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

FORM 10-K

(Mark One)

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

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2003

[ ] 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 0-22739

CAL DIVE INTERNATIONAL, 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 NORTH SAM HOUSTON PARKWAY EAST SUITE 400 HOUSTON, TEXAS	77060
(Address of Principal Executive Offices)	(Zip Code)

REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE:
(281) 618-0400

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

TITLE OF EACH CLASS	NAME OF EACH EXCHANGE ON WHICH REGISTERED
- None	None

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

COMMON STOCK (NO PAR VALUE)
(Title of Class)

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 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. [X] Yes [ ] No

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). [X] Yes [ ] No

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2003 was $762,022,087 based on the last reported sales price of the Common Stock on June 30, 2003, as reported on the NASDAQ/National Market System.

The number of shares of the registrant's Common Stock outstanding as of March 10, 2004 was 38,024,298.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement for the Annual Meeting of Shareholders to be held on May 11, 2004, are incorporated by reference into Part III hereof.

CAL DIVE INTERNATIONAL, INC. ("CDI") INDEX -- FORM 10-K

FORWARD LOOKING STATEMENTS

This Annual Report on Form 10-K, or Annual Report, including "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7, contains forward-looking statements that involve risks, uncertainties and assumptions that could cause the results of Cal Dive International, Inc. and its consolidated subsidiaries ("CDI" or "Cal Dive") to differ materially from those expressed or implied by such forward-looking statements. All statements, other than statements of historical fact, are statements that could be deemed forward-looking statements, including, without limitation, any projections of revenue, gross margin, expenses, earnings or losses from operations, or other financial items; any statements of the plans, strategies and objectives of management for future operations; any statement concerning developments, performance or industry rankings relating to services; any statements regarding future economic conditions or performance; any statements of expectation or belief; and any statements of assumptions underlying any of the foregoing. The risks, uncertainties and assumptions referred to above include the performance of contracts by suppliers, customers and partners; employee management issues; complexities of global political and economic developments; and other risks that are described herein, including, but not limited to, the items discussed in "Factors Influencing Future Results and Accuracy of Forward-Looking Statements" set forth in Item 1 of this Annual Report, and that are otherwise described from time to time in CDI's reports filed with the Securities and Exchange Commission after this report. CDI assumes no obligation and does not intend to update these forward-looking statements.

PART I

ITEM 1. BUSINESS.

OVERVIEW

We are an energy services company, incorporated in the State of Minnesota, specializing in Marine Contracting (subsea construction and well operations) as well as providing oil and gas companies with alternatives to traditional approaches of equity sharing in offshore properties through our Oil & Gas Production and Production Facilities segments. Operations in the Production Facilities segment should begin in 2004. We operate primarily in the Gulf of Mexico, or Gulf, and, since 2002, in the North Sea and the Asia/ Pacific regions with services that cover the lifecycle of an offshore oil and gas field. We believe we have a longstanding reputation for innovation in our subsea construction techniques, equipment design and methods of partnering with customers. Our diversified fleet of 22 vessels and 25 remotely operated vehicles (or ROVs) and trencher systems perform services that support drilling, well completion, intervention, construction and decommissioning projects involving pipelines, production platforms, risers and subsea production systems. We also have acquired significant interests in oil and gas properties and a Deepwater production facility at the Marco Polo field. Our customers include major and independent oil and gas producers, pipeline transmission companies and offshore engineering and construction firms.

We have positioned ourselves for work in water depths greater than 1,000 feet, referred to as the Deepwater, by continuing to grow our technically advanced fleet of dynamically positioned, or DP, vessels, ROVs and the number of highly experienced support professionals we employ. These DP vessels serve as advanced work platforms for the subsea solutions that we provide with our alliance partners, a group of internationally recognized contractors and manufacturers. Most notably, the Q4000, our Deepwater semi-submersible multi-service vessel, or MSV, incorporates patented technologies that can improve Deepwater well completion, intervention and construction economics for our customers. Availability of the Q4000 and the Seawell, together with our other large vessels, the Eclipse, Mystic Viking and Intrepid, enable us to offer a diverse fleet of DP subsea construction and intervention vessels.

Our ROV subsidiary, Canyon Offshore, Inc., or Canyon, offers survey, engineering, repair, maintenance and international cable burial services in the Gulf, Europe/West Africa and Asia/Pacific regions. Our wholly owned subsidiaries, Wells Ops, Inc., and its Aberdeen, Scotland based sister company, Well Ops (U.K.) Limited, engineer, manage and conduct well construction, intervention and decommissioning operations in water depths from 200 to 10,000 feet in, respectively, the Gulf of Mexico and the North Sea. Well Ops (U.K.) Limited also performs saturation diving in the North Sea from its DP vessel, the Seawell.

On the Outer Continental Shelf, or OCS, of the Gulf of Mexico, in water depths up to 1,000 feet, we perform traditional subsea services, including air and saturation diving and salvage work. Our shallow water diving division provides a full complement of services in the shallow water market from the shore to a depth of 200 feet. We own and operate eleven vessels that are permanently dedicated to performing traditional diving services. Altogether we employ more than 600 full-time supervisors, divers, tenders and support staff who make us the market leader for all manned diving services in the Gulf. In depths from 200 feet to 1,000 feet, these services are provided by our two four-point saturation diving vessels, with another five DP vessels capable of providing such services on the OCS. We provide subsea construction services in the OCS "spot market" where projects are generally turnkey in nature, short in duration (two to thirty days), and require the availability of multiple vessels due to frequent rescheduling. The technical and operational experience of our personnel and the scheduling flexibility offered by our large fleet enable us to manage turnkey projects and to meet our customers' requirements. We have also established a presence in the salvage market by offering customers a number of options to address their decommissioning obligations in a cost-efficient manner, particularly the removal of smaller structures.

In our Oil & Gas Production business, our subsidiary Energy Resource Technology, Inc., or ERT, acquires and produces mature, non-core offshore property interests, offering customers a cost-effective alternative to the decommissioning process required by law. In 2003, ERT continued to successfully pursue its "PUD" strategy of acquiring and developing proved undeveloped, or PUD, reserves, i.e., leases where the exploratory well had encountered proven reserves that were judged by the current owner to be too marginal to justify development. In addition, ERT's reservoir engineering and geophysical expertise enabled us in 2000 to acquire a working interest in Gunnison, a Deepwater Gulf oil and natural gas exploration project, in partnership with the operator, Kerr McGee Oil & Gas Corp., which began initial production in December 2003.

In our Production Facilities segment we participate in the ownership of production facilities in hub locations where there is potential for significant Subsea tieback activity. In addition to production from the Gunnison reservoir, Cal Dive will receive ongoing revenues from its 20% interest in the production facility as satellite prospects are drilled and tied back to the spar. Deepwater Gateway, Inc., our second such endeavor, involves a 50% ownership position in the tension-leg platform installed at Anadarko's Marco Polo field at Green Canyon block 608. At both Gunnison and Marco Polo, we participated in field development planning and performed subsea construction work.

BUSINESS STRENGTHS AND STRATEGIES

Our overall corporate goal is to increase shareholder value by strengthening our market position to provide a return that leads our Peer Group. Our goal for Return on Invested Capital is 10% or greater. We attempt to achieve our return on capital objective by focusing on the following business strengths and strategies.

OUR STRENGTHS

Fleet of DP Vessels. We believe that our fleet of DP construction vessels is the fourth largest in the world, with one of the most diverse and technically advanced collections of subsea intervention and construction capabilities. The comprehensive services provided by our DP vessels are both complementary and overlapping, enabling us to provide customers with the redundancy essential for most projects, especially in the Deepwater.

Formation of Well Operations Subsidiary as a "First In" Advantage. Establishment of the Well Ops group followed the construction of the purpose-built Q4000 and the acquisition of the Subsea Well Operations Business Unit of Technip in Aberdeen, Scotland. The mission of these companies is to provide the industry with a single, comprehensive source for addressing current well operations needs and to engineer for future needs.

Experienced Personnel and Turnkey Contracting. A key element of our successful growth has been our ability to attract and retain experienced personnel who are among the best in the industry at providing turnkey contracting. We believe the recognized skill of our personnel and our successful operating history uniquely position us to capitalize on the trend in the oil and gas industry of increased outsourcing to contractors and suppliers.

Major Provider of Marine Construction Services on the OCS. We believe that our shallow water diving division, and our position in the Gulf for saturation diving services make us one of the largest supplier of subsea construction services on the Gulf of Mexico OCS. We expect the aging infrastructure will require increasing level of IMR.

Oil & Gas Production. The strategy of ERT's oil and gas production business differentiates us from our competitors and helps to offset the cyclical nature of our subsea construction operations. Each of ERT's oil and gas investments is designed to secure utilization of CDI construction vessels. We successfully applied the ERT model to the Deepwater with our involvement in the Gunnison field.

Production Facilities. At the Marco Polo field, our 50% ownership in the production facility will allow us to realize a return on investment consisting of both a fixed monthly demand charge and a volumetric tariff charge. In addition, we will assist with the installation of the TLP and work to develop the surrounding acreage that can be tied back to the platform by our construction vessels. Our long-term goal is that 40% of all of our construction utilization is provided by ownership of offshore fields and production facilities.

Decommissioning Operations. Over the last decade, we have established a presence in decommissioning offshore facilities, particularly in the removal of the smaller structures and caissons that make up approximately half of the structures in the Gulf. We expect demand for decommissioning services to increase due to the significant backlog of platforms and caissons that must be removed in accordance with government regulations.

OUR STRATEGIES

Focusing on the Gulf and Global Expansion. We will continue to focus on the Gulf of Mexico, where we have provided marine construction services since 1975, as well as the North Sea, Southeast Asia and other Deepwater basins worldwide. We expect oil and gas exploration and development activity in the Deepwater Gulf and other Deepwater basins of the world to increase over the next several years.

Capturing a Leading Presence in the Deepwater Market. Our fleet now includes nine world-class DP vessels, six of which are based in the Gulf of Mexico. In addition, through Canyon we own and operate 25 ROV and trencher systems, including a "T750" Super Trencher as well as three Triton XLS ROV systems to fulfill requirements under a Master Service Agreement entered into with Technip-Coflexip. Canyon represents an integration that is consistent with our strategy of controlling key aspects along the critical path of significant Deepwater projects.

Developing Well Operations Niche. As major and independent oil and gas companies expand operations in the Deepwater basins of the world, development of these reserves will often require the installation of subsea trees. Historically, drilling rigs were usually necessary for subsea well operations to troubleshoot or enhance production, shift zones or perform recompletions. Three of our vessels serve as work platforms for well operations services at costs significantly less than drilling rigs. In the Gulf of Mexico, our multi-service semi-submersibles, the Q4000 and the Uncle John have set a series of well operations "firsts" in increasingly deep water without the use of a rig. In the North Sea the Seawell has provided intervention and abandonment services for more than 450 North Sea wells since her commissioning in 1987. Competitive advantages of the CDI vessels stem from their lower operating costs, together with an ability to mobilize quickly and to maximize productive time by performing a broad range of tasks for intervention, construction, inspection, repair and maintenance.

Acquiring Mature Oil and Gas Properties. Through ERT we have been acquiring mature or sunset properties since 1992, thereby providing customers a cost effective alternative to the decommissioning process. In the last eleven years, we have acquired interests in 90 leases and currently are the operator of 46 of 61 active offshore leases. ERT has been able to achieve a significant return on capital by efficiently developing acquired reserves, lowering lease operating expenses, and adding new reserves through exploitation drilling and well work. Our customers consider ERT a preferred buyer as a result of ERT's reputation, Cal Dive's financial strength and salvage expertise. As an industry leader in acquiring mature properties, ERT has a significant flow of potential acquisitions. At December 31, 2003, ERT's total proved reserves were 149.8 Bcfe, including 70.9 Bcfe of proved reserves assigned to our ownership position in Gunnison.

Expanding Ownership in Production Facilities. Along with GulfTerra Energy Partners L.P., Cal Dive owns 50% of the tension leg production platform installed at the Marco Polo field, as well as the 20% interest in the spar at Gunnison. Ownership of these production facilities provide a transmission type return that does not entail any reservoir or commodity price risk. The Company plans to seek additional opportunities to invest in such production facilities.

Expanding the PUD Model. We successfully applied the ERT model to the Deepwater with our involvement in the Gunnison field. The Deepwater Gulf has seen a significant increase in oil and gas exploration, development, and production due, in part, to new technologies that reduce operational costs and risks; the discovery of new, larger oil and gas reservoirs with high production potential; government deepwater incentives; and increasing demand and prices. Along with these larger fields are discoveries where the exploratory well has encountered smaller proven undeveloped reserves that are judged by the current owner to be too marginal to justify development. In 2004, ERT will continue to aggressively pursue its strategy of acquiring PUD reserves and develop these reserves utilizing Cal Dive's assets. Depending upon the water depth, development of these fields may require state of the art equipment such as the Q4000, a more specialized asset such as the Intrepid for pipelay, or a combination of Cal Dive contracting assets.

THE INDUSTRY

The offshore oilfield services industry originated in the early 1950s to assist companies as they began to explore and develop offshore fields. The industry has grown significantly since the early 1970s as the domestic oil and gas industry has increasingly relied upon these fields for new domestic production. Factors that we believe will benefit the industry in the coming years include: (i) increasing world demand for oil and natural gas; (ii) a continued increase in exploration, development, and production in the Deepwater Gulf and other Deepwater basins of the world; and (iii) an increased demand for decommissioning services in compliance with MMS regulations as the OCS offshore oil and gas industry continues to mature.

In response to the oil and gas industry's ongoing migration to the Deepwater, equipment and vessel requirements have changed. Most vessels currently operating in the Deepwater Gulf were designed in the 1970s and 1980s for work in a maximum depth of approximately 1,000 feet. These vessels have been modified to take advantage of new technologies and now operate in depths up to 4,000 feet. We believe there is demand in the Gulf for new generation vessels, such as the Q4000 and Intrepid, that are specifically designed to work in water depths beyond 4,000 feet.

Defined below are certain terms and ideas helpful to understanding the services we perform in support of offshore development:

Bcfe: Billions of cubic feet equivalent, used to describe oil volumes converted to their energy equivalent in natural gas as measured in billions of cubic feet.

Deepwater: Water depths beyond 1,000 feet.

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

Dynamic Positioning (DP): Computer-directed thruster systems that use satellite-based positioning and other positioning technologies to ensure the proper counteraction to wind, current and wave forces enabling the vessel to maintain its position without the use of anchors. Two DP systems (DP-2) are necessary to provide the redundancy required to support safe deployment of divers, while only a single DP system is necessary to support ROV operations.

DP-2: Redundancy allows the vessel to maintain position even with failure of one DP system; required for vessels which support both manned diving and robotics and for those working in close proximity to platforms.

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

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

IMR: Inspection, maintenance and repair activities.

Life of Field Services: Services performed on offshore facilities, trees and pipelines from the beginning to the economic end of the life of an oil field, including installation, inspection, maintenance, repair, contract operations, well intervention, recompletion and abandonment.

MBbl: When describing oil, refers to 1,000 barrels containing 42 gallons each.

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

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

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

Outer Continental Shelf (OCS): For purposes of our industry, areas in the Gulf from the shore to 1,000 feet of water depth.

