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

Table of Contents

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.

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

Table of Contents

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;

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;

2

- 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

Table of Contents

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 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

Table of Contents

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) .

Table of Contents

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 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.

Table of Contents

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.

Table of Contents

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.

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				

(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.

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.

Table of Contents

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.

Table of Contents

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%	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.

Table of Contents

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.

18

Table of Contents

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%.

Table of Contents

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)

Table of Contents

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.

21

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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 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.

Table of Contents

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

28

Table of Contents

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	Year Ended December 31, 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	Year Ended December 31, 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

Table of Contents

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.

Table of Contents

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

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.*

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.

Table of Contents

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)		