminated the interest rate swap and received cash proceeds of approximately $1.5 million representing a gain on the interest rate differential. This gain was deferred and is being amortized over the remaining life of the MARAD Debt as an adjustment to interest expense.

Other

In connection with the acquisition of Helix Energy Limited, we entered into a two-year note payable to the former owners totaling approximately 3.1 million British Pounds, or approximately $5.6 million, on November 3, 2005 (approximately $6.2 million and $5.4 million at December 31, 2006 and 2005, respectively). The notes bear interest at a LIBOR based floating rate with interest payments due quarterly beginning January 1, 2006. Principal amounts are due in November 2007.

In August 2003, Canyon Offshore, Ltd. (a U.K. subsidiary COL) (with a parent guaranty from Helix) completed a capital lease with a bank refinancing the construction costs of certain assets. COL received proceeds of $12 million for the assets and agreed to pay the bank sixty monthly installment payments of $217,174 (resulting in an implicit interest rate of 3.29%) and has an option to purchase the assets at the end of the lease term for $1. No gain or loss resulted from this transaction. The proceeds were used to reduce our revolving credit facility, which had initially funded the construction costs of the assets. This transaction was accounted for as a capital lease.

In connection with borrowings under our long-term debt financings described above, we paid deferred financing cost of $11.8 million and $8.8 million during the years ended December 31, 2006 and 2005, respectively. Deferred financing costs of $28.3 million and $18.7 million are included in Other Assets, Net (see Note 7 Detail of Certain Accounts) as of December 31, 2006 and 2005, respectively, and are being amortized over the life of the respective agreement.

Scheduled maturities of long-term debt and capital lease obligations outstanding as of December 31, 2006 were as follows (in thousands):

	Term Loan	CDI Revolving Credit Facility	Convertible Senior Notes	MARAD Debt	Loan Notes(1)	Capital Leases	Total
Less than one year	$ 8,400	$	$	$ 3,823	$ 11,146	$ 2,519	$ 25,888
One to two years	8,400			4,014		1,505	13,919
Two to Three years	8,400			4,214			12,614
Three to four years	8,400			4,424			12,824
Four to five years	8,400	201,000		4,645			214,045
Over five years	790,900		300,000	110,166			1,201,066
Long-term debt	832,900	201,000	300,000	131,286	11,146	4,024	1,480,356
Current maturities	(8,400)			(3,823)	(11,146)	(2,519)	(25,888)
Long-term debt, less current maturities	$ 824,500	$ 201,000	$ 300,000	$ 127,463	$	$ 1,505	$ 1,454,468

(1) Includes the $5 million loan provided by

Kommandor RØMØ to Kommandor as of December 31, 2006. The loan is expected to be repaid at the completion of the initial conversion, which is forecasted to be the end of 2007. As such, the entire loan amount is classified as current.

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We had unsecured letters of credit outstanding at December 31, 2006 totaling approximately $5.3 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, 2006, 2005 and 2004 (in thousands):

	Year Ended December 31,		
	2006	2005	2004
Interest expense	$ 51,913	$ 14,970	$ 6,282
Interest income	(6,259)	(5,917)	(439)
Capitalized interest	(10,609)	(2,025)	(243)
Interest expense, net	$ 35,045	$ 7,028	$ 5,600

Note 11 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. 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,		
	2006	2005	2004
Statutory rate	35.0%	35.0%	35.0%
Gain on subsidiary equity transaction	8.0		
Foreign provision	(0.2)		0.9
Percentage depletion in excess of basis	(0.1)	(0.7)	
Research and development tax credits			(1.3)
IRC Section 199 deduction	(0.2)	(0.5)	
Other		(0.8)	(0.4)
Effective rate	42.5%	33.0%	34.2%

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

	Year Ended December 31,		
	2006	2005	2004
Current	$ 199,921	$ 32,291	$ 988
Deferred	57,235	42,728	42,046
	$ 257,156	$ 75,019	$ 43,034

Year Ended December 31,		
2006	2005	2004

Domestic	$ 247,588	$ 68,957	$ 41,260
Foreign	9,568	6,062	1,774
	$ 257,156	$ 75,019	$ 43,034

In 2006 and 2005, our oil and gas activities and certain construction activities qualified for a tax deduction under Internal Revenue Code (IRC) Section 199. In addition, due to our taxable income position at December 31, 2006 and 2005, the IRC allowed a deduction for percentage depletion in excess of basis on our oil and gas activities.

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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 carryforward as of the acquisition date. As a result of our taxable income position during 2006, we were able to utilize $61.0 million of the net operating loss carryforward at December 31, 2006. A valuation reserve was determined not to be necessary.