Peer Group: Defined in this Annual Report as comprising Global Industries, Ltd. (Nasdaq: GLBL), Horizon Offshore, Inc. (Nasdaq: HOFF), McDermott International, Inc. (NYSE: MDR), Oceaneering International, Inc. (NYSE: OII), Stolt Offshore SA (Nasdaq: SOSA), Technip-Coflexip (NYSE: TKP) and Torch Offshore, Inc. (Nasdaq: TORC).

Proved Undeveloped Reserve (PUD): Proved undeveloped oil and gas reserves that are expected to be recovered from a new well on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Remotely Operated Vehicle (ROV): Robotic vehicles used to complement, support and increase the efficiency of diving and subsea operations and for tasks beyond the capability of manned diving operations.

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

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

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

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

Subsea Construction Vessels: Subsea services are typically performed with the use of specialized construction vessels which provide an above-water platform that functions as an operational base for divers and ROVs. Distinguishing characteristics of subsea construction vessels include DP systems, saturation diving capabilities, deck space, deck load, craneage and moonpool launching. Deck space, deck load and craneage are important features of the vessel's ability to transport and fabricate hardware, supplies and equipment necessary to complete subsea projects.

Tension Leg Platform (TLP): A floating Deepwater compliant structure designed for offshore hydrocarbon production.

Trencher or Trencher System: A subsea robotics system capable of providing post lay trenching, inspection and burial (PLIB) and maintenance of submarine cables and flowlines in water depths of 30 to 7,200 feet across a range of seabed and environmental conditions.

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

MARINE CONTRACTING

We and our alliance partners provide a full range of marine contracting services in both the shallow water and Deepwater including:

- Exploration. Pre-installation surveys; rig positioning and installation assistance; drilling inspection; subsea equipment maintenance; well completion; search and recovery operations.

- Development. Installation of production platforms; installation of subsea production systems; pipelay support including connecting pipelines to risers and subsea assemblies; pipeline stabilization, testing and inspection; cable and umbilical lay and connection.

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

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

DEEPWATER CONTRACTING AND WELL OPERATIONS

In 1994, we began to assemble a fleet of DP vessels in order to deliver subsea services in the Deepwater and Ultra-Deepwater. Today, our fleet consists of two semi-submersible DP MSVs, the Q4000 and the Uncle John; a dedicated well operations vessel, the Seawell; an umbilical and rigid pipelay vessel, the Intrepid; three construction DP DSVs, the Witch Queen, the Mystic Viking, and the Eclipse; and two ROV support vessels, the Merlin and the Northern Canyon.

Our subsidiary, Canyon Offshore, Inc., operates ROVs and trenchers that are designed for offshore construction, rather than supporting drilling rig operations. As marine construction support in the Gulf of Mexico and other areas of the world moves to deeper waters, ROV systems will play an increasingly important role. Our vessels add value by supporting deployment of Canyon's ROVs. We have positioned ourselves to provide our customers with vessel availability and schedule flexibility to meet the technological challenges of these Deepwater construction developments in the Gulf and internationally. Our ROVs, including the three new Triton XLS ROV systems delivered in 2003, operate in three regions: the Americas (9), Europe/West Africa (5) and Asia Pacific (6). In addition to the ROVs, Canyon also has five trenchers that operate in the Asia Pacific (2) and the Europe/West Africa (3) regions, including a state of the art "T750" Super Trencher.

We assist customers in solving the operational challenges encountered in Deepwater projects by using methods or technologies we have developed. To enhance our ability to provide both full field development and life of field services, we have alliances with other offshore service and equipment providers. These alliances enable us to offer state-of-the-art products and service while maintaining our low overhead base. These alliances are:

- Fugro-McClelland Marine Geoscience, Inc. -- Geotechnical coring and survey

- Schlumberger Limited -- Deepwater downhole services

Utilization of our Deepwater vessels of 79.6% in 2003 improved from 2002's utilization of 72.3%. Major projects for the Deepwater Contracting group in 2002 and 2003 included:

FIELD	CUSTOMER	DESCRIPTION	DEPTH (FEET)
Brazil	Shell/Pecton	Compressor lift	N/A
Brazil	SBM	Crane installation	N/A
Diana	Exxon	Riser tie-in, spool strade installations	4600
Diana	Exxon	Riser tie-in, spool strade installations	4600
Diana D-3	Exxon	Jumper and flying lead installations	4600
El-309	Forest Oil	Platform salvage/Well abandonment	225
Falcon	El Paso Energy Partners	Manifold installation and jumper metrology, Jumper installation	3450
Gunnison	Kerr-McGee	Driven pile installation	3150
Gunnison	Kerr-McGee	Pipelay and umbilical installation	3150
King Kong	Mariner	Jumper and flying lead installations	3400
Marshall/Madison	Exxon	Jumper and flying lead installations	4960
Mica	Exxon	Manifold, suction pile and tree installations	4500
Nakika	Shell	Jumper installation	6900
Nansen/Boomvang	Kerr-McGee	Plet, flexible riser, umbilicals flying lead and jumper installations	3700
Navajo	Kerr-McGee	Installed flex riser, 6-inch pipeline and umbilicals	3700
Princess	Shell	Jumper installation	3700
Princess	Shell	Steel Catenary Riser Installation	3700
Trinidad	BP/Kapok	Umbilical Installation	200

The mission of the Well Ops Group (Well Ops Inc. and Well Ops (U.K.)

Limited) is to provide the industry with a single, comprehensive source for addressing current subsea well operations needs and to engineer for future needs. Our purpose-built vessels serve as work platforms for subsea well operations services at costs significantly less than drilling rigs. In the Gulf of Mexico, the Q4000 and the Uncle John have set a series of "firsts" in increasingly deep water without the use of a rig including: first "live subsea well" intervention; first through tubing subsea well decommission; first "live subsea well" intervention using wireline lubricator; first Deepwater full field decommission; first re-entry and decommission through horizontal tree; first removal and recovery of subsea well templates and horizontal trees; first use of test tree in open water as a lower riser package (LRP); first subsea transfer of tree from one well to another during decommissioning operations; first use of coil tubing drilling in subsea decommissioning; first installation of a "storm choke" as replacement for subsurface safety control valve; all of which utilized a semi-submersible DP MSV instead of a drilling rig; first to provide and apply a purpose-built 7 3/8" bore Intervention Riser System; and the first interventions in 3,900 feet of salt water without use of a rig. The Seawell has provided intervention and abandonment services on more than 450 North Sea wells since her commissioning in 1987. One additional advantage is that the Seawell can undertake saturation diving and construction tasks independently or simultaneously with the well intervention activities. We believe that the Seawell sets the standard for the industry in subsea well intervention and continues to redefine the boundaries of the industry having performed the first U.K. subsea light intervention using a 7 1/16" subsea lubricator. Competitive advantages of our vessels stem from their lower operating costs and the ability to mobilize quickly for multi-well campaigns of work and maximize productive time by performing a broad range of tasks for intervention, construction, inspection, repair and maintenance. Well Ops Inc. and Well Ops (U.K.) Limited also collaborate with leading downhole service providers to provide superior, comprehensive solutions to the well operations challenges faced by our customers. An alliance is currently in place with Schlumberger to provide these services.

SHELF CONTRACTING

On the OCS, in water depths up to 1,000 feet, we perform traditional subsea services including air and saturation diving in support of marine construction activities. Eleven of our vessels are permanently dedicated to performing traditional diving services, with another five DP vessels capable of providing such services, on the OCS. Seven of these vessels support saturation diving. In addition, our highly qualified personnel have the technical and operational experience to manage turnkey projects to satisfy customers' requirements and achieve our targeted profitability.

We deliver our services in the shallow water market, from the shore to a depth of 200 feet, through our shallow water diving division. In addition, our saturation diving vessels can deliver services in depths up to 1,000 feet.

Since 1989, we have undertaken a wide variety of decommissioning assignments, mostly on a turnkey basis. We have established a leading position in the removal of smaller structures, such as caissons and well protectors, which represent approximately half of the structures in the Gulf.

OIL & GAS PRODUCTION

We formed ERT in 1992 to exploit a market opportunity to provide a more efficient solution to offshore abandonment, to expand our off-season salvage and decommissioning activity, and to support full field production development projects. Through ERT we offer customers the option of selling mature offshore fields as an alternative to contracting and managing the many phases of the decommissioning process. The benefits of our strategy are fourfold. First, oil and gas revenues counteract the volatility in revenues we experience in offshore construction. Second, in periods of excess capacity, such as in 2002 and 2003, we have the flexibility to be less dependent on the competitive bid market and instead focus on negotiated contracts. Third, our oil and gas operations generate significant cash flow that has partially funded construction and/or modification of assets such as the Q4000, Intrepid and Eclipse, enabling us to add technical talent to support our expansion into the new Deepwater frontier. Finally, a major objective of our investments in oil and gas properties is to secure the associated marine construction work.

Within ERT we have assembled a team of personnel with experience in geology, geophysics, reservoir engineering, drilling, production engineering, facilities management, lease operations and petroleum land management. ERT generates income in three ways: lowering salvage costs by using our assets, operating the field more cost effectively, and extending reservoir life through well exploitation operations. When a company sells an OCS property, they retain the financial responsibility for plugging and decommissioning if their purchaser becomes financially unable to do so. Thus, it becomes important that a property be sold to a purchaser who has the financial wherewithal to perform their contractual obligations. Although there is significant competition in this mature field market, ERT's reputation, supported by Cal Dive's financial strength, have made it the purchaser of choice of many major and independent oil and gas companies. In addition, ERT's reservoir engineering and geophysical expertise enabled us in 2000 to acquire a working interest in Gunnison, a Deepwater Gulf oil and natural gas exploration project, in partnership with the operator, Kerr-McGee Oil & Gas Corp., which began initial production in December 2003.

The Deepwater Gulf has seen a significant increase in oil and gas exploration, development, and production due, in part, to new technologies that reduce operational costs and risks; the discovery of new, larger oil and gas reservoirs with high production potential; government deepwater incentives; and increasing demand and prices. Along with these larger fields are discoveries where the exploratory well has encountered smaller proven undeveloped reserves that are judged by the current owner to be too marginal to justify development. In 2004, ERT will continue to aggressively pursue its strategy of acquiring PUD reserves, and develop these reserves utilizing Cal Dive's assets. Depending upon the water depth, development of these fields may require state of the art equipment such as the Q4000, a more specialized asset such as the Intrepid for pipelay, or a combination of Cal Dive contracting assets.

The table below sets forth information, as of December 31, 2003, with respect to estimates of net proved reserves and the present value of estimated future net cash flows at such date, prepared in accordance with guidelines established by the Securities and Exchange Commission. The Company's estimates of reserves at December 31, 2003, have been audited by Huddleston & Co., Inc., independent petroleum engineers. All of the Company's reserves are located in the United States. 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.

	TOTAL PROVED

Estimated Proved Reserves:	
Natural gas (MMcf)...	74,660
Oil and condensate (MBbls).................................	12,521
Standardized measure of discounted future net cash flows (pre-tax)*..	$430,482,246

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* The standardized measure of discounted future net cash flows attributable to our reserves was prepared using constant prices as of the calculation date, discounted at 10% per annum. As of December 31, 2003, we owned an interest in 288 gross (256 net) oil wells and 151 gross (91 net) natural gas wells located in federal offshore waters in the Gulf of Mexico.

PRODUCTION FACILITIES

There are over 100 discoveries in the Deepwater Gulf that have yet to be brought into production. Many of these are smaller reservoirs that standing alone cannot justify the economics of a host production facility. As a result, we expect that the Deepwater Gulf will be developed in a hub and satellite field concept that resembles the approach the airline industry has used with regional hub locations. We expect significant opportunities as this occurs. At the Marco Polo field, our 50% ownership in the production facility will allow us to realize a return on investment consisting of both a fixed monthly demand charge and a volumetric tariff charge. In addition, we will assist with the installation of the TLP and work to develop the surrounding acreage that can be tied back to the platform by our construction vessels. Through our 20% interest in the Gunnison field, we also own an interest in the spar production facility.

CUSTOMERS

Our customers include major and independent oil and gas producers, pipeline transmission companies and offshore engineering and construction firms. The level of construction services required by any particular customer depends on the size of that customer's capital expenditure budget devoted to construction plans in a particular year. Consequently, customers that account for a significant portion of contract revenues in one fiscal year may represent an immaterial portion of contract revenues in subsequent fiscal years. The percent of consolidated revenue of major customers was as follows: 2003 -- Shell Trading (US) Company (10%) and Petrocom Energy Group Ltd. (10%); 2002 -- Horizon Offshore, Inc. (10%) and BP Trinidad & Tobago LLC (11%); 2001 -- Horizon Offshore, Inc. (18%) and Enron Corp. (10%). Shell Trading, Petrocom and Enron were purchasers of ERT's oil and gas production. Marine contracting revenues from Horizon Offshore, Inc. were 5%, 10% and 18% of consolidated revenues during the years ended December 31, 2003, 2002 and 2001, respectively. We estimate that in 2003 we provided subsea services to over 200 customers. Our projects are typically of short duration and are generally awarded shortly before mobilization. Accordingly, we believe backlog is not a meaningful indicator of future business results.

COMPETITION

The marine contracting industry is highly competitive. While price is a factor, the ability to acquire specialized vessels, attract and retain skilled personnel, and demonstrate a good safety record are also important. Our competitors on the OCS include Global Industries Ltd., Oceaneering International, Inc., Stolt Offshore S.A., Torch Offshore, Inc., and a number of smaller companies, some of which only operate a single vessel and often compete solely on price. For Deepwater projects, our principal competitors include Stolt Offshore S.A., Subsea 7, Technip-Coflexip and Torch.

ERT encounters significant competition for the acquisition of mature oil and gas properties. Our ability to acquire additional properties depends upon our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. Competition includes TETRA Technologies, Inc. and Superior Energy Services, Inc. Many potential purchasers of oil and gas properties are well-established companies with substantially larger operating staffs and greater capital resources.

TRAINING, SAFETY AND QUALITY ASSURANCE

We have established a corporate culture in which safety is expected to be among the highest priorities. Our corporate goal, based on the belief that all accidents are preventable, is to provide an injury-free workplace by focusing on correct safety behavior. Our safety procedures and training programs were developed by management personnel who came into the industry as divers and who know first hand the physical challenges of the ocean work site. As a result, management believes that our safety programs are among the best in the industry. We have introduced a company-wide effort to enhance a behavioral safety process and training program that makes safety a constant focus of awareness through open communication with all offshore and yard employees. The process includes the documentation of all daily observations and the collection of this data. In addition, we initiated regular monthly visits by project managers to conduct "Hazard Hunts" on each vessel, providing a "safety audit" with a fresh perspective. Results from this program were evident as our safety performance improved significantly in 2002 and 2003.

GOVERNMENT REGULATION

Many aspects of the offshore marine construction industry are subject to extensive governmental regulations. We are subject to the jurisdiction of the Coast Guard, the Environmental Protection Agency, the MMS and the U.S. Customs Service, as well as private industry organizations such as the American Bureau of Shipping. In the North Sea, regulations govern working hours and a specified working environment, as well as standards for diving procedures, equipment and diver health. These North Sea standards are some of the most stringent worldwide. In the absence of any specific regulation, our North Sea branch adheres to standards set by the International Marine Contractors Association and the International Maritime Organisation.

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

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

The MMS requires lessees of OCS properties to post bonds or provide other adequate financial assurance in connection with the plugging and abandonment of wells located offshore and the removal of all production facilities. Operators on the OCS are currently required to post an area-wide bond of $3.0 million, or

$500,000 per producing lease. We have provided adequate financial assurance for our offshore leases as required by the MMS.

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

Under OCSLA and the Federal Oil and Gas Royalty Management Act, MMS also administers oil and gas leases and establishes regulations that set the basis for royalties on oil and gas produced from the leases. The MMS amends these regulations from time to time. For example, on March 15, 2000, the MMS issued a final rule governing the calculation of royalties and the valuation of crude oil produced from federal leases (the "2000 Oil Rule"). The rule modified the valuation procedures for both arm's length and non-arm's length crude oil transactions to decrease reliance on oil posted prices and assign a value to crude oil that better reflects market value. The rule has been challenged in the United States District Court for the District of Columbia by two industry trade associations, but that litigation is currently inactive, although a motion for its reactivation has been filed by the state of California. As a result of the litigation and MMS's experience with enforcing the 2000 Oil Rule, on August 20, 2003, MMS published a proposed rule which would amend provisions in the 2000 Oil Rule regarding the valuation of non-arm's-length sales and the calculation of transportation allowances. MMS is expected to finalize the rule early in calendar year 2004.

Further, in 1997, the MMS issued a final rule amending its regulations regarding costs for natural gas transportation that are deductible for royalty valuation purposes when natural gas is sold off-lease. Among other matters, for purposes of computing royalties owed, the rule disallows as deductions certain costs, such as aggregator/marketer fees and transportation imbalance charges and associated penalties. A United States District Court enjoined substantial portions of this rule on March 28, 2000. The United States appealed the district court decision. On February 8, 2002, the Court of Appeals for the District of Columbia reversed the District Court in part and reinstated the greater portion of the rule. The United States Supreme Court denied the trade associations' petition for review on January 13, 2003. An MMS proposal to formally repeal the portion of the rule that remains enjoined following the Court of Appeals' decision and to address other matters is expected by mid-2004.

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978, or NGPA, and the regulations promulgated thereunder by the Federal Energy Regulatory Commission, or FERC. In the past, the federal government has regulated the prices at which oil and gas could be sold. While sales by producers of natural gas, and all sales of crude oil, condensate and natural gas liquids currently can be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead sales in the natural gas industry began with the enactment of the NGPA. In 1989, the Natural Gas Wellhead Decontrol Act was enacted. This act amended the NGPA to remove both price and non-price controls from natural gas sold in "first sales" no later than January 1, 1993.

Sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation remain subject to extensive federal and state regulation. Several major regulatory changes have been implemented by Congress and the FERC from 1985 to the present that affect the economics of natural gas production, transportation and sales. In addition, the FERC continues to promulgate revisions to various aspects of the rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC jurisdiction. These initiatives may also affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. The ultimate impact of the complex rules and regulations issued by the FERC since 1985 cannot be predicted.

We cannot predict what further action the FERC will take on these matters, but we do not believe any such action will materially affect us differently than other companies with which we compete.

Additional proposals and proceedings before various federal and state regulatory agencies and the courts could affect the oil and gas industry. We cannot predict when or whether any such proposals may become effective. In the past, the natural gas industry has been heavily regulated. There is no assurance that the regulatory approach currently pursued by the FERC will continue indefinitely. Notwithstanding the foregoing, we do not anticipate that compliance with existing federal, state and local laws, rules and regulations will have a material effect upon our capital expenditures, earnings or competitive position.

ENVIRONMENTAL REGULATION

Our operations are subject to a variety of national (including federal, state and local) and international laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often complex and costly to comply with and that carry substantial administrative, civil and possibly criminal penalties for failure to comply. Under these laws and regulations, we may be liable for remediation or removal costs, damages and other costs associated with releases of hazardous materials including oil into the environment, and such liability may be imposed on us even if the acts that resulted in the releases were in compliance with all applicable laws at the time such acts were performed. Some of the environmental laws and regulations that are applicable to our business operations are discussed in the following paragraphs, but the discussion does not cover all environmental laws and regulations that govern our operations.

The Oil Pollution Act of 1990, as amended, or OPA, imposes a variety of requirements on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in waters of the United States. A "Responsible Party" includes the owner or operator of an onshore facility, a vessel or a pipeline, and the lessee or permittee of the area in which an offshore facility is located. OPA imposes liability on each Responsible Party for oil spill removal costs and for other public and private damages from oil spills. Failure to comply with OPA may result in the assessment of civil and criminal penalties. OPA establishes liability limits of $350 million for onshore facilities, all removal costs plus $75 million for offshore facilities and the greater of $500,000 or $600 per gross ton for vessels other than tank vessels. The liability limits are not applicable, however, if the spill is caused by gross negligence or willful misconduct; if the spill results from violation of a federal safety, construction, or operating regulation; or if a party fails to report a spill or fails to cooperate fully in the cleanup. Few defenses exist to the liability imposed under OPA. Management is currently unaware of any oil spills for which we have been designated as a Responsible Party under OPA that will have a material adverse impact on us or our operations.

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

OPA also requires owners and operators of vessels over 300 gross tons to provide the Coast Guard with evidence of financial responsibility to cover the cost of cleaning up oil spills from such vessels. We currently own and operate six vessels over 300 gross tons. Satisfactory evidence of financial responsibility has been provided to the Coast Guard for all of our vessels.

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

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

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

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

Management believes that we are in compliance in all material respects with all applicable environmental laws and regulations to which we are subject. We do not anticipate that compliance with existing environmental laws and regulations will have a material effect upon our capital expenditures, earnings or competitive position. However, changes in the environmental laws and regulations, or claims for damages to persons, property, natural resources or the environment, could result in substantial costs and liabilities, and thus there can be no assurance that we will not incur significant environmental compliance costs in the future.

EMPLOYEES

We rely on the high quality of our workforce. As of December 31, 2003, we had 1,114 employees, 258 of which were salaried. As of that date, we also utilized approximately 500 non-U.S. citizens to crew our foreign flag vessels under a crewing contract with C-MAR Services (UK), Ltd. of Aberdeen, Scotland. None of our employees belong to a union or are employed pursuant to any collective bargaining agreement or any similar arrangement. We believe that our relationship with our employees and foreign crew members is good.

WEBSITE AND OTHER AVAILABLE INFORMATION

The Company maintains a website on the Internet with the address of www.caldive.com. Copies of this Annual Report on Form 10-K for the year ended December 31, 2003, and copies of the Company's Quarterly Reports on Form 10-Q for 2003 and 2004 and any Current Reports on Form 8-K for 2003 and 2004, and any amendments thereto, are or will be available free of charge at such website as soon as reasonably practicable after they are filed with, or furnished to, the SEC. Information contained on the Company's website is not part of this report.

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

FACTORS INFLUENCING FUTURE RESULTS AND ACCURACY OF FORWARD-LOOKING STATEMENTS

Shareholders should carefully consider the following risk factors in addition to the other information contained herein. This Annual Report on Form 10-K includes certain statements that may be deemed "forward-looking statements" within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. You can identify these statements by forward-looking words such as "anticipate," "believe," "budget," "could," "estimate," "expect," "forecast," "intend," "may," "plan," "potential," "should," "will" and "would' or similar words. You should read statements that contain these words carefully because they discuss our future expectations, contain projections of our future financial position or results of operations or state other forward-looking information. We believe that it is important to communicate our future expectations to our investors. However, there may be events in the future that we are not able to predict or control accurately. The factors listed below in this section, captioned "Factors Influencing Future Results and Accuracy of Forward-Looking Statements," as well as any cautionary language in this Annual Report, provide examples of risks, uncertainties and events that may cause our actual results to differ materially from the expectations we describe in our forward-looking statements. 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.

OUR BUSINESS IS ADVERSELY AFFECTED BY LOW OIL AND GAS PRICES AND BY THE CYCLICALITY OF THE OIL AND GAS INDUSTRY.

Our business is 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,
- Economic and political conditions in the Middle East and other oil-producing regions,
- Coordination by the Organization of Petroleum Exporting Countries, or OPEC,
- The cost of exploring for and producing oil and gas,
- 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,
- Interest rates and the cost of capital,
- Environmental regulations, and
- Tax policies.

The level of offshore construction activity did not increase despite higher commodity prices in 2003. We cannot assure you that activity levels will increase anytime soon. 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 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. As construction activity expands into deeper water in the Gulf, 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 is less than replacement value. In the event of property loss due to a catastrophic marine disaster, mechanical failure or collision, insurance may not cover a substantial loss of revenues, increased costs and other liabilities, and could have a material adverse effect on our operating performance if we were to lose any of our large vessels.

OUR CONTRACTING BUSINESS 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, but not all, 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 CONSEQUENCES.

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

ESTIMATES OF OUR OIL AND GAS RESERVES, FUTURE CASH FLOWS AND ABANDONMENT COSTS MAY BE SIGNIFICANTLY INCORRECT.

Our proved reserves at December 31, 2003, included the reserves assigned to our ownership position in the Gunnison project, a Deepwater Gulf of Mexico oil and gas field operated by Kerr-McGee Oil & Gas Corp. These reserves constitute nearly 50% of our total proved reserves as of December 31, 2003. 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 year ended December 31, 2003, 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 substantially 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 earnings.

EXPECTED CASH FLOWS FROM THE Q4000, INTREPID AND SEAWELL, AS WELL AS CANYON, MAY NOT BE IMMEDIATE OR AS HIGH AS EXPECTED.

The Q4000, Intrepid and the Seawell are vessels that were placed into service during 2002. In addition, during 2002 we acquired Canyon Offshore, Inc., a supplier of ROVs to the offshore construction and telecommunications industry. While we believe demand and market rates should improve, we will not receive any material increase in revenue or cash flow from their operation until there is significant improvements in demand and market rates. We cannot assure you that customer demand for these vessels and Canyon's services will be as high as currently anticipated and, as a result, our future cash flows may be adversely affected. New vessels from third parties may also enter the market in the coming years and compete with the Q4000, Intrepid and the Seawell for contracts.

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, 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.

WE MAY NOT BE ABLE TO COMPETE SUCCESSFULLY AGAINST CURRENT AND FUTURE COMPETITORS.

The business in which we operate is 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.

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 subsea 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 or issuable 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 Cal Dive 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 all 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.

ITEM 2. PROPERTIES

OUR VESSELS

We own a fleet of 21 vessels and 25 ROVs and trenchers. We also lease one vessel. We believe that the Gulf market requires specially designed and/or equipped vessels to competitively deliver subsea construction services. Nine of our vessels have DP capabilities specifically designed to respond to the Deepwater market requirements. Eight of our vessels (six of which are based in the Gulf) have the capability to provide saturation diving services. Recent developments in our fleet include:

Q4000: We began construction of our newest Ultra-Deepwater MSV, the Q4000 in 1999, and accepted her delivery in early 2002. The vessel cost approximately $170 million and incorporates our latest semi-submersible technologies, including various patented elements such as the absence of lower hull cross bracing. A variable deck load of over 4,000 metric tons and upgraded well completions capability make the vessel particularly well suited for large offshore construction projects in the Ultra-Deepwater. Its Huisman-Itrec multi-purpose tower has an open face which allows free access from three sides, an advantage for a construction and intervention vessel.

Intrepid: The Intrepid offers customers a pipelay/construction vessel capable of carrying an 8,000 metric ton deck load. She began work in June of 2002.

Eclipse: This large DP DSV is 370 feet long, 67 feet wide, and includes a saturation diving system and DP-2. The Eclipse began work in March 2002.

Seawell: This purpose-build 364 foot mono-hull DP vessel, capable of supporting both manned diving and ROVs, was recently upgraded for coiled tubing deployment and well testing. The Seawell was purchased in July 2002.

ROVs: Canyon currently operates 20 ROVs and five trencher systems. In 2003, Canyon took delivery of three new Triton XLS ROV systems and a state of the art "T750" Super Trencher.

LISTING OF VESSELS, BARGE AND ROVS

DATE MOONPOOL FOUR CAL
DIVE CLEAR DECK DECK
LAUNCH/ POINT PLACED IN
LENGTH SPACE (SQ. LOAD SAT
ANCHOR CRANE CAPACITY
SERVICE (FEET) FEET)
(TONS) BERTHS DIVING
MOORED (TONS) --------- --
---- --------- ------ ---
--- -------- ------ ------
-------- DP MSVS: Uncle
John.................
11/96 254 11,834 460 102 X
-- 2(LOGO)100 FLOWLINE
LAY:
Intrepid...................
8/97 381 17,728 4,000 50 -
- -- 400 WELL OPERATIONS:
Seawell....................
7/02 368 9,688 700 129 X -
- 130
Q4000......................
4/02 312 26,400 4,000 135
X -- 160 and 360 Derrick -
- 600 DP DSVS:
Eclipse...................
3/02 367 8,611 2,436 109 X
-- Forward -- 5 Mid -- 4.3
Aft -- 92/43 A-Frame 20.4
T Witch
Queen................
11/95 278 5,600 500 60 X -
- 50 Mystic
Viking.............. 6/01
253 5,600 1,340 60 X -- 50
DP ROV SUPPORT Vessels:
Merlin.....................
12/97 198 2,900 268 32 --
-- A-Frame Crane -- 5
Northern
Canyon(2)......... 6/02
276 9,677 2,400 58 -- --
50 DSVS: Cal Diver
I................ 7/84 196
2,400 220 40 X X 30 Cal
Diver II..............
6/85 166 2,816 300 32 X X
A-Frame Cal Diver
V................ 9/91 168
2,324 490 34 -- X A-Frame
Cal Diver
IV............... 3/01 120
1,440 60 24 -- -- -- Mr.
Fred...................
3/00 167 2,465 500 36 -- X
25 Mr.
Sonny..................
3/01 175 3,480 409 28 -- X
35 UTILITY VESSELS: Mr.
Jim....................
2/98 110 1,210 64 19 -- --
-- Mr.
Jack...................
1/98 120 1,220 66 22 -- --
-- Polo
Pony..................
3/01 110 1,240 69 25 -- --
-- Sterling
Pony.............. 3/01
110 1,240 64 25 -- -- --
White
Pony................. 3/01
116 1,230 64 25 -- -- --
OTHER: Cal Dive Barge
I........... 8/90 150 N/A
200 30 -- X 200
Talisman...................

11/00 195 3,000 675 14 --
-- -- 25 ROVs and
Trenchers(3)... Various --
-- -- -- -- -- --
CLASSIFICATION(1) --------
--------- DP MSVS: Uncle
John................. DNV
FLOWLINE LAY:
Intrepid...................
ABS WELL OPERATIONS:
Seawell....................
DNV
Q4000......................
ABS DP DSVS:
Eclipse....................
DNV Witch
Queen................ DNV
Mystic
Viking.............. DNV
DP ROV SUPPORT Vessels:
Merlin.....................
ABS Northern
Canyon(2)......... DNV
DSVS: Cal Diver
I................ ABS Cal
Diver II...............
ABS Cal Diver
V................ ABS Cal
Diver IV...............
ABS Mr.
Fred...................
USCG Mr.
Sonny..................
ABS UTILITY VESSELS: Mr.
Jim....................
USCG Mr.
Jack...................
USCG Polo
Pony..................
USCG Sterling
Pony.............. USCG
White
Pony................. USCG
OTHER: Cal Dive Barge
I........... ABS
Talisman...................
ABS 25 ROVs and
Trenchers(3)... --

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(1) Under government regulations and our insurance policies, we are required to maintain our vessels in accordance with standards of seaworthiness and safety set by government regulations and classification organizations. We maintain our fleet to the standards for seaworthiness, safety and health set by the American Bureau of Shipping, or ABS, Det Norske Veritas, or DNV, and the U.S. Coast Guard, or USCG. The ABS is one of several classification societies used by ship owners to certify that their vessels meet certain structural, mechanical and safety equipment standards, including Lloyd's Register, Bureau Veritas and DNV among others.