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, 2006 and 2005 was as follows (in thousands):

	2006	2005
Deferred tax liabilities:		
Depreciation	$ 416,762	$ 159,360
Equity investments in production facilities	30,723	28,264
Prepaid and other	31,383	10,693
Total deferred tax liabilities	$ 478,868	$ 198,317
Deferred tax assets:		
Net operating loss carryforward	$ (3,888)	$ (2,079)
Decommissioning liabilities	(33,367)	(26,915)
Reserves, accrued liabilities and other	(8,775)	(10,537)
Total deferred tax assets	$ (46,030)	$ (39,531)
Net deferred tax liability	$ 432,838	$ 158,786

At December 31, 2006 and 2005, we had $4.9 million and $6.9 million of net operating losses, respectively that were incurred in the United Kingdom. The utilization of these net operating losses is restricted to the entity generating the loss. The U.K. losses have an indefinite carryforward period.

We consider the undistributed earnings of our principal non-U.S. subsidiaries to be permanently reinvested. At December 31, 2006 and 2005, our principal non-U.S. subsidiaries had accumulated earnings and profits of approximately $20.3 million and a $4.3 million deficit, respectively. We have not provided deferred U.S. income tax on the accumulated earnings and profits.

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 the next 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, 2006, this agreement did not have a material impact on our consolidated results of operations.

Note 12 Convertible Preferred Stock

On January 8, 2003, we completed the private placement of $25 million of a newly designated class of cumulative convertible preferred stock (Series A-1 Cumulative Convertible Preferred Stock, par value $0.01 per share) that is convertible into 1,666,668 shares of our common stock at $15 per share. The preferred stock was issued to a private investment firm. Subsequently in June 2004, the preferred stockholder exercised its existing right and purchased $30 million in additional cumulative convertible preferred stock (Series A-2 Cumulative Convertible Preferred Stock, par value $0.01 per share). In accordance with the January 8, 2003 agreement, the $30 million in additional preferred stock is convertible into 1,964,058 shares of our common stock at $15.27 per share. In the event the holder of the convertible preferred stock elects to redeem into our common stock and our common stock price is below the conversion prices, unless we have elected to settle in cash, the holder would receive additional shares above the 1,666,668 common shares (Series A-1 tranche) and 1,964,058 common shares (Series A-2 tranche). The incremental shares would be treated as a dividend and reduce net income applicable to common shareholders.

The preferred stock has a minimum annual dividend rate of 4%, subject to adjustment, payable quarterly in cash or common shares at our option. The dividend rate for the years ended December 31, 2006, 2005 and 2004 was 6.9%, 5.9% and 4.0%, respectively. We paid these dividends in 2006, 2005 and 2004 in cash. The holder may redeem the value of its original and additional investment in the preferred shares to be settled in common stock at the then prevailing market price or cash at our discretion. In the event we are unable to deliver registered common shares, we could be required to redeem 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 price ($15.00 and $15.27).

Note 13 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 $2.3 million, $963,000 and $691,000 for the years ended December 31, 2006, 2005 and 2004, respectively.

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). Under the 1995 Incentive Plan, a maximum of

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10% of the total shares of common stock issued and outstanding may 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 on May 10, 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 8, 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, stock and cash awards. Awards granted to employees under the 1995 and 2005 Incentive Plan typically vest 20% per year for 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.

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.

On January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123 (Revised 2004) *Share-Based Payments* (SFAS 123R) and began accounting for our stock-based compensation plans under the fair value method. 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 have selected 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. The adoption did not have a material impact on our consolidated results of operations, earnings per share and cash flows. There were no stock option grants in 2006 or 2005.

Stock Options

The options outstanding at December 31, 2006, have exercise prices as follows: 163,000 shares at $8.57; 67,510 shares at $9.32; 110,680 shares at $10.92; 73,000 shares at $10.94; 64,800 shares at $11.00; 181,280 shares at $12.18; 70,400 shares at $13.91; and 152,400 shares ranging from $8.14 to $12.00, and a weighted average remaining contractual life of 5.75 years.

Options outstanding are as follows:

	2006		2005		2004	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Options outstanding at beginning of year	1,717,904	$10.91	2,599,894	$10.65	3,446,204	$10.19
Granted		$		$	337,000	$12.63
Exercised	(792,394)	$11.21	(858,070)	$10.17	(1,119,818)	$ 9.85
Terminated	(42,440)	$10.96	(23,920)	$10.82	(63,492)	$10.43
Options outstanding at end of year	883,070	$10.86	1,717,904	$10.91	2,599,894	$10.65
Options exercisable end of year	515,318	$10.34	1,066,316	$10.94	1,428,348	$10.58

For the year ended December 31, 2006, $1.4 million was recognized as compensation expense related to stock options. No expense related to stock options was recognized in 2005 and 2004 under the intrinsic value method. The aggregate intrinsic value of the stock options exercised in 2006, 2005 and 2004 was approximately $21.3 million, $12.6 million and $5.3 million, respectively. Future compensation cost associated with unvested options at December 31, 2006 totaled approximately $1.8 million. The aggregate intrinsic value of options exercisable at December 31, 2006 was approximately $10.8 million. The weighted average vesting period related to nonvested stock options at December 31, 2006 was approximately 1.7 years.