(2) Leased.

(3) Average age of ROV fleet is approximately 3.25 years.

We incur routine drydock inspection, maintenance and repair costs pursuant to Coast Guard regulations and in order to maintain ABS or DNV classification for our vessels. In addition to complying with these requirements, we have our own vessel maintenance program that we believe permits us to continue to provide our customers with well maintained, reliable vessels. In the normal course of business, we charter other vessels on a short-term basis, such as tugboats, cargo barges, utility boats and dive support vessels. Most of our vessels are subject to ship mortgages to secure our $70.0 million revolving credit facility, except the Northern Canyon (leased) and the Q4000 (subject to liens to secure the MARAD financing guarantees).

SUMMARY OF NATURAL GAS AND OIL RESERVE DATA

The table below sets forth information, as of December 31, 2003, with respect to estimates of net proved reserves and the present value of estimated future net cash flows at such date, prepared in accordance with guidelines established by the Securities and Exchange Commission. The Company's estimates of reserves at December 31, 2003, have been audited by Huddleston & Co., Inc., independent petroleum engineers. All of the Company's reserves are located in the United States. 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.

	TOTAL PROVED
Estimated Proved Reserves:	
Natural gas (MMcf)	74,660
Oil and condensate (MBbls)	12,521
Standardized measure of discounted future net cash flows (pre-tax)*	$430,482,246

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* The standardized measure of discounted future net cash flows attributable to our reserves was prepared using constant prices as of the calculation date, discounted at 10% per annum. As of December 31, 2003, we owned an interest in 288 gross (256 net) oil wells and 151 gross (91 net) natural gas wells located in federal and state offshore waters in the Gulf of Mexico.

PRODUCTION FACILITIES

At Gunnison, we own a 20% interest in the Gunnison truss spar facility, together with the operator Kerr-McGee Oil & Gas Corp. who owns a 50% interest, and Nexen, Inc., who 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 MMCF of gas. This facility is designed with excess capacity to accommodate production from satellite prospects in the area.

Through our interest Deepwater Gateway, L.L.C., a 50/50 venture between the Company and GulfTerra Energy Partners, L.P., the Company owns a 50% interest in the Marco Polo Tension Leg Platform (TLP) which was installed on Green Canyon Block 608 in 4,300 feet of water. Deepwater Gateway was formed to construct, install, and own the Marco Polo TLP in order to process production from Anadarko Petroleum Corporation's Marco Polo field discovery at Green Canyon Block 608. Anadarko required 50,000 barrels of oil per day and 150 million feet per day of processing capacity for Marco Polo. The Marco Polo TLP was designed to process 120,000 barrels of oil per day and 300 million cubic feet per day and payload and space for up to six Subsea tie backs.

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 Morgan City, Louisiana. All of our facilities are leased.

PROPERTIES AND FACILITIES SUMMARY

FUNCTION SIZE -------- ---- Houston,
Texas....................... Cal
Dive International, Inc. (CDI)
43,500 square feet Corporate
Headquarters, Project Management,
and Sales Office; Energy Resource
Technology, Inc.; and Well Ops Inc.
Canyon Offshore, Inc. (Canyon)
15,000 square feet Corporate
Headquarters, Management and Sales
Office Aberdeen,
Scotland................... Canyon
Sales Office 12,000 square feet Well
Ops (U.K.) Limited Operations 4,600
square feet
Singapore...........................
Canyon Operations 10,000 square feet
Morgan City,
Louisiana............... CDI
Operations 28.5 acres CDI Warehouse
30,000 square feet CDI Offices 4,500
square feet Lafayette,
Louisiana................. CDI
Operations 8 acres CDI Warehouse
12,000 square feet CDI Offices 5,500
square feet New Orleans,
Louisiana............... CDI Sales
Office 2,724 square feet

ITEM 3. LEGAL PROCEEDINGS

INSURANCE AND LITIGATION

Our operations are subject to the inherent risks of offshore marine activity, including accidents resulting in personal injury and the loss of life or property, environmental mishaps, mechanical failures, fires and collisions. We insure against these risks at levels consistent with industry standards. We also carry workers' compensation, maritime employer's liability, general liability and other insurance customary in our business. All insurance is carried at levels of coverage and deductibles that we consider financially prudent. Our services are provided in hazardous environments where accidents involving catastrophic damage or loss of life could occur, and litigation arising from such an event may result in our being named a defendant in lawsuits asserting large claims. To date, we have been involved in only one such claim, where the cost of our vessel, the Balmoral Sea, was fully covered by insurance. Although there can be no assurance that the amount of insurance we carry is sufficient to protect us fully in all events, or that such insurance will continue to be available at current levels of cost or coverage, we believe that our insurance protection is adequate for our business operations. A successful liability claim for which we are underinsured or uninsured could have a material adverse effect on our business.

We are involved in various legal proceedings, primarily involving claims for personal injury under the General Maritime Laws of the United States and the Jones Act as a result of alleged negligence. In addition, we from time to time incur other claims, such as contract disputes, in the normal course of business. In that regard, in 1998, one of our subsidiaries entered into a subcontract with Seacore Marine Contractors Limited ("Seacore") to provide a vessel to a Coflexip subsidiary in Canada ("Coflexip"). Due to difficulties with respect to the sea states and soil conditions the contract was terminated and an arbitration to recover damages was commenced. A preliminary liability finding has been made by the arbitrator against Seacore and in favor of the Coflexip subsidiary. We were not a party to this arbitration proceeding. Seacore and Coflexip settled this matter prior to the conclusion of the arbitration proceeding with Seacore paying Coflexip $6.95 million CDN. Seacore has initiated an arbitration proceeding against Cal Dive Offshore Ltd. ("CDO"), a subsidiary of Cal Dive, seeking contribution of one-half of this amount. Because only one of the grounds in the preliminary findings by the arbitrator is applicable to CDO, and because CDO holds substantial counterclaims against Seacore, it is anticipated that our subsidiary's exposure, if any, should be less than $500,000.

During 2002, we engaged in a large construction project and in late September of that year, supports engineered by a subcontractor failed resulting in over a month of downtime for two of CDI's vessels. Management believes that under the terms of the contract, we are entitled to indemnification for the contractual stand-by rate for the vessels during their downtime (the indemnification claim). The customer has disputed these invoices along with certain other change orders. Of the amounts billed by us for this project, $9.6 million had not been collected as of December 31, 2003. We have initiated arbitration proceedings, in accordance with the terms of the contract, to resolve this dispute.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

None.

ITEM 5. EXECUTIVE OFFICERS OF THE COMPANY

The executive officers of Cal Dive are as follows:

NAME	AGE	POSITION
Owen Kratz................................	49	Chairman and Chief Executive Officer and Director
Martin R. Ferron.........................	47	President and Chief Operating Officer and Director
S. James Nelson, Jr......................	62	Vice Chairman and Director
James Lewis Connor, III..................	46	Senior Vice President, General Counsel and Corporate Secretary
A. Wade Pursell..........................	39	Senior Vice President, Chief Financial Officer and Treasurer
Lloyd A. Hajdik..........................	38	Vice President -- Corporate Controller and Chief Accounting Officer

Owen Kratz is Chairman and Chief Executive Officer of Cal Dive International, Inc. He was appointed Chairman in May 1998 and has served as our Chief Executive Officer since April 1997. Mr. Kratz served as President from 1993 until February 1999, and as a Director since 1990. He served as Chief Operating Officer from 1990 through 1997. Mr. Kratz joined Cal Dive in 1984 and has held various offshore positions, including saturation diving supervisor, and has had management responsibility for client relations, marketing and estimating. From 1982 to 1983, Mr. Kratz was the owner of an independent marine construction company operating in the Bay of Campeche. Prior to 1982, he was a superintendent for Santa Fe and various international diving companies, and a saturation diver in the North Sea.

Martin R. Ferron has served on our Board of Directors since September 1998. Mr. Ferron became President in February 1999 and has served as Chief Operating Officer since January 1998. Mr. Ferron has 24 years of experience in the oilfield industry, including seven in senior management positions with the international operations of McDermott and Oceaneering. Mr. Ferron has a civil engineering degree, a master's degree in marine technology, an MBA and is a chartered civil engineer.

S. James Nelson, Jr. is Vice Chairman and has been a Director of Cal Dive since 1990. Prior to October 2000, he was Executive Vice President and Chief Financial Officer. From 1985 to 1988, Mr. Nelson was the Senior Vice President and Chief Financial Officer of Diversified Energies, Inc., the former parent of Cal Dive, at which time he had corporate responsibility for Cal Dive. From 1980 to 1985, Mr. Nelson served as Chief Financial Officer of Apache Corporation, an oil and gas exploration and production company. From 1966 to 1980, Mr. Nelson was employed with Arthur Andersen & Co., and, from 1976 to 1980, he was a partner serving on the firm's worldwide oil and gas industry team. Mr. Nelson received an undergraduate degree (BS) from Holy Cross College and an MBA from Harvard University; he is also a Certified Public Accountant.

James Lewis Connor, III became Senior Vice President and General Counsel of Cal Dive in May 2002 and Corporate Secretary in July 2002. He had previously served as Deputy General Counsel since May 2000. Mr. Connor has been involved with the oil and gas industry for nearly 20 years, including 11 years in his capacity as legal counsel to both companies and individuals. Prior to joining Cal Dive, Mr. Connor was a Senior Counsel at El Paso Production Company (formerly Sonat Exploration Company) from 1997 to 2000 and previously from 1995 to 1997 was a senior associate in the oil, gas and energy law section of Hutcheson & Grundy, L.L.P. Mr. Connor received his Bachelor of Science degree from Texas A&M University in 1979 and his law degree, with honors, from the University of Houston in 1991.

A. Wade Pursell is Senior Vice President and Chief Financial Officer of Cal Dive International, Inc. In this capacity, which he was appointed to in October 2000, Mr. Pursell oversees the finance, treasury, accounting, tax, administration and corporate planning functions. He joined Cal Dive in May 1997, as Vice President -- Finance and Chief Accounting Officer. From 1988 through 1997 he was with Arthur Andersen LLP, lastly as an Experienced Manager specializing in the offshore services industry (which included servicing the Cal Dive account from 1990 to 1997). Mr. Pursell received an undergraduate degree (BS) from the University of Central Arkansas and is a Certified Public Accountant.

Lloyd A. Hajdik joined the Company in December 2003 as Vice President -- Corporate Controller. From January 2002 to November 2003 he was Assistant Corporate Controller for Houston-based NL Industries, Inc. Prior to NL, Mr. Hajdik served as Senior Manager of SEC Reporting and Accounting Services for Compaq Computer Corporation from 2000 to 2002, and as Controller for Halliburton's Baroid Drilling Fluids and Zonal Isolation product service lines from 1997 to 2000. Mr. Hajdik served as Controller for Engineering Services for Cliffs Drilling Company from 1995 to 1997 and was with Ernst & Young in the audit practice from 1989 to 1995. Mr. Hajdik graduated from Southwest Texas State University receiving a Bachelor of Business Administration degree. Mr. Hajdik is a Certified Public Accountant and a member of the Texas Society of CPAs as well as the American Institute of Certified Public Accountants.

ITEM 6. THE MANAGERS OF THE SUBSIDIARIES OF THE COMPANY

The Managers of the Subsidiaries of Cal Dive are as follows:

NAME	AGE	POSITION
John Edwards.............................	47	Co-President and COO -- Canyon Offshore, Inc.
Johnny Edwards...........................	50	President -- Energy Resource Technology, Inc.
William F. Morrice.......................	39	General Manager -- Well Ops (U.K.) Limited
Martin O'Carroll.........................	45	Co-President and CFO -- Canyon Offshore, Inc.
Ian Collie...............................	52	General Manager -- Well Ops. Inc.

John Edwards became Co-President and Chief Operating Officer of Canyon Offshore Inc. in January 2002 upon its merger with Cal Dive International, Inc. Mr. Edwards co-founded Canyon in 1996 and initially served as Co-Chief Executive Officer and Chief Operating Officer. Mr. Edwards has been involved in the subsea industry for twenty-one years, with primary roles in commercial and marketing. He was with Sonsub International from 1988 to 1996, beginning as Regional Manager of South East Asia operations, and taking on later roles as International Marketing Manager and Senior Vice President Commercial. Previously he was with Oceonics PLC from 1982 to 1988.

Johnny Edwards has been President of ERT since March 2000. He joined ERT in 1994 as Engineering and Acquisitions Manager, where he has been instrumental in the growth of the company. Prior to joining ERT, Mr. Edwards worked for ARCO Oil & Gas Company for 19 years and held various technical and management positions in engineering and operations. Mr. Edwards received a Bachelor of Science degree in Chemical Engineering from Louisiana Tech University in 1975.

William F. Morrice became General Manager of Well Ops (U.K.) Limited, a wholly owned subsidiary of Cal Dive International Inc., since the company was formed in July 2002 and acquired the well intervention vessel MSV Seawell and the Well Operations Business Unit of Technip-Coflexip. Mr. Morrice had previously been with Technip-Coflexip for 13 years, having joined them as a Project Engineer in 1990. Mr. Morrice assumed responsibility for the Well Operations Business Unit that operates from the Seawell in 1995. Mr. Morrice graduated from Robert Gordon's University in 1996 with a Bachelor of Science degree and Postgraduate Diploma in Offshore Engineering. Further postgraduate studies attained a Postgraduate Certificate in Project Management from Aberdeen University.

Martin O'Carroll became Co-President and Chief Financial Officer of Canyon Offshore Inc. in January 2002 upon its merger with Cal Dive International, Inc. Mr. O'Carroll co-founded Canyon in 1996 and initially served as Co-Chief Executive Officer and Chief Financial Officer. Mr. O'Carroll has been involved in the subsea industry for fifteen years, with primary roles in finance and administration. He was with Sonsub International from 1988 to 1996, serving as Chief Financial Officer and later Senior Vice President of Finance and Administration. Previously he was Manager of Price Waterhouse in Ireland and Australia from 1980 to 1988. Mr. O'Carroll received his Bachelor of Commerce degree in 1980 from the National University of Ireland, and is an Associate of the Institute of Chartered Accountants in Ireland and Australia.

Ian Collie became General Manager of Well Ops Inc. a subsidiary of Cal Dive International, Inc. of Houston in 2002, and had previously served as Well Intervention Manager since 1999. Mr. Collie has been involved with the oil and gas industry for 32 years which includes 28 years of offshore experience to different companies. Prior to joining Cal Dive, Mr. Collie was a Well Operations Superintendent at Coflexip Stena Offshore Ltd. (U.K. and U.S.A.) from 1990 to 1999.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED SHAREHOLDER MATTERS

Our common stock is traded on the Nasdaq National Market under the symbol "CDIS." The following table sets forth, for the periods indicated, the high and low closing sale prices per share of our common stock:

COMMON STOCK PRICE	HIGH	LOW
Calendar Year 2002		
First quarter	$25.20	$20.50
Second quarter	$27.22	$21.70
Third quarter	$21.90	$15.36
Fourth quarter	$25.20	$20.00
Calendar Year 2003		
First quarter	$24.46	$16.99
Second quarter	$23.19	$15.95
Third quarter	$22.74	$19.31
Fourth quarter	$25.24	$19.88
Calendar Year 2004		
First quarter (through March 10, 2004)	$27.49	$22.74

On March 10, 2004, the closing sale price of our common stock on the Nasdaq National Market was $25.70 per share. As of March 10, 2004, there were an estimated 4,170 beneficial holders of our common stock.

We have never declared or paid cash dividends on our common stock and do not intend to pay cash dividends in the foreseeable future. We currently intend to retain earnings, if any, for the future operation and growth of our business. In addition, our financing arrangements prohibit the payment of cash dividends on our common stock. See "Management's Discussion and Analysis of Financial Condition and Results of Operations -- Liquidity and Capital Resources."

ITEM 6. SELECTED FINANCIAL DATA

The financial data presented below for each of the five years ended December 31, 2003, should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations and the Consolidated Financial Statements and Notes to Consolidated Financial Statements included elsewhere in this Form 10-K (in thousands, except per share amounts).

	2003	2002	2001	2000	1999
Net Revenues	$396,269	$302,705	$227,141	$181,014	$160,054
Gross Profit	92,083	53,792	66,911	55,369	37,251
Net Income Before Change in Accounting Principle	33,678	12,377	28,932	23,326	16,899
Cumulative Effect of Change in Accounting Principle, net	530	--	--	--	--
Net Income	34,208	12,377	28,932	23,326	16,899
Preferred Stock Dividends and Accretion	1,437	--	--	--	--
Net Income Applicable to Common Shareholders	32,771	12,377	28,932	23,326	16,899
Net Income per common share					
Basic: Net Income Before Change in Accounting Principle	0.86	0.35	0.89	0.74	0.56
Cumulative Effect of Change in Accounting Principle	0.01	--	--	--	--
Net Income Applicable to Common Shareholders	0.87	0.35	0.89	0.74	0.56
Diluted: Net Income Before Change in Accounting Principle	0.86	0.35	0.88	0.72	0.55
Cumulative Effect of Change in Accounting Principle	0.01	--	--	--	--
Net Income Applicable to Common Shareholders	0.87	0.35	0.88	0.72	0.55
Total Assets	882,842	840,010	494,296	347,488	243,722
Long-Term Debt	206,632	223,576	98,048	40,054	--
Shareholders' Equity	381,141	337,517	226,349	194,725	150,872

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

BUSINESS OVERVIEW

Oil and gas prices, the offshore mobile rig count, and Deepwater construction activity are three of the primary indicators we use to forecast the future performance of our Marine Contracting business. Our construction services generally follow successful drilling activities by six to eighteen months on the OCS and twelve months or longer in the Deepwater arena. The level of drilling activity is related to both short- and long-term trends in oil and gas prices. While oil and natural gas prices have been at robust levels for the last two years, offshore drilling activity has yet to respond. Our primary leading indicator, the number of offshore mobile rigs contracted, is currently at approximately 115 rigs employed in the Gulf of Mexico, flat with year ago levels and compared to 182 during the first quarter of 2001. The Deepwater Gulf is principally being developed for oil, with the complexity of developing these reservoirs resulting in significant lead times to first production.

Our business is 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,

- Economic and political conditions in the Middle East and other oil-producing regions,

- Coordination by the Organization of Petroleum Exporting Countries, or OPEC,

- The cost of exploring for and producing oil and gas,

- 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,

- Interest rates and the cost of capital,

- Environmental regulations, and

- Tax policies.

The level of offshore construction activity did not increase despite higher commodity prices in 2003. We cannot assure you that activity levels will increase anytime soon. 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 and results of operations.

Product prices impact our oil and gas operations in several respects. We seek to acquire producing oil and gas properties that are generally in the later stages of their economic life. The sellers' potential abandonment liabilities are a significant consideration with respect to the offshore properties we have purchased to date. Although higher natural gas prices tend to reduce the number of mature properties available for sale, these higher prices typically contribute to improved operating results for ERT. In contrast, lower natural gas prices typically contribute to lower operating results for ERT and a general increase in the number of mature properties available for sale. We expanded the scope of our gas and oil operations by taking a working interest in Gunnison, a Deepwater Gulf development of Kerr-McGee Oil & Gas Corp., and participating in the ownership of the Marco Polo production facility.

Our proved reserves at December 31, 2003, included the reserves assigned to our ownership position in Gunnison. These reserves constitute nearly 50% of our total proved reserves as of December 31, 2003. This Annual Report contains estimates of our proved oil and gas reserves based upon reports audited by our independent petroleum engineers. 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 substantially from those estimated in these reports. Any significant variance in these assumptions could materially affect the estimated quantity and value of our proved reserves.

Regarding marine contracting, vessel utilization is historically lower during the first quarter due to winter weather conditions in the Gulf and the North Sea. Accordingly, we plan our drydock inspections and other routine and preventive maintenance programs during this period. During the first quarter, a substantial number of our customers finalize capital budgets and solicit bids for construction projects. The bid and award process during the first two quarters typically leads to the commencement of construction activities during the second and third quarters. As a result, we have historically generated up to 65% of our marine contracting revenues in the last six months of the year. Our operations can also be severely impacted by weather during the fourth quarter. Operation of oil and gas properties and production facilities tends to offset the impact of weather since the first and fourth quarters are typically periods of high demand and strong prices for natural gas. Due to this seasonality, full year results are not likely to be a direct multiple of any particular quarter or combination of quarters.

The following table sets forth for the periods presented average U.S. natural gas prices, our equivalent natural gas production, the average number of offshore rigs under contract in the Gulf, the number of platforms installed and removed in the Gulf and the vessel utilization rates for each of the major categories of our fleet.

	2003				2002				2001			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
U.S. natural gas prices(1).............	$ 6.25	$ 5.61	$ 4.87	$ 5.06	$ 2.54	$ 3.36	$ 3.20	$ 4.29	$ 6.44	$ 4.38	$ 2.76	$ 2.39
ERT oil and gas production (MMcfe).....	6,780	6,722	7,175	7,241	2,910	3,487	3,967	6,230	4,290	3,552	3,289	2,797
Rigs under contract in the Gulf(2)............	119	126	128	122	122	125	131	128	182	189	165	125
Platform installations(3).......	7	21	12	13	14	19	14	11	12	19	20	11
Platform removals(3).....	3	11	34	18	11	37	26	4	13	11	19	16
Our average vessel utilization rate:(4)												
DP.....................	80%	82%	78%	79%	74%	81%	71%	81%	61%	76%	85%	95%
Saturation DSV.........	75	78	85	79	45	68	75	89	72	67	82	91
Surface diving.........	51	44	54	34	58	62	47	66	61	81	72	60
Derrick barge..........	--	30	87	45	--	46	52	38	30	54	67	47

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(1) Henry Hub Gas Daily Average (the midpoint index price per Mmbtu for deliveries into a specific pipeline for the applicable calendar day as reported by Platts Gas Daily in the "Daily Price Survey" table).

(2) Average monthly number of rigs contracted, as reported by Offshore Data Services.

(3) Source: Minerals Management Service (2003) and Offshore Data Services (2002 and 2001); installation and removal of platforms with two or more piles in the Gulf.

(4) Average vessel utilization rate is calculated by dividing the total number of days the vessels in this category generated revenues by the total number of days in each quarter.

CRITICAL ACCOUNTING POLICIES

Our results of operations and financial condition, as reflected in the accompanying financial statements and related footnotes, are subject to management's evaluation and interpretation of business conditions, changing capital market conditions and other factors which could affect the ongoing viability of our business segments and/or our customers. We believe the most critical accounting policies in this regard are the recognition of revenue and the associated estimation of revenue allowance on gross amounts billed, evaluation of recoverability of property and equipment and goodwill balances and the accounting for decommissioning liabilities for ERT. While these issues require us to make judgments that are somewhat subjective, they are generally based on a significant amount of historical data and current market data.

ERT acquisitions of producing offshore properties are recorded at the fair value exchanged at closing together with an estimate of its proportionate share of the decommissioning liability assumed in the purchase based upon its working interest ownership percentage. In estimating the decommissioning liability assumed in offshore property acquisitions, we perform detailed estimating procedures, including engineering studies and then reflect the liability at fair value on a discounted basis as discussed below. We follow the successful efforts method of accounting for our interests in oil and gas properties. Under the successful efforts method, the costs of successful wells and leases containing productive reserves are capitalized. Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized.

The Company also considers the following accounting policies to be the most critical to the preparation of its financial statements:

GOODWILL

The Company tests for the impairment of goodwill on at least an annual basis. The Company's goodwill impairment test involves a comparison of the fair value of each of the Company's reporting units. with its carrying amount. The fair value is determined using discounted cash flows and other market-related valuation models, such as earnings multiples and comparable asset market values. These tests are influenced significantly by management estimates of future cash flows and the related expected utilization of assets. Prior to the adoption of Statement of Financial Accounting Standards ("SFAS") No. 142, Goodwill and Indefinite-Lived Intangibles ("SFAS No. 142"), goodwill was amortized on a straight line basis over 25 years. In conjunction with the adoption of this statement, the Company has discontinued the amortization of goodwill.

PROPERTY AND EQUIPMENT

Property and equipment, both owned and under capital leases, are recorded at cost. Depreciation is provided primarily on the straight-line method over the estimated useful lives of the assets described in footnote 2 to the Consolidated Financial Statements included herein.

For long-lived assets to be held and used, excluding goodwill, the Company bases its evaluation on impairment indicators such as the nature of the assets, the future economic benefit of the assets, any historical or future profitability measurements and other external market conditions or factors that may be present. If such impairment indicators are present or other factors exist that indicate that the carrying amount of the asset may not be recoverable, the Company determines whether an impairment has occurred through the use of an undiscounted cash flows analysis of the asset at the lowest level for which identifiable cash flows exist. If an impairment has occurred, the Company recognizes a loss for the difference between the carrying amount and the fair value of the asset. The fair value of the asset is measured using quoted market prices or, in the absence of quoted market prices, is based on management's estimate of discounted cash flows. Assets are classified as held for sale when the Company has a plan for disposal of certain assets and those assets meet the held for sale criteria.

The Company evaluates the impairment of its oil and gas properties on a field-by-field basis whenever events or changes in circumstances indicate, but at least annually, an asset's carrying amount may not be recoverable. Unamortized capital costs are reduced to fair value if the expected undiscounted future cash flows are less than the asset's net book value. Cash flows are determined based upon proved reserves using prices and costs consistent with those used for internal decision making. Although prices used are likely to approximate market, they do not necessarily represent current market prices. Given that spot market prices are subject to volatile changes, it is the Company's opinion that a long-term view of market prices will lead to a more appropriate valuation of long-term assets.

ACCOUNTING FOR DECOMMISSIONING LIABILITIES

SFAS No. 143, Accounting for Asset Retirement Obligations, addresses the financial accounting and reporting obligations and retirement costs related to the retirement of tangible long-lived assets. Among other things, SFAS No. 143 requires oil and gas companies to reflect decommissioning liabilities on the face of the balance sheet at fair value on a discounted basis. ERT historically has purchased producing offshore oil and gas properties that are in the later stages of production. In conjunction with acquiring these properties, ERT assumes an obligation associated with decommissioning the property in accordance with the regulations set by government agencies. The abandonment liability related to the acquisitions of these properties is determined through a series of management estimates.

Prior to an acquisition and as part of evaluating the economics of an acquisition, ERT will estimate the plug and abandonment liability. ERT personnel prepare detailed cost estimates to plug and abandon wells and remove necessary equipment in accordance with regulatory guidelines. ERT currently calculates the discounted value of the abandonment liability (based on the estimated year the abandonment will occur) in accordance with SFAS No. 143 and capitalizes that portion as part of the basis acquired and records the related abandonment liability at fair value.

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

The adoption of SFAS No. 143 resulted in a cumulative effect adjustment as of January 1, 2003 to record (i) a $33.1 million decrease in the carrying values of proved properties, (ii) a $7.4 million decrease in accumulated depreciation, depletion and amortization of property and equipment, (iii) a $26.5 million decrease in decommissioning liabilities and (iv) a $0.3 million increase in deferred income tax liabilities. The net impact of items (i) through (iv) was to record a gain of $0.5 million, net of tax, as a cumulative effect adjustment of a change in accounting principle in the Company's consolidated statements of operations upon adoption on January 1, 2003. The Company has no material assets that are legally restricted for purposes of settling its decommissioning liabilities.

ACCOUNTING FOR REDEEMABLE STOCK IN SUBSIDIARY

SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity, requires that certain financial instruments, which under previous guidance were accounted for as equity, must now be accounted for as liabilities. The financial instruments affected include mandatorily redeemable stock, certain financial instruments that require or may require the issuer to buy back some of its shares in exchange for cash or other assets and certain obligations that can be settled with shares of stock. SFAS No. 150 was effective for all financial instruments entered into or modified after May 31, 2003. As a result of this adoption, the Company reclassified the $4.9 million of Redeemable Stock in Subsidiary from mezzanine classification (i.e., between liabilities and shareholders' equity on the balance sheet) to debt. Otherwise, the adoption had no impact on the Company's consolidated financial statements.

REVENUE RECOGNITION

The Company earns the majority of marine contracting revenues during the summer and fall months. Revenues are derived from billings under contracts (which are typically of short duration) that provide for either lump-sum turnkey charges or specific time, material and equipment charges which are billed in accordance with the terms of such contracts. The Company recognizes revenue as it is earned at estimated collectible amounts. Revenues generated from specific time, materials and equipment charges contracts are generally earned over a dayrate basis and recognized as amounts are earned in accordance with contract terms. Revenues generated in the pre-operation mode before a contract commences are deferred and recognized in accordance with contract terms. Direct and incremental costs associated with pre-operation activities are similarly deferred and recognized over the estimated contract period.

Revenue on significant turnkey contracts is recognized on the percentage-of-completion method based on the ratio of costs incurred to total estimated costs at completion, or achievement of certain contractual milestones if provided for in the contract. Contract price and cost estimates are reviewed periodically as work progresses and adjustments are reflected in the period in which such estimates are revised. Provisions for estimated losses on such contracts are made in the period such losses are determined. Unbilled revenue represents revenue attributable to work completed prior to year-end which has not yet been invoiced. All amounts included in unbilled revenue at December 31, 2003 are expected to be billed and collected within one year.

The Company records revenues from the sales of crude oil and natural gas when delivery to the customer has occurred and title has transferred. This occurs when production has been delivered to a pipeline or a barge lifting has occurred. The Company may have an interest with other producers in certain properties. In this case the Company uses the entitlements method to account for sales of production. Under the entitlements method the Company may receive more or less than its entitled share of production. If the Company receives more than its entitled share of production, the imbalance is treated as a liability. If the Company receives less than its entitled share, the imbalance is recorded as an asset.

REVENUE ALLOWANCE ON GROSS AMOUNTS BILLED

The Company bills for work performed in accordance with the terms of the applicable contract. The gross amount of revenue billed will include not only the billing for the original amount quoted for a project but also include billings for services provided which the Company believes are allowed under the terms of the related contract but are outside the scope of the original quote. The Company establishes a revenue allowance for these additional billings based on its collections history if conditions warrant such a reserve.