Restricted Shares

We grant restricted shares to members of our board of directors, key executives and selected management employees. Compensation cost for each award is the product of 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, 2006 and 2005 (no restricted shares were granted prior to 2005):

	2006		2005	
	Shares	Grant Date Fair Value(1)	Shares	Grant Date Fair Value(1)
Restricted shares outstanding at beginning of year	384,902	$25.59		$
Granted	497,450	$37.07	388,350	$ 25.56
Vested	(66,865)	$24.51		$
Forfeited	(86,275)	$36.04	(3,448)	$ 21.86
Restricted shares outstanding at end of year,	729,212	$32.29	384,902	$ 25.59

(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 year ended December 31, 2005, the amounts granted were recorded as unearned compensation, a component of shareholders equity and charged to expense over the respective vesting periods on a straight-line basis. Amortization of unearned compensation totaled $1.4 million for the year ended December 31, 2005. The balance in unearned compensation at December 31, 2005 was $7.5 million and was reversed in January 2006 upon adoption of the fair value method. For the year ended December 31, 2006, $6.3 million was recognized as compensation expense related to restricted shares. Future compensation cost associated with unvested restricted stock awards at December 31, 2006 totaled approximately $17.5 million. The weighted average vesting period related to nonvested restricted stock awards at December 31, 2006 was approximately 3.8 years.

In January and February 2007, we granted certain key executives and select management employees 675,190 restricted shares under the 2005 Long-Term Incentive Plan. The shares vest 20% per year for a five-year period. The weighted average market value of the restricted shares was $31.49 per share or $21.3 million. We also granted our outside directors 2,092 restricted shares. The shares vest on January 1, 2009. The market value of the restricted shares was $31.37 per share or $66,000.

Employee Stock Purchase Plan

Effective May 12, 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 percent 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 10 percent of an employee s base salary. Under this plan 97,598, 79,878 and 93,580 shares of common stock were purchased in the open market for our employees at a weighted-average share price of $33.12, $23.11 and $13.58 during 2006, 2005 and 2004, respectively. For the year ended December 31, 2006, we recognized $1.6 million of compensation expense related to stock purchased under the ESPP. No expenses related to the ESPP were recognized in 2005 and 2004 under the intrinsic value method.

In January 2007, we issued 109,754 shares of our common stock to our employees under this plan to satisfy the employee purchase period from July 1, 2006 to December 31, 2006, which increased our common stock outstanding. We subsequently repurchased the same number of shares of our common stock in the open market at $29.94 per share and reduced the number of shares of our common stock outstanding.

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 14 Shareholders Equity

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

In November 2005, our Board of Directors declared a two-for-one split of our common stock in the form of a 100% stock distribution on December 8, 2005 to all holders of record at the close of business on December 1, 2005. All share and per share data in these financial statements have been restated to reflect the stock split.

The components of accumulated other comprehensive income (loss) as of December 31, 2006 and 2005 were as follows (in thousands):

	2006	2005
Cumulative foreign currency translation adjustment	$ 24,580	$ 6,979
Unrealized gain (loss) on hedges, net	2,656	(8,708)
Accumulated other comprehensive income (loss)	$ 27,236	$ (1,729)

Note 15 Stock Buyback Program

On June 28, 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.

Note 16 Related Party Transactions

Cal Dive International, Inc.

Before the IPO of Cal Dive, we provided to 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 $16.5 million, $8.5 million and $7.3 million for the years ended December 31, 2006, 2005 and 2004, respectively.

Included in these costs are costs related to the participation by CDI s employees in our employee benefit plans through December 31, 2006, 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 $5.8 million, $3.3 million and $2.5 million for the years ended December 31, 2006, 2005 and 2004, respectively. Our defined contribution 401(k) retirement plan is further disclosed in Note 13 .

In addition, 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 $5.6 million, $4.1 million and $3.2 million for the years ended December 31, 2006, 2005 and 2004, 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 those 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. 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 50% or more 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 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.