FOREIGN CURRENCY

The functional currency for the Company's foreign subsidiary, Well Ops (U.K.) Limited, is the applicable local currency (British Pound). Results of operations for this subsidiary are translated into U.S. dollars using average exchange rates during the period. Assets and liabilities of this foreign subsidiary are translated into U.S. dollars using the exchange rate in effect at the balance sheet date and the resulting translation adjustment, which was a gain of $5.0 million, net of taxes, and $2.5 million, net of taxes, in 2003 and 2002, respectively, is included as accumulated other comprehensive income, as a component of shareholders' equity. All foreign currency transaction gains and losses are recognized currently in the statements of operations.

Canyon Offshore, the Company's ROV subsidiary, has operations in the United Kingdom and Southeast Asia sectors. Canyon conducts the majority of its affairs in these regions in U.S. dollars which it considers the functional currency. When currencies other than the U.S. dollar are to be paid or received the resulting gain or loss from translation is recognized in the statements of operations. These amounts for the years ended December 31, 2003 and 2002, respectively, were not material to the Company's results of operations or cash flows.

ACCOUNTING FOR PRICE RISK MANAGEMENT ACTIVITIES

The Company's price risk management activities involve the use of derivative financial instruments to hedge the impact of market price risk exposures primarily related to our oil and gas production. All derivatives are reflected in our balance sheet at their fair market value.

There are two types of hedging activities: hedges of cash flow exposure and hedges of fair value exposure. The Company engages primarily in cash flow hedges. Hedges of cash flow exposure are entered into to hedge a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability. Changes in the derivative fair values that are designated as cash flow hedges are deferred to the extent that they are effective and are recorded as a component of accumulated other comprehensive income until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings in oil and gas production revenues.

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

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

During 2003 and 2002 the Company entered into various cash flow hedging swap and costless collar contracts to fix cash flows relating to a portion of the Company's oil and gas production. All of these qualified for hedge accounting and none extended beyond a year and a half. The aggregate fair market value of the swaps and collars was a liability of $2.2 million and $4.1 million as of December 31, 2003 and 2002, respectively. For the years ended December 31, 2003 and 2002, the Company recorded a net of tax $1.2 million gain, and $2.6 million loss, respectively, in other comprehensive income (loss) within shareholders' equity as these hedges were highly effective. The balance in the fair value hedge adjustments account is recognized in earnings when the hedged item is sold.

INCOME TAXES

Deferred income taxes are based on the difference between financial reporting and tax bases of assets and liabilities. The Company utilizes the liability method of computing deferred income taxes. The liability method is based on the amount of current and future taxes payable using tax rates and laws in effect at the balance sheet date. Income taxes have been provided based upon the tax laws and rates in the countries in which operations are conducted and income is earned. A valuation allowance for deferred tax assets is recorded when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. See footnote 9 to the Consolidated Financial Statements included herein for discussion of net operating loss carry forwards and deferred income taxes.

WORKER'S COMPENSATION CLAIMS

Our onshore employees are covered by Worker's Compensation. Offshore employees, including divers and tenders and marine crews, are covered by Maritime Employers Liability insurance policy which covers Jones Act exposures. The Company incurs worker's compensation claims in the normal course of business, which management believes are covered by insurance. The Company, its insurers and legal counsel analyze each claim for potential exposure and estimate the ultimate liability of each claim.

ACCOUNTING PRINCIPLES NOT YET ADOPTED

In January 2003, FASB Interpretation ("FIN") No. 46, Consolidation of Variable Interest Entities, was issued which requires companies that control another entity through interests other than voting interests to consolidate the controlled entity. FIN No. 46 applies immediately to variable interest entities created after January 31, 2003, and applies in the first interim period beginning after March 15, 2004 to variable interest entities created before February 1, 2003. The related disclosure requirements are effective immediately. The Company currently believes that it has no involvement with any variable interest entity covered by the scope of FIN No. 46.

OTHER MATTERS

The FASB's Emerging Issues Task Force ("EITF") currently is deliberating on EITF No. 03-O, Whether Mineral Rights Are Tangible or Intangible Assets, and EITF No. 03-S, Application of FASB Statement No. 142, Goodwill and Other Intangible Assets, to Oil and Gas Companies. These proposed statements will determine whether contract-based oil and gas mineral rights are classified as tangible or intangible assets based on the EITF's interpretation of SFAS No. 141, Business Combinations, and SFAS No. 142. Historically, the Company has classified all of its contract-based mineral rights within property, plant and equipment and has generally not identified these amounts separately. If the EITF determines that these mineral rights should be presented as intangible assets, the Company would have to reclassify its contract-based oil and gas mineral rights acquired after June 30, 2001 to intangible assets and make additional disclosures in accordance with SFAS No. 142. If The Company adopted this change, approximately $51 million and $87 million of the property, plant and equipment balance (net of accumulated depreciation, depletion and amortization) related to proved properties would be reclassified to intangible assets at December 31, 2003 and 2002, respectively. The Company has been amortizing these amounts under the unit-of-production method and would continue to amortize the mineral rights under this method. Based on its understanding of the scope of the EITF deliberations, the Company believes the adoption of this potential decision would have no material effect on its results of operations.

RESULTS OF OPERATIONS

We derive our revenues, earnings and cash flows from two primary business segments: Marine Contracting and Oil and Gas Production. Within Marine Contracting, we operate primarily in the Gulf of Mexico (Gulf), and recently in the North Sea and Asia/Pacific, with services that cover the lifecycle of an offshore oil or gas field. Our current diversified fleet of 22 vessels and 25 remotely operated vehicles (ROVs) and trencher systems perform services that support drilling, well completion, intervention, construction and decommissioning projects involving pipelines, production platforms, risers and subsea production systems. We also have a significant investment in offshore oil and gas production as well as production facilities. Operations in the Production Facilities segment should begin in 2004 as Marco Polo comes online. Our customers include major and independent oil and gas producers, pipeline transmission companies and offshore engineering and construction firms.

COMPARISON OF YEARS ENDED 2003 AND 2002

Revenues. During the year ended December 31, 2003, revenues increased $93.6 million, or 31%, to $396.3 million compared to $302.7 million for the year ended December 31, 2002. The Marine Contracting segment contributed $19.1 million of the increase, primarily as a result of the acquisition of the Seawell during the third quarter of 2002. In addition, the Q4000, Intrepid and Eclipse worked a full year in 2003 as compared to nine months in the prior year, as these vessels were placed in service in the second quarter of 2002.

Oil and Gas Production revenue for the year ended December 31, 2003 increased $74.5 million, or 119%, to $137.3 million from $62.8 million during the prior year. The increase was due to a 33% increase in our average realized commodity prices to $4.82 per Mcfe, net of hedges in place ($4.98 per Mcfe of natural gas and $27.63 per barrel of oil) in 2003 from $3.63 per Mcfe ($3.49 per Mcfe of natural gas and $24.73 per barrel of oil) in 2002. Production increased 69% to 28 Bcfe during 2003 from 16.6 Bcfe during the prior year as a result of the property acquisitions during the third quarter of 2002 and Gunnison coming on line in December 2003.

Gross Profit. Gross profit of $92.1 million for 2003 was $38.3 million, or 71%, greater than the $53.8 million gross profit recorded in the prior year due entirely to the revenue increase in Oil and Gas Production mentioned above. Oil and Gas Production gross profit increased $39.4 million from $26.7 million in 2002 to $66.1 million for 2003, due to the increases in average realized commodity prices and production described above.

Gross margins improved to 23% for the year ended December 31, 2003 compared to 18% during 2002 due primarily to the aforementioned increases in average realized commodity prices. Marine Contracting margins decreased from 11% for 2002 to 10% during 2003 due mainly to the depressed markets for offshore construction in the GOM and the North Sea, increased competition in the OCS market and increased offshore insurance costs offset by the impact of charges recorded in the fourth quarter of 2002 related to a contract dispute.

Selling & Administrative Expenses. Selling and administrative expenses were $35.9 million in 2003, which is 10% more than the $32.8 million incurred in 2002, primarily due to the addition of business units acquired and higher ERT incentive accruals. Selling and administrative expenses were 9% of revenues for 2003, which was two points better than the 11% for 2002 due primarily to the EEX settlement charges in the fourth quarter of 2002.

Other (Income) Expense. The Company reported other expense of $3.5 million for the year ended December 31, 2003 in contrast to $2.0 million for 2002. Included in other expense for 2002 is a $1.1 million gain on our foreign currency derivative associated with the acquisition of Well Ops (U.K.) Limited recorded in other income in June 2002. Net interest expense of $2.4 million for 2003 is higher than the $2.2 million in the prior year as a result of our higher debt levels and the reduction of capitalized interest expense as the Q4000 and Intrepid were in service for only the last nine month's of 2002.

Income Taxes. Income taxes increased to $19.0 million for 2003, compared to $6.7 million in the prior year period due to increased profitability. The effective rate increased to 36% in 2003 compared to 35% in 2002 due primarily to provisions for foreign taxes. The Internal Revenue Service ("IRS") is in the process of examining our income tax return for years 2001 and 2002, and the 2001 pre-acquisition income tax return for Canyon Offshore Inc. We believe the ultimate resolution of these audits will not have a material adverse effect on our financial condition, liquidity or results of operations.

Net Income. Net income of $32.8 million for 2003 was $20.4 million, or 165%, greater than 2002, as a result of the factors described above.

COMPARISON OF YEARS ENDED 2002 AND 2001

Revenues. During the year ended December 31, 2002, the Company's revenues increased $75.6 million, or 33%, to $302.7 million compared to $227.1 million for the year ended December 31, 2001 with the Marine Contracting segment contributing all of the increase. Marine Contracting revenues increased to $239.9 million for the year ended December 31, 2002 as compared to $163.7 million in the prior year. Our acquisitions of Canyon Offshore and Well Ops (U.K.) Ltd. added $37.5 million and $21.4 million, respectively. The remainder of the increase was due to the addition of three deepwater construction vessels: the Q4000, the Intrepid and the Eclipse.

Oil and Gas Production revenue for the year ended December 31, 2002 decreased less than 1% to $62.8 million from $63.4 million during the prior year. An increase in production, lead by the significant Shell and Hess acquisitions made late in the third quarter of 2002, was offset by lower average realized commodity prices. Oil and Gas Production increased 19% to 16.6 Bcfe in 2002 from 13.9 Bcfe during 2001, while our average realized commodity price declined 15% to $3.71 per Mcfe ($3.39 per Mcf of natural gas and $25.54 per barrel of oil) in 2002 as compared to $4.37 per Mcfe ($4.44 per Mcf of natural gas and $24.54 per barrel of oil) in the prior year. Oil and condensate represented 38% of ERT revenue in 2002 compared to 30% in 2001.

Gross Profit. Gross profit of $53.8 million for the year ended December 31, 2002 was $13.1 million, or 20%, below the $66.9 million gross profit recorded in the prior year with both segments contributing to the decline. Marine Contracting gross profit decreased $9.6 million, or 26%, to $27.0 million during the year ended December 31, 2002 compared to $36.7 million during 2001. Our DP vessels generated $8.6 million of gross profit, only 43% of the $20.1 million generated in the prior year, due in part to the charges recorded in the fourth quarter related to a contract dispute. Margins for this segment decreased to 11% for the year ended December 31, 2002 compared to 22% in 2001. While our shallow water diving division margins held strong at 30% due to a large amount of shelf repair work following Hurricane Lili, the DP fleet only contributed 7% margins in 2002 compared to 25% in the prior year.

Oil and Gas Production gross profit decreased $3.5 million from $30.2 million in the year ended December 31, 2001 to $26.7 million for the year ended December 31, 2002 due mainly to the aforementioned decrease in average realized commodity prices. Margins declined to 43% during 2002 from 48% during 2001 due to platform repairs and the time necessary for pipelines to return to full production following Hurricane Lili.

Selling and Administrative Expenses. Selling and administrative expenses of $32.8 million in 2002 were $11.5 million, or 54%, higher than the $21.3 million incurred during 2001. The increase is primarily due to the acquisitions of Canyon and Well Ops (U.K.) Ltd. and a charge taken for the settlement of litigation in the fourth quarter of 2002.

Other (Income) Expense. The Company reported net interest expense and other of $2.0 million for the year ended December 31, 2002 in contrast to $1.3 million for the prior year. This increase is due to the increase in debt from our capital program, which resulted in an additional $2.2 million in interest expense, offset by a $1.1 million gain on our foreign currency hedge related to the Well Ops (U.K.) Ltd. acquisition included in other income in the third quarter of 2002.

Income Taxes. Income taxes decreased to $6.7 million for the year ended December 31, 2002, compared to $15.5 million in the prior year due to decreased profitability. Federal income taxes were provided at the statutory rate of 35% in 2002. However, our deduction of Q4000 construction costs as Research and Development expenditures for federal tax purposes resulted in CDI paying no federal income taxes in 2002 and 2001. Since the deduction of Q4000 construction costs affects financial and taxable income in different years, the entire 2002 and 2001 provisions for federal taxes were reflected as deferred income taxes.

Net Income. Net income of $12.4 million for the year ended December 31, 2002 was $16.6 million, or 57%, less than the $28.9 million earned in 2001 as a result of factors described above.

ITEM 7. LIQUIDITY AND CAPITAL RESOURCES

LIQUIDITY AND CAPITAL RESOURCES

In August 2000, we closed the long-term MARAD financing for construction of the Q4000. This U.S. Government guaranteed financing is pursuant to Title XI of the Merchant Marine Act of 1936 which is administered by the Maritime Administration. We refer to this debt as MARAD Debt. In January 2002, the Maritime Administration agreed to expand the facility to $160 million to include the modifications to the vessel which had been approved during 2001. We drew $143.5 million on this facility. In January 2002, we acquired Canyon Offshore, Inc.; in July 2002, we acquired the Well Operations Business Unit of Technip-Coflexip and, in August 2002, ERT made two significant property acquisitions (see further discussion below). These acquisitions significantly increased our debt to total book capitalization ratio from 31% at December 31, 2001 to 40% at December 31, 2002. In order to reduce this leverage, on January 8, 2003, CDI completed the private placement of $25 million of a newly designated class of cumulative convertible preferred stock (Series A-1 Cumulative Convertible Preferred Stock, par value $0.01 per share) which is convertible into 833,334 shares of Cal Dive common stock at $30 per share. As of December 31, 2003 our debt to total book capitalization declined to 35% and working capital increased to $29.8 million from $14.3 million at December 31, 2002.

Operating Activities. Net cash provided by operating activities was $87.1 million during 2003, as compared to $65.2 million during 2002 due primarily to an increase in profitability and a $26.0 million increase in depreciation and amortization resulting from the aforementioned increase in production levels as well as depreciation on additional DP vessels placed in service. This increase was partially offset by funding from accounts receivable collections decreasing $20.3 million as receivables have grown primarily as a result of increased ERT production levels. Horizon Offshore, Inc. provided 5% of the Company's revenues during 2003. Further, receivables included $11.0 million at December 31, 2003 related to Horizon.

Net cash provided by operating activities was $65.2 million during the year ended December 31, 2002, as compared to $89.1 million during 2001. This decrease was due mainly to decreased profitability and the collection of a $10 million tax refund during 2001 from the IRS relating to the deduction of Q4000 construction costs as research and development expenditures for federal tax purposes. Depreciation and amortization also increased $10.2 million to $44.8 million due to the depreciation of new vessels placed in service during 2002 and to increased depletion related to increased production levels from ERT. This was offset by an increase in funding required for accounts receivable collections during 2002 compared to 2001.

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 construction of Deepwater Production Facilities. We incurred $95.4 million of capital investments during 2003, $312.8 million during 2002 and $162.8 million in 2001.

We incurred $93.2 million of capital expenditures during the year ended December 31, 2003 compared to $161.8 million during the prior year. Included in the capital expenditures during 2003 was $17.5 million for the purchase of ROV units to support the Canyon MSA agreement with Technip/Coflexip to provide robotic and trenching services, $39.6 million related to Gunnison development costs, including the spar, as well as $39.7 million relating to ERT's 2003 well exploitation program. Included in capital expenditures in 2002 was $29.1 million for the construction of the Q4000 and $20.8 million relating to the Intrepid DP conversion and Eclipse upgrade. Also included in 2002 was over $25 million in ERT offshore property acquisitions (see discussion below) as well as approximately $53 million related to Gunnison development costs, including the spar.

Included in the $151.3 million of capital expenditures in 2001 was $53 million for the construction of the Q4000, $33 million for the conversion of the Intrepid, $40 million relating to the purchase of two DP vessels (the 240-foot by 52-foot Mystic Viking and the 370-foot by 67-foot Eclipse), and expenditures of $20 million for initial Gunnison development costs and the ERT 2001 Well Enhancement Program. In addition, in March 2001, CDI acquired substantially all of the assets of Professional Divers of New Orleans in exchange for $11.5 million. The assets purchased included the 165-foot four-point moored DSV the Mr. Sonny, three utility vessels and associated diving equipment including two saturation diving systems. This acquisition was accounted for as a purchase with the acquisition price of $11.5 million being allocated to the assets acquired and liabilities assumed based upon their estimated fair values with the balance of the purchase price ($2.8 million) being recorded as goodwill.

In March 2003, ERT acquired additional interests, ranging from 45% to 84%, in four fields acquired last year, enabling ERT to take over as operator of one field. ERT paid $858,000 in cash and assumed Exxon/ Mobil's pro-rata share of the abandonment obligation for the acquired interests.

On August 30, 2002, ERT acquired the 74.8% working interest of Shell Exploration & Production Company in the South Marsh Island 130 (SMI 130) field. ERT paid $10.3 million in cash and assumed Shell's pro-rata share of the related decommissioning liability. ERT also completed the purchase of interests in seven Gulf of Mexico fields from Amerada Hess including its 25% ownership position in SMI 130 for $9.3 million in cash and assumption of Amerada Hess' pro-rata share of the related decommissioning liability. As a result, ERT is the operator with an effective 100% working interest in that field.

In July 2002, CDI purchased the Subsea Well Operations Business Unit of CSO Ltd., a wholly owned subsidiary of Technip-Coflexip, for approximately $72.0 million ($68.6 million cash and $3.4 million deferred tax liability assumption).

In June 2002, ERT acquired a package of offshore properties from Williams Exploration and Production. ERT paid $4.9 million and assumed the pro-rata share of the abandonment obligation for the acquired interests. The blocks purchased represent an average 30% net working interest in 26 Gulf of Mexico leases. In April 2002, ERT acquired a 100% interest in East Cameron Block 374, including existing wells, equipment and improvements. The property, located in 425 feet of water, was jointly owned by Murphy Exploration & Production Company and Callon Petroleum Operating Company. Terms included a cash payment of approximately $3 million to reimburse the owners for the inception-to-date cost of the subsea wellhead and umbilical and an overriding royalty interest in future production. Cal Dive completed the temporarily abandoned number one well and performed a subsea tie-back to host platform. The cost of completion and tie-back was approximately $7 million with first production occurring in August 2002.

In January 2002, CDI purchased Canyon, a supplier of remotely operated vehicles (ROVs) and robotics to the offshore construction and telecommunications industries. CDI purchased Canyon for cash of $52.8 million, the assumption of $9.0 million of Canyon debt (offset by $3.1 million of cash acquired), 181,000 shares of our common stock (143,000 shares of which we purchased as treasury shares during the fourth quarter of 2001) and a commitment to purchase the redeemable stock in Canyon at a price to be determined by Canyon's performance during the years 2002 through 2004 from continuing employees at a minimum purchase price of $13.53 per share.

In June 2002, CDI, along with GulfTerra Energy Partners L.P. ("GulfTerra"), formed Deepwater Gateway, L.L.C. (a 50/50 venture) to design, construct, install, own and operate a tension leg platform ("TLP") production hub primarily for Anadarko Petroleum Corporation's Marco Polo field discovery in the Deepwater Gulf of Mexico. Our share of the construction costs is estimated to be approximately $123 million (approximately $110 million of which had been incurred as of December 31, 2003). In August 2002, the Company along with GulfTerra, completed a non-recourse project financing for this venture, terms of which include a minimum equity investment for CDI of $33 million, all of which had been paid as of December 31, 2003, and is recorded as Investment in Production Facilities in the accompanying consolidated balance sheet. Terms of the financing also require CDI to guarantee a balloon payment at the end of the financing term in 2008 (estimated to be $22.5 million). The Company has not recorded any liability for this guarantee as management believes that it is unlikely the Company will be required to pay the balloon payment.

In April 2000, ERT acquired a 20% working interest in Gunnison, a Deepwater Gulf of Mexico prospect of Kerr-McGee Oil & Gas Corp. Consistent with CDI's philosophy of avoiding exploratory risk, financing for the exploratory costs of approximately $20 million was provided by an investment partnership (OKCD Investments, Ltd. or "OKCD"), the investors of which include current and former CDI senior management, in exchange for a revenue interest that is an overriding royalty interest of 25% of CDI's 20% working interest. CDI provided no guarantees to the investment partnership. The Board of Directors established three criteria to determine a commercial discovery and the commitment of Cal Dive funds: 75 million barrels (gross) of reserves, estimated development costs of $500 million consistent with 75 MBOE, and a CDI estimated shareholder return of no less than 12%. Kerr-McGee, the operator, drilled several exploration wells and sidetracks in 3,200 feet of water at Garden Banks 667, 668 and 669 (the Gunnison prospect) and encountered significant potential reserves resulting in the three criteria being achieved during 2001. The exploratory phase was expanded to ensure field delineation resulting in the investment partnership, which assumed the exploratory risk, funding approximately $20 million of exploratory drilling costs. With the sanctioning of a commercial discovery, the Company funded ongoing development and production costs. Cal Dive's share of such project development costs is estimated in a range of $110 million to $115 million ($104 million of which had been incurred by December 31, 2003) with over half of that for construction of the spar which was placed in service in December 2003. The Company's Chief Executive Officer, as a Class A limited partner of OKCD, personally owns approximately 57% of the partnership. Other executive officers of the Company own approximately 6% combined, of the partnership. OKCD has also awarded Class B limited partnership interests to key CDI employees. See footnote 8 to the Company's Consolidated Financial Statements included herein for discussion of the financing related to the spar construction. Production began in December 2003.

Financing Activities. We have financed seasonal operating requirements and capital expenditures with internally generated funds, borrowings under credit facilities, the sale of common stock and project financings. Our largest debt financing has been the MARAD debt. During 2001 and 2002, we borrowed $59.5 million and $43.9 million, respectively, on this facility bringing the total to $142.1 million at December 31, 2002. No draws were made in 2003 on this facility. The MARAD debt is payable in equal semi-annual installments beginning in August 2002 and maturing 25 years from such date. We made two such payments during 2003 totaling $2.8 million. It is collateralized by the Q4000, with Cal Dive guaranteeing 50% of the debt, and bears an interest rate which currently floats at a rate approximating AAA Commercial Paper yields plus 20 basis points (approximately 1.33% as of December 31, 2003). For a period up to ten years from delivery of the vessel in April 2002, the Company has options to lock in a fixed rate. In accordance with the MARAD debt agreements, we are required to comply with certain covenants and restrictions, including the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of December 31, 2003, we were in compliance with these covenants.

The Company has a $70 million revolving credit facility due in 2005. This facility is collateralized by accounts receivable and certain of the Company's Marine Contracting vessels, bears interest at LIBOR plus 125-250 basis points depending on CDI leverage ratios (approximately 3.0% as of December 31, 2003) and, among other restrictions, includes three financial covenants (cash flow leverage, minimum interest coverage and fixed charge coverage). As of December 31, 2003, the Company had drawn $30.2 million (a $22.4 million reduction from December 31, 2002) under this revolving credit facility and was in compliance with these covenants.

The Company has a $35 million term loan facility which was obtained to assist CDI in funding its portion of the construction costs of the spar for the Gunnison field. The loan is payable in quarterly installments of $1.75 million for three years after delivery of the spar (which was December 2003) with the remaining $15.75 million due at the end of the three years (2006). The facility bears interest at LIBOR plus 225-300 basis points depending on CDI leverage ratios (approximately 3.6% as of December 31, 2003) and includes, among other restrictions, three financial covenants (cash flow leverage, minimum interest coverage and debt to total book capitalization). The Company was in compliance with these covenants as of December 31, 2003.

In August 2003, Canyon Offshore, Ltd. (a U.K. subsidiary -- "COL"),, with a parent guarantee from Cal Dive, completed a capital lease with a bank refinancing the construction costs of a newbuild 750 horsepower trenching unit and a ROV. COL received proceeds of $12 million for the assets and agreed to pay the bank sixty monthly installment payments of $217,174 (resulting in an implicit interest rate of 3.29%). COL has an option to purchase the assets at the end of the lease term for $1. The proceeds were used to reduce the Company's revolving credit facility, which had initially funded the construction costs of the assets. This transaction has been accounted for as a capital lease under SFAS No. 13, Accounting for Leases, with the present value of the lease obligation (and corresponding asset) being reflected on the Company's consolidated balance sheet during the third quarter of 2003.

In January 2003, CDI completed the private placement of $25 million of preferred stock which is convertible into 833,334 shares of CDI common stock at $30 per share. The preferred stock was issued to a private investment firm. The preferred stock holder has the right to purchase as much as $30 million in additional preferred stock for a period of two years beginning in July 2003. The conversion price of the additional preferred stock will equal 125% of the then prevailing price of Cal Dive common stock, subject to a minimum conversion price of $30 per common share. The preferred stock has a minimum annual dividend rate of 4%, or LIBOR plus 150 basis points if greater, payable quarterly in cash or common shares at Cal Dive's option. CDI paid these dividends in 2003 on the last day of the respective quarters in cash. After the second anniversary, the holder may redeem the value of its original investments in the preferred shares to be settled in common stock at the then prevailing market price or cash at the discretion of the Company. Under certain conditions, the holder could redeem its investment prior to the second anniversary. Prior to the conversion, common shares issuable will be assessed for inclusion in the weighted average shares outstanding for the Company's diluted earnings per share under the if converted method based on the Company's common share price at the beginning of the applicable period.

In April 2003, the Company purchased approximately one-third of the redeemable stock in Canyon related to the Canyon purchase (see Investing Activities above and footnote 5 to the Company's Consolidated Financial Statements included herein for discussion of the Canyon acquisition) at the minimum purchase price of $13.53 per share ($2.7 million).

In May 2002, CDI sold 3.4 million shares of primary common stock for $23.16 per share, along with 517,000 additional shares to cover over-allotments. Net proceeds to the Company of approximately $87.2 million were used for the Coflexip Well Operations acquisition, ERT acquisitions and to retire debt under the Company's revolving line of credit.

During 2003 and 2002, we made payments of $2.4 million and $5.2 million separately on capital leases related to Canyon. The only other financing activity during 2003, 2002 and 2001 involved the exercise of employee stock options ($3.6 million, $5.9 million and $4.1 million, respectively).

The following table summarizes our contractual cash obligations as of December 31, 2003 and the scheduled years in which the obligation are contractually due:

	TOTAL	LESS THAN 1 YEAR	1-3 YEARS	3-5 YEARS	AFTER 5 YEARS
	(IN THOUSANDS)				
MARAD debt........................	$139,361	$ 3,039	$ 6,496	$ 7,382	$122,444
Gunnison term debt.................	35,000	7,000	28,000	--	--
Revolving debt.....................	30,189	--	30,189	--	--
Canyon capital leases and other....	13,357	3,698	5,644	4,015	--
Gunnison development...............	15,000	15,000	--	--	--
Investments in Deepwater Gateway, L.L.C. (A)........................	13,000	13,000	--	--	--
Operating Leases...................	12,049	8,160	3,223	378	288
Redeemable stock in subsidiary.....	4,924	2,462	2,462	--	--
Property, plant and equipment......	5,500	5,500	--	--	--
Total Cash Obligation..............	$268,380	$57,859	$76,014	$11,775	$122,732

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(A) Excludes CDI guarantee of balloon payment due in 2008 on non-recourse project financing (estimated to be $22.5 million).

In addition, in connection with our business strategy, we evaluate acquisition opportunities (including additional vessels as well as interest in offshore natural gas and oil properties and production facilities). We believe that internally-generated cash flow, borrowings under existing credit facilities and use of project financings along with other debt and equity alternatives will provide the necessary capital to meet these obligations and achieve our planned growth.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is currently exposed to market risk in three major areas: interest, commodity prices and foreign currency. Because the majority of the Company's debt at December 31, 2003 was based on floating rates, changes in interest would, assuming all other things equal, have a minimal impact on the fair market value of the debt instruments but every 100 basis points move in interest rates would result in $2.2 million of annualized interest expense or savings, as the case may be, to the Company.

COMMODITY PRICE RISK

The Company has utilized derivative financial instruments with respect to a portion of 2003 and 2002 oil and gas production to achieve a more predictable cash flow by reducing its exposure to price fluctuations. The Company does not enter into derivative or other financial instruments for trading purposes.

As of December 31, 2003, the Company has the following volumes under derivative contracts related to its oil and gas producing activities:

PRODUCTION PERIOD	INSTRUMENT TYPE	AVERAGE MONTHLY VOLUMES	WEIGHTED AVERAGE PRICE
Crude Oil:			
January - June 2004.....................	Swap	47 MBbl	$ 26.11
January - June 2004.....................	Swap	5 MBbl	$ 26.70
January - June 2004.....................	Swap	10 MBbl	$ 27.00
July - August 2004......................	Swap	20 MBbl	$ 26.00
July - December 2004....................	Swap	10 MBbl	$ 27.50
July - December 2004....................	Swap	20 MBbl	$ 27.75
Natural Gas:			
January - June 2004.....................	Collar	483,000 MMBtu	$5.00-$6.60

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

Subsequent to December 31, 2003, the Company entered into additional oil swaps for the period September through December 2004. The contracts cover 15 MBbl per month at $29.50. The Company also entered into additional natural gas costless collars for the period July through December 2004. The contracts cover 100,000 MMBtu per month at a weighted average price of $5.00 to $6.25.

FOREIGN CURRENCY EXCHANGE RATES

Because we operate in various oil and gas exploration and production regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar (primarily with respect to Well Ops (U.K.) Limited). The functional currency for Well Ops (U.K.) Limited is the applicable local currency (British Pound). Although the revenues are denominated in the local currency, the effects of foreign currency fluctuations are partly mitigated because local expenses of such foreign operations also generally are denominated in the same currency. The impact of exchange rate fluctuations during the years ended December 31, 2003 and 2002 did not have a material effect on reported amounts of revenues or net income.