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 permits CDI employees to participate in our Employee Stock Purchase Plan for the offering period that ends June 30, 2007, and CDI agrees to pay us at the end of the offering period 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 11 Income Taxes 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 Oil & Gas Corp. 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 began in December 2003. Payments to OKCD from us totaled $34.6 million, $28.1 million and $20.3 million in the years ended December 31, 2006, 2005 and 2004, respectively. Our Principal Executive Officer, as a Class A limited partner of OKCD, personally owns approximately 67% of the partnership. Other executive officers of the Company own approximately 6% combined of the partnership. In 2000, OKCD also awarded Class B limited partnership interests to key Helix employees.

In connection with the acquisition of Helix Energy Limited, we entered into two-year notes payable to former owners totaling approximately 3.1 million British Pounds, or approximately $5.6 million, on November 3, 2005 (approximately $6.2 million and $5.4 million at December 31, 2006 and 2005). The notes bear interest at a LIBOR based floating rate with payments due quarterly beginning January 31, 2006. Principal amounts are due in November 2007.

Note 17 Commitments and Contingencies

Lease Commitments

We lease several facilities, ROVs and a vessel under noncancelable operating leases. Future minimum rentals under these leases are approximately $63.0 million at December 31, 2006 with $32.2 million due in 2007, $10.6 million in 2008, $10.1 million in 2009, $3.0 million in 2010, $2.4 million in 2011 and $4.7 million thereafter. Total rental expense under these operating leases was approximately $25.3 million, $23.4 million and $8.9 million for the years ended December 31, 2006, 2005 and 2004, respectively.

Insurance

We carry Hull and Increased Value insurance which provides coverage for physical damage 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 $500,000 on the *Intrepid, Seawell, Express* and *Kestrel.* Other vessels carry deductibles between $250,000 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 $1.0 million annual aggregate. In addition to the liability policies named above, we carry various layers of Umbrella Liability for total limits of $300,000,000 excess of primary limits. Our self-insured retention on our medical and health benefits program for employees is

$130,000 per participant.

We incur workers compensation and other insurance claims in the normal course of business, which management believes are covered by insurance. Our insurers, legal counsel and we analyze each claim for potential exposure and estimate the ultimate liability of each claim. Amounts accrued and receivable from insurance companies, above the applicable deductible limits, are reflected in Other Current Assets in the consolidated balance sheet. Such amounts were $3.6 million and $6.1 million as of December 31, 2006 and 2005, respectively. See related accrued liabilities at Note 7 Detail of Certain Accounts . 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

We are involved in various legal proceedings, primarily involving claims for personal injury under the General Maritime Laws of the United States and the Jones Act 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. In that regard, in 1998, one of our subsidiaries, Cal Dive Offshore Ltd (CDO), entered into a subcontract with Seacore Marine Contractors Limited (Seacore) to provide a vessel to Seacore for Seacore s use in performing a contract with Coflexip Stena Offshore Newfoundland (Coflexip) in Canada. Due to various difficulties, that contract was terminated and an arbitration to recover damages was commenced. We were not a party to that arbitration. A liability finding was made by the arbitrator against Seacore and in favor of Coflexip. Seacore and Coflexip settled this matter with Seacore paying Coflexip CAD$6.95 million. Seacore then initiated an arbitration proceeding against CDO seeking payment of that amount, and subsequently commenced a lawsuit against us seeking the same recovery. Recently we have settled this litigation and arbitration with us making a payment to Seacore in the amount of CAD$825,000 (or approximately $703,000) and the parties fully and finally releasing each other from all claims pertaining to the matter.

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 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. Our only leases affected by this dispute are the *Gunnison* leases. 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. 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 Oil and Gas Corporation (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, such as ours. We do not anticipate that the MMS director will issue decisions in ours or the other companies administrative appeals until the Kerr-McGee litigation has been resolved. As a result of this dispute, we have recorded reserves for the disputed royalties (and any other royalties that may be claimed) plus interest at 5% for our portion of the *Gunnison* related MMS claim. The total reserved amount at December 31, 2006 was approximately $42.6 million. At this time, it is not anticipated that any penalties would be assessed even if we are unsuccessful in its appeal.

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.

Commitments

We plan to convert the *Caesar* (acquired in January 2006 for $27.5 million in cash) into a deepwater pipelay vessel. Total conversion costs are estimated to be approximately $110 million, of which approximately $15.0 million had been incurred, with an additional $52.2 million committed at December 31, 2006. In addition, we will upgrade the *Q4000* to include drilling via the addition of a modular-based drilling system for approximately $40 million, of which approximately $15.3 million had been incurred, with an additional $19.0 million committed at December 31, 2006.

In addition, in September 2006, we announced our plan to commit to the construction of a $160 million multi-service dynamically positioned dive support/ well intervention vessel (*Well Enhancer*) that will be capable of working in the North Sea and West of Shetlands to support our contract extension to provide light well intervention services for Shell UK Ltd. We expect the *Well Enhancer* to join our fleet in 2008. At December 31, 2006, we had incurred approximately $19.4 million, with an additional $87.3 million committed to this project.

Further, we, along with Kommandor RØMØ, have begun the conversion of a ferry vessel into a dynamically-positioned construction services vessel. Conversion of the vessel is expected to be completed in two phases. The first phase of the conversion is estimated to be approximately $60 million and is expected to be completed by the end of 2007. As of December 31, 2006, $16.8 million had been incurred related to the conversion (our portion was $8.4 million), with an additional $14.0 million committed. The second phase of the conversion into a minimal floating production system, *Helix Producer I*, is expected to be completed by mid 2008. Estimated cost of conversion for the second phase is approximately $100 million, in which we expect to fund 100%. See Note 9 Consolidated Variable Interest Entities for a detailed discussion of Kommandor.

As of December 31, 2006, we have also committed approximately $138.9 million in additional capital expenditures for exploration, development and drilling costs related to our oil and gas properties.

Note 18 Business Segment Information

Our operations are conducted through the following lines of businesses: contracting services operations and oil and gas operations. We have disaggregated our contracting services operations into three reportable segments in accordance with SFAS 131: Contracting Services, Shelf Contracting and Production Facilities. As a result, our reportable segments consist of the following: Contracting Services (formerly known as Deepwater Contracting), Shelf Contracting, Oil and Gas (formerly known as Oil and Gas Production) and Production Facilities. Contracting Services operations include deepwater pipelay, well operations, robotics and reservoir and well tech services. Shelf Contracting operations consist of assets deployed primarily for diving-related activities and shallow water construction. See Note 3 for discussion of initial public offering of CDI common stock (represented by the Shelf Contracting segment). 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 was consolidated in accordance with FIN 46 and is included in our Production Facilities segment.

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The following summarizes certain financial data by business segment:

	Year Ended December 31,		
	2006	2005	2004
	(in thousands)		
Revenues			
Contracting Services	$ 485,246	$ 328,315	$ 197,688
Shelf Contracting	509,917	223,211	126,546
Oil and Gas	429,607	275,813	243,310
Intercompany elimination	(57,846)	(27,867)	(24,152)
Total	$ 1,366,924	$ 799,472	$ 543,392
Income from operations			
Contracting Services	$ 90,454	$ 42,333	$ (8,825)
Shelf Contracting(1)(2)	184,879	60,078	14,692
Oil and Gas	132,104	123,104	117,682
Production Facilities(3)	(1,051)	(977)	(345)
Intercompany elimination	(8,024)		(173)
Total	$ 398,362	$ 224,538	$ 123,031
Net interest expense and other			
Contracting Services(5)	$ 36,076	$ 8,571	$ 4,663
Shelf Contracting	(163)	(45)	
Oil and Gas	(1,339)	(1,117)	602
Production Facilities	60	150	
Total	$ 34,634	$ 7,559	$ 5,265
Equity in earnings of production facilities investments	$ 18,413	$ 10,608	$ 7,927
Income before income taxes			
Contracting Services(4)	$ 277,512	$ 33,762	$ (13,488)
Shelf Contracting(1)(2)	185,042	60,123	14,692
Oil and Gas	133,443	124,221	117,080
Production Facilities(3)	17,302	9,481	7,582
Intercompany elimination	(8,024)		(173)
Total	$ 605,275	$ 227,587	$ 125,693
Provision for income taxes			
Contracting Services	$ 140,306	$ 9,949	$ (7,574)
Shelf Contracting	65,710	21,009	5,166

Oil and Gas	45,084	40,734	42,787
Production Facilities	6,056	3,327	2,655
Total	$ 257,156	$ 75,019	$ 43,034

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Identifiable assets			
Contracting Services	$ 1,313,206	$ 736,852	$ 597,257
Shelf Contracting	452,153	277,446	145,226
Oil and Gas	2,282,715	478,522	229,083
Production Facilities	242,113	168,044	67,192
Total	$ 4,290,187	$ 1,660,864	$ 1,038,758
Capital expenditures			
Contracting Services	$ 130,938	$ 90,037	$ 21,016
Shelf Contracting	38,086	32,383	1,792
Oil and Gas	282,318	238,698	27,315
Production Facilities	45,327	111,429	32,206
Total	$ 496,669	$ 472,547	$ 82,329
Depreciation and amortization			
Contracting Services	$ 34,165	$ 25,102	$ 20,227
Shelf Contracting[(1)]	24,515	15,734	19,032
Oil and Gas	134,967	70,637	69,046
Total	$ 193,647	$ 111,473	$ 108,305

(1) Included pre-tax $790,000 and $3.9 million of asset impairment charges in 2005 and 2004, respectively.

(2) Included $(487,000) and $2.8 million equity in (losses) earnings from investment in OTSL in 2006 and 2005, respectively.

(3)

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

(4) Includes 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.

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

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Intercompany segment revenues during the years ended December 31, 2006, 2005 and 2004 were as follows:

	Year Ended December 31,		
	2006	2005	2004
Contracting Services	$ 42,585	$ 26,431	$ 22,246
Shelf Contracting	15,261	1,436	1,906
Total	$ 57,846	$ 27,867	$ 24,152

Intercompany segment profit (which only relates to intercompany capital projects) during the years ended December 31, 2006, 2005 and 2004 were as follows:

	Year Ended December 31,		
	2006	2005	2004
Contracting Services	$ 2,460	$	$ 91
Shelf Contracting	5,564		82
Total	$ 8,024	$	$ 173

During the years ended December 31, 2006, 2005 and 2004, we derived approximately $190.1 million, $83.2 million and $77.1 million, respectively, of our revenues from the U.K. sector utilizing approximately $238.5 million, $168.4 million and $136.7 million, respectively, of our total assets in this region. The majority of the remaining revenues were generated in the U.S. Gulf of Mexico.

Note 19 Allowance for Uncollectible Accounts

The following table sets forth the activity in our Allowance for Uncollectible Accounts for each of the three years in the period ended December 31, 2006 (in thousands):

	Year Ended December 31,		
	2006	2005	2004
Beginning balance	$ 585	$ 7,768	$ 7,462
Additions	3,598	2,577	2,745
Deductions	(3,201)	(9,760)	(2,439)
Ending balance	$ 982	$ 585	$ 7,768

See Note 2 Summary of Significant Accounting Policies for a detailed discussion regarding our accounting policy on Accounts Receivable and Allowance for Uncollectible Accounts.

Note 20 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* (in thousands).

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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:

	2006	2005
Unproved oil and gas properties	$ 101,845	$
Proved oil and gas properties	1,576,742	475,583
Total oil and gas properties	1,678,587	475,583
Accumulated depletion, depreciation and amortization	(335,112)	(160,651)
Net capitalized costs	$ 1,343,475	$ 314,932

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, 2006 and 2005, our oil and gas operations decommissioning liabilities were $167.7 million and $121.4 million, respectively.

Costs Incurred in Oil and Gas Producing Activities

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

	United States	United Kingdom	Total
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**
Year Ended December 31, 2005			
Property acquisition costs:			
Proved properties	$ 183,837	$	$ 183,837
Unproved properties			
Total property acquisition costs	183,837		183,837
Exploration costs	5,728		5,728

Development costs[1]		67,193				67,193
Asset retirement cost		36,119				36,119
Total costs incurred	**$**	**292,877**	**$**		**$**	**292,877**
Year Ended December 31, 2004						
Property acquisition costs:						
Proved properties	$		$		$	
Unproved properties						
Total property acquisition costs						
Exploration costs						
Development costs[1]		38,171				38,171
Asset retirement cost		202				202
Total costs incurred	**$**	**38,373**	**$**		**$**	**38,373**

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(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

	United States	United Kingdom	Total
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**
Year Ended December 31, 2005			
Revenues	$ 275,813	$	$ 275,813
Production (lifting) costs	56,235		56,235
Exploration expenses(2)	6,465		6,465
Depreciation, depletion, amortization and accretion	70,637		70,637
Selling and administrative	19,372		19,372
Pretax income from producing activities	123,104		123,104
Income tax expense	40,734		40,734
Results of oil and gas producing activities(1)	**$ 82,370**	**$**	**$ 82,370**
Year Ended December 31, 2004			
Revenues	$ 243,310	$	$ 243,310
Production (lifting) costs	39,410		39,410

Depreciation, depletion, amortization and accretion	69,046		69,046
Selling and administrative	17,789		17,789
Pretax income from producing activities	117,065		117,065
Income tax expense	42,787		42,787
Results of oil and gas producing activities[1]	**$ 74,278**	**$**	**$ 74,278**

(1) Excludes net interest expense and other.

(2) See Note 5 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 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 (140 fields as of December 31, 2006). 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 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 they had satisfactorily resolved their 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 performed 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 together with a percentage of the 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 83% of the total discounted future net revenues. Huddleston audited approximately 81% of our total reserve base in the United States, including what was deemed to be the most valuable properties. Huddleston audited 76% of proved developed reserves and 85% of the proved undeveloped reserves totaling 81% of both categories combined. Huddleston also analyzed the methods utilized by us in the preparation of all of the estimated reserves and revenues. Huddleston s audit report represents they believe 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.

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

	United States	United Kingdom	Total
Total proved reserves at December 31, 2003	**12,521**		**12,521**
Revision of previous estimates	(1,412)		(1,412)
Production	(2,593)		(2,593)
Purchases of reserves in place			
Sales of reserves in place	(1)		(1)
Extensions and discoveries	2,002		2,002
Total proved reserves at December 31, 2004	**10,517**		**10,517**
Revision of previous estimates	(403)		(403)
Production	(2,473)		(2,473)
Purchases of reserves in place	6,653		6,653
Sales of reserves in place			
Extensions and discoveries	579		579
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**
Total proved developed reserves as of :			
December 31, 2003	4,913		4,913
December 31, 2004	6,429		6,429
December 31, 2005	7,759		7,759
December 31, 2006	13,328		13,328

(1) Proved reserves at December 31, 2006 includes approximately 17,573 MBbls acquired from the Remington acquisition.

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

	United States	United Kingdom	Total
Total proved reserves at December 31, 2003	**74,660**		**74,660**
Revision of previous estimates	(2,184)		(2,184)
Production	(25,957)		(25,957)
Purchases of reserves in place			
Sales of reserves in place	(697)		(697)
Extensions and discoveries	7,382		7,382
Total proved reserves at December 31, 2004	**53,204**		**53,204**
Revision of previous estimates	(1,124)		(1,124)
Production	(18,137)		(18,137)
Purchases of reserves in place	91,089		91,089
Sales of reserves in place			
Extensions and discoveries	11,041		11,041
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**
Total proved developed reserves as of :			
December 31, 2003	45,773		45,773
December 31, 2004	36,362		36,362
December 31, 2005	55,321		55,321
December 31, 2006	156,251		156,251

(1) Proved reserves at December 31, 2006 includes approximately 159,338 MMcf acquired from the Remington acquisition.

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Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following table reflects the standardized measure of discounted future net cash flows relating to our interest in proved oil and gas reserves:

	United States	United Kingdom	Total
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**
As of December 31, 2005			
Future cash inflows	$ 2,131,985	$	$ 2,131,985
Future costs:			
Production	(311,163)		(311,163)
Development and abandonment	(450,558)		(450,558)
Future net cash flows before income taxes	1,370,264		1,370,264
Future income tax expense	(433,335)		(433,335)
Future net cash flows	936,929		936,929
Discount at 10% annual rate	(209,867)		(209,867)
Standardized measure of discounted future net cash flows	**$ 727,062**	**$**	**$ 727,062**
As of December 31, 2004			
Future cash inflows	$ 756,668	$	$ 756,668
Future costs:			
Production	(125,350)		(125,350)
Development and abandonment	(146,131)		(146,131)
Future net cash flows before income taxes	485,187		485,187
Future income tax expense	(144,263)		(144,263)
Future net cash flows	340,924		340,924
Discount at 10% annual rate	(54,185)		(54,185)
Standardized measure of discounted future net cash flows	**$ 286,739**	**$**	**$ 286,739**

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. See the following table for base prices used in determining the standardized measure:

	United States	United Kingdom	Total
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
Year Ended December 31, 2005			
Average oil price per Bbl	$59.82	$	$59.82
Average gas prices per Mcf	$ 9.13	$	$ 9.13
Year Ended December 31, 2004			
Average oil price per Bbl	$38.91	$	$38.91
Average gas prices per Mcf	$ 6.53	$	$ 6.53

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:

	Year ended December 31,		
	2006	2005	2004
Standardized measure, beginning of year	$ 727,062	$ 286,739	$ 309,438
Changes during the year:			
Sales, net of production costs	(340,468)	(213,113)	(203,856)
Net change in prices and production costs	(328,149)	194,965	92,395
Changes in future development costs	(49,357)	(63,621)	(17,474)
Development costs incurred	159,616	67,193	38,373
Accretion of discount	106,333	40,808	43,048
Net change in income taxes	(254,770)	(214,936)	3,770
Purchases of reserves in place	1,245,847	575,320	
Extensions and discoveries	82,730	80,720	55,743
Sales of reserves in place			(3,077)
Net change due to revision in quantity estimates	(6,067)	(12,442)	(32,025)
Changes in production rates (timing) and other	18,166	(14,571)	404
Total	633,881	440,323	(22,699)

Standardized measure, end of year	$ 1,360,943	$ 727,062	$ 286,739

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Note 21 Quarterly Financial Information (Unaudited)

The offshore marine construction industry in the Gulf of Mexico is highly seasonal as a result of weather conditions and the timing of capital expenditures by the 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 2006 and 2005 (in thousands, except per share data):

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
2006				
Net revenues	$291,648	$305,013	$374,424	$395,839
Gross profit	102,266	131,692	130,470	150,980
Net income	56,193	69,944	57,833	163,424
Net income applicable to common shareholders	55,389	69,139	57,029	162,479
Basic earnings per common share	0.71	0.88	0.62	1.80
Diluted earnings per common share	0.67	0.83	0.60	1.73
2005				
Net revenues	$159,575	$166,531	$209,338	$264,028
Gross profit	51,873	52,419	82,928	95,852
Net income	25,961	26,577	43,221	56,810
Net income applicable to common shareholders	25,411	26,027	42,671	56,006
Basic earnings per common share	0.33	0.34	0.55	0.72
Diluted earnings per common share	0.32	0.32	0.53	0.69

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, 2006. Based on this evaluation, the principal executive officer and the principal financial officer have concluded that our disclosure controls and procedures were effective as of the end of the fiscal year ended December 31, 2006 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) recorded, processed, summarized and reported, within the time periods specified in the SEC s rules and forms 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, with exception of the items detailed below 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. On July 1, 2006, we completed the acquisition of Remington Oil and Gas Corporation. We continue to integrate Remington s historical internal controls over financial reporting into our own internal controls over financial reporting including the incorporation of new processes related to exploration activities (rather than just development activities) into our control structure. This ongoing integration may lead to our making additional changes in our internal controls over financial reporting in future fiscal periods.

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 amendment on page 45 and page 47, respectively.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules.***

(1) ***Financial Statements.***

The following financial statements included on pages 44 through 98 in this amendment are for the fiscal year ended December 31, 2006.

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:

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 files 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 on Form 10-K 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).

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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.

10.1 1995 Long Term Incentive Plan, as amended, incorporated by reference to Exhibit 10.3 to the Form S-1.

10.2 Employment Agreement between Owen Kratz and Company dated February 28, 1999, incorporated by reference to Exhibit 10.5 to the registrant s Annual Report on Form 10-K 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).

10.3 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.

10.4 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.

10.5 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.

10.6 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.

10.7 Termination Agreement between James Lewis Connor, III and Company dated August 31, 2006 incorporated by reference to Exhibit 10.1 to the registrant s Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2006, filed by the registrant with the Securities and Exchange Commission on November 7, 2006 (the 2006 Form 10-Q).

10.8 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.

10.9 Employment Letter from the Company to Robert P. Murphy dated December 21, 2006.

10.10 Master Agreement between the Company and Cal Dive International, Inc. dated December 8, 2006.

10.11	Tax agreement between the Company and Cal Dive International, Inc. dated December 14, 2006.
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, Principal Executive Officer.
31.2*	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by A. Wade Pursell, Principal Financial Officer.
32.1**	Section 1350 Certification by Owen Kratz, Principal Executive Officer.
32.2**	Section 1350 Certification by A. Wade Pursell, Principal Financial Officer.

Filed with Original 10-K.

* Filed herewith.

** Furnished herewith.

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SIGNATURES

Pursuant to the requirements of section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

HELIX ENERGY SOLUTIONS GROUP, INC.

By: /s/ A. WADE PURSELL
A. Wade Pursell
Executive Vice President and
Chief Financial Officer

June 18, 2007

INDEX TO EXHIBITS

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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.
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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.

Exhibits

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 on Form 10-K 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.
10.1	1995 Long Term Incentive Plan, as amended, incorporated by reference to Exhibit 10.3 to the Form S-1.
10.2	Employment Agreement between Owen Kratz and Company dated February 28, 1999, incorporated by reference to Exhibit 10.5 to the registrant s Annual Report on Form 10-K 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).
10.3	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.
10.4	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.
10.5	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.

Exhibits

10.6	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.
10.7	Termination Agreement between James Lewis Connor, III and Company dated August 31, 2006 incorporated by reference to Exhibit 10.1 to the registrant s Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2006, filed by the registrant with the Securities and Exchange Commission on November 7, 2006 (the 2006 Form 10-Q).
10.8	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.
10.9	Employment Letter from the Company to Robert P. Murphy dated December 21, 2006.
10.10	Master Agreement between the Company and Cal Dive International, Inc. dated December 8, 2006.
10.11	Tax agreement between the Company and Cal Dive International, Inc. dated December 14, 2006.
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, Principal Executive Officer.
31.2*	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by A. Wade Pursell, Principal Financial Officer.
32.1**	Section 1350 Certification by Owen Kratz, Principal Executive Officer.
32.2**	Section 1350 Certification by A. Wade Pursell, Principal Financial Officer.

Filed with Original 10-K.

* Filed herewith.

** Furnished herewith.