Assets and liabilities of Well Ops (U.K.) Limited are translated using the exchange rates in effect at the balance sheet date, resulting in translation adjustments that are reflected in accumulated other comprehensive income (loss) in the shareholders' equity section of our balance sheet. Approximately 12% of our assets are impacted by changes in foreign currencies in relation to the U.S. dollar. We recorded gains of $5.0 million and $2.5 million, net of taxes, to our equity account for the years ended December 31, 2003 and 2002 to reflect the net impact of the decline of the U.S. dollar against the British Pound.

Canyon Offshore, the Company's ROV subsidiary, has operations in the United Kingdom and Southeast Asia sectors. Canyon conducts the majority of its affairs in these regions in U.S. dollars which it considers the functional currency. When currencies other than the U.S. dollar are to be paid or received, the resulting gain or loss from translation is recognized in the statements of operations. These amounts for the years ended December 31, 2003 and 2002, respectively, were not material to the Company's results of operations or cash flows.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT AUDITORS

To the Board of Directors and Shareholders of
Cal Dive International, Inc.:

We have audited the accompanying consolidated balance sheets of Cal Dive International, Inc. and Subsidiaries as of December 31, 2003 and 2002 and the related consolidated statements of operations, shareholders' equity and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. The consolidated financial statements of Cal Dive International, Inc. as of December 31, 2001 and for the year then ended were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on those consolidated financial statements in their report dated February 18, 2002.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Cal Dive International, Inc. and Subsidiaries at December 31, 2003 and 2002 and the consolidated results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States.

As discussed in Note 2 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" in 2002.

As discussed in Note 2 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" and Statement of Financial Accounting Standards No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity" in 2003.

ERNST & YOUNG LLP

Houston, Texas
February 23, 2004

NOTE: THE REPORT OF ARTHUR ANDERSEN LLP PRESENTED BELOW IS A COPY OF A PREVIOUSLY ISSUED ARTHUR ANDERSEN LLP REPORT AND SAID REPORT HAS NOT BEEN REISSUED BY ARTHUR ANDERSEN LLP NOR HAS ARTHUR ANDERSEN LLP PROVIDED A CONSENT TO THE INCLUSION OF ITS REPORT IN THIS FORM 10-K.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors and Shareholders of
Cal Dive International, Inc.:

We have audited the accompanying consolidated balance sheets of Cal Dive International Inc. (a Minnesota corporation) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of operations, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Cal Dive International, Inc., and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

Houston, Texas
February 18, 2002

CAL DIVE INTERNATIONAL, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2003 AND 2002

	DECEMBER 31, 2003	DECEMBER 31, 2002
	(IN THOUSANDS)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 6,378	$ --
Restricted cash	2,433	2,506
Accounts receivable -- Trade, net of revenue allowance on gross amounts billed of $8,518 and $7,156	78,733	65,743
Unbilled revenue	17,874	9,675
Other current assets	25,232	38,195
Total current assets	130,650	116,119
Property and equipment	802,694	726,878
Less -- Accumulated depreciation	(183,891)	(130,527)
	618,803	596,351
Other assets:		
Investment in production facilities -- Deepwater Gateway, L.L.C.	34,517	32,688
Goodwill, net	81,877	79,758
Other assets, net	16,995	15,094
	$ 882,842	$ 840,010
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 50,897	$ 62,798
Accrued liabilities	36,850	34,790
Current maturities of long-term debt	16,199	4,201
Total current liabilities	103,946	101,789
Long-term debt	206,632	223,576
Deferred income taxes	89,274	75,208
Decommissioning liabilities	75,269	92,420
Other long term liabilities	2,042	1,972
Total liabilities	477,163	494,965
Redeemable stock in subsidiary	--	7,528
Convertible preferred stock	24,538	--
Commitments and contingencies		
Shareholders' equity:		
Common stock, no par, 120,000 shares authorized, 51,460 and 51,060 shares issued	199,999	195,405
Retained earnings	178,718	145,947
Treasury stock, 13,602 and 13,602 shares, at cost	(3,741)	(3,741)
Accumulated other comprehensive income (loss)	6,165	(94)
Total shareholders' equity	381,141	337,517
	$ 882,842	$ 840,010

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

CAL DIVE INTERNATIONAL, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 AND 2001

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
	(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)		
Net revenues:			
Marine contracting	$258,990	$239,916	$163,740
Oil and gas production	137,279	62,789	63,401
	396,269	302,705	227,141
Cost of sales:			
Marine contracting	233,005	212,868	127,047
Oil and gas production	71,181	36,045	33,183
Gross profit	92,083	53,792	66,911
Selling and administrative expenses	35,922	32,783	21,325
Income from operations	56,161	21,009	45,586
Net Interest expense and other	3,490	1,968	1,290
Income before income taxes and change in accounting principle	52,671	19,041	44,296
Provision for income taxes	18,993	6,664	15,504
Minority Interest	--	--	(140)
Income before change in accounting principle	33,678	12,377	28,932
Cumulative effect of change in accounting principle, net	530	--	--
Net Income	34,208	12,377	28,932
Preferred stock dividends and accretion	1,437	--	--
Net income applicable to common shareholders	$ 32,771	$ 12,377	$ 28,932
Net income per common share			
Basic:			
Net income applicable to common shareholders before change in accounting principle	$ 0.86	$ 0.35	$ 0.89
Cumulative effect of change in accounting principle	0.01	--	--
Net income applicable to common shareholders	$ 0.87	$ 0.35	$ 0.89
Diluted:			
Net income applicable to common shareholders before change in accounting principle	$ 0.86	$ 0.35	$ 0.88
Cumulative effect of change in accounting principle	0.01	--	--
Net income applicable to common shareholders	$ 0.87	$ 0.35	$ 0.88
Weighted average common shares outstanding:			
Basic	37,740	35,504	32,449
Diluted	37,844	35,749	33,055

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

CAL DIVE INTERNATIONAL, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 AND 2001

(IN THOUSANDS)

	COMMON STOCK		RETAINED	TREASURY STOCK		ACCUMULATED OTHER COMPREHENSIVE	TOTAL SHAREHOLDERS'
	SHARES	AMOUNT	EARNINGS	SHARES	AMOUNT	INCOME (LOSS)	EQUITY
Balance, December 31, 2000..........	45,885	$ 93,838	$104,638	(13,640)	$(3,751)	$ --	$194,725
Net income..........................	--	--	28,932	--	--	--	28,932
Activity in company stock plans, net..............................	354	5,267	--	--	--	--	5,267
Purchase of treasury shares.........	--	--	--	(143)	(2,575)	--	(2,575)
Balance, December 31, 2001..........	46,239	99,105	133,570	(13,783)	(6,326)	--	226,349
Comprehensive income: Net income.......................	--	--	12,377	--	--	--	12,377
Foreign currency translation adjustments....................	--	--	--	--	--	2,548	2,548
Unrealized loss on commodity hedges.........................	--	--	--	--	--	(2,642)	(2,642)
Comprehensive income................							12,283
Sale of common stock, net...........	3,961	87,219	--	--	--	--	87,219
Activity in company stock plans, net..............................	860	7,376	--	--	--	--	7,376
Issuance of shares in business acquisition......................	--	1,705	--	181	2,585	--	4,290
Balance, December 31, 2002..........	51,060	195,405	145,947	(13,602)	(3,741)	(94)	337,517
Comprehensive income: Net income.......................	--	--	34,208	--	--	--	34,208
Foreign currency translations adjustments....................	--	--	--	--	--	5,044	5,044
Unrealized gain on commodity hedges.........................	--	--	--	--	--	1,215	1,215
Comprehensive income................							40,467
Convertible preferred stock dividends........................	--	--	(981)	--	--	--	(981)
Accretion of preferred stock costs............................	--	--	(456)	--	--	--	(456)
Activity in company stock plans, net..............................	400	4,594	--	--	--	--	4,594
Balance, December 31, 2003..........	51,460	$199,999	$178,718	(13,602)			

$(3,741) $ 6,165 $381,141 ======
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The accompanying notes are an integral part of these consolidated financial statements.

CAL DIVE INTERNATIONAL, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 AND 2001

YEAR ENDED DECEMBER 31,	2003	2002	2001
	(IN THOUSANDS)		
Cash flows from operating activities:			
Net income	$ 34,208	$ 12,377	$ 28,932
Adjustments to reconcile net income to net cash provided by operating activities --			
Cumulative effect of change in accounting principle	(530)	--	--
Depreciation and amortization	70,793	44,755	34,533
Deferred income taxes	18,993	6,130	15,504
Gain on sale of assets	45	(10)	(1,881)
Changes in operating assets and liabilities:			
Accounts receivable, net	(20,256)	(1,728)	(13,594)
Other current assets	5,038	(7,086)	2,760
Accounts payable and accrued liabilities	(9,808)	14,730	21,263
Income taxes receivable/payable	--	1,476	10,014
Other noncurrent, net	(11,362)	(5,443)	(8,424)
Net cash provided by operating activities	87,121	65,201	89,107
Cash flows from investing activities:			
Capital expenditures	(93,160)	(161,766)	(151,261)
Acquisition of businesses, net of cash acquired	(407)	(118,331)	(11,500)
Investment in Deepwater Gateway, L.L.C.	(1,830)	(32,688)	--
Restricted cash	73	(2,506)	2,624
Prepayments and deposits related to salvage operations	--	--	782
Proceeds from sales of property	200	483	1,530
Net cash used in investing activities	(95,124)	(314,808)	(157,825)
Cash flows from financing activities:			
Sale of common stock, net of transaction costs	--	87,219	--
Sale of convertible preferred stock, net of transaction costs	24,100	--	--
Borrowings under MARAD loan facility	--	43,899	59,494
Repayment of MARAD borrowings	(2,767)	(1,318)	--
Borrowings (repayments) on line of credit	(22,402)	52,591	--
Borrowings on term loan	5,730	29,270	--
Borrowings on capital leases	12,000	--	--
Repayment of capital leases	(2,430)	(5,183)	--
Preferred stock dividends paid	(981)	--	--
Redemption of stock in subsidiary	(2,676)	--	--
Exercise of stock options, net	3,570	5,900	4,084
Purchase of treasury stock	--	--	(2,575)
Net cash provided by financing activities	14,144	212,378	61,003
Effect of exchange rate changes on cash and cash equivalents	237	106	--
Net increase (decrease) in cash and cash equivalents	6,378	(37,123)	(7,715)
Cash and cash equivalents:			
Balance, beginning of year	--	37,123	44,838
Balance, end of year	$ 6,378	$ --	$ 37,123

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION

Cal Dive International, Inc. (Cal Dive, CDI or the Company), headquartered in Houston, Texas, is an energy services company with operations in two primary business segments: Marine Contracting and Oil & Gas Production. Within its Marine Contracting segment, CDI operates primarily in the Gulf of Mexico (Gulf), and recently in the North Sea and Asia/Pacific, with services that cover the lifecycle of an offshore oil or gas field. CDI's current diversified fleet of 22 vessels and 25 remotely operated vehicles (ROVs) and trencher systems perform services that support drilling, well completion, intervention, construction and decommissioning projects involving pipelines, production platforms, risers and subsea production systems. The Company also has a significant investment in offshore oil and gas production as well as production facilities. Operations in the Production Facilities segment should begin in 2004 with Marco Polo coming online. CDI's customers include major and independent oil and gas producers, pipeline transmission companies and offshore engineering and construction firms.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION

The accompanying consolidated financial statements include the accounts of the Company and its majority owned subsidiaries. All significant intercompany accounts and transactions have been eliminated. The Company accounts for its 50% interest in Deepwater Gateway, L.L.C. using the equity method of accounting as the Company does not have voting or operational control of this entity. The Company currently believes that it has no involvement with any variable interest entity covered by the scope of FASB Interpretation ("FIN") No. 46, Consolidation of Variable Interest Entities (see "Accounting Principles Not Yet Adopted" below).

USE OF ESTIMATES

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. On an ongoing basis the Company evaluates its estimates including those related to bad debts, investments, intangible assets and goodwill, property plant and equipment, decommissioning liabilities, income taxes, worker's compensation insurance and contingent liabilities. The Company bases its estimates on historical experience and on various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results could differ from those estimates.

GOODWILL

The Company tests for the impairment of goodwill on at least an annual basis. The Company's goodwill impairment test involves a comparison of the fair value of each of the Company's reporting units with its carrying amount. The fair value is determined using discounted cash flows and other market-related valuation models, such as earnings multiples and comparable asset market values. Prior to 2002 goodwill was amortized on a straight line basis over 25 years. In 2002 the Company discontinued the amortization of goodwill. The Company completed its annual goodwill impairment test as of November 1, 2003. The Company's goodwill impairment test involves a comparison of the fair value of each of the Company's reporting units with its carrying amount. All of the Company's goodwill as of December 31, 2003 and 2002 related to its Marine Contracting segment. None of the Company's goodwill was impaired based on the impairment test performed as of November 1, 2003. The Company will continue to test its goodwill annually on a consistent measurement date unless events occur or circumstances change between annual tests that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

PROPERTY AND EQUIPMENT

Property and equipment, both owned and under capital leases, are recorded at cost. Depreciation is provided primarily on the straight-line method over the estimated useful lives of the assets.

All of the Company's interests in oil and gas properties are located offshore in United States waters. The Company follows the successful efforts method of accounting for its interests in oil and gas properties. Under the successful efforts method, the costs of successful wells and leases containing productive reserves are capitalized. Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized.

Energy Resource Technology, Inc. ("ERT") acquisitions of producing offshore properties are recorded at the value exchanged at closing together with an estimate of its proportionate share of the discounted decommissioning liability assumed in the purchase based upon its working interest ownership percentage. In estimating the decommissioning liability assumed in offshore property acquisitions, the Company performs detailed estimating procedures, including engineering studies. See Accounting Principles Adopted in 2003 below in this footnote for discussion on accounting for decommissioning liabilities. All capitalized costs are amortized on a unit-of-production basis (UOP) based on the estimated remaining oil and gas reserves. Properties are periodically assessed for impairment in value, with any impairment charged to expense.

The following is a summary of the components of property and equipment (dollars in thousands):

	ESTIMATED USEFUL LIFE	2003	2002
Construction in progress	N/A	$ --	$ 32,943
Vessels	15 to 30	490,878	465,158
Offshore leases and equipment	UOP	292,858	210,542
Machinery, equipment and leasehold improvements	5	18,958	18,235
Total property and equipment		$802,694	$726,878

Construction in progress as of December 31, 2002 included costs incurred related to construction of the spar at Gunnison (see notes 4 and 8). The spar at Gunnison was placed in service in December 2003 and is included in offshore leases and equipment. The Company capitalized interest totaling $3.4 million, $4.4 million and $1.9 million during the years ended December 31, 2003, 2002 and 2001, respectively.

The cost of repairs and maintenance of vessels and equipment is charged to operations as incurred, while the cost of improvements is capitalized. Total repair and maintenance charges were $14.7 million, $11.5 million and $8.5 million for the years ended December 31, 2003, 2002 and 2001, respectively.

For long-lived assets to be held and used, excluding goodwill, the Company bases its evaluation on impairment indicators such as the nature of the assets, the future economic benefit of the assets, any historical or future profitability measurements and other external market conditions or factors that my be present. If such impairment indicators are present or other factors exist that indicate that the carrying amount of the asset may not be recoverable, the Company determines whether an impairment has occurred through the use of an undiscounted cash flows analysis of the asset at the lowest level for which identifiable cash flows exist. If an impairment has occurred, the Company recognizes a loss for the difference between the carrying amount and the fair value of the asset. The fair value of the asset is measured using quoted market prices or, in the absence of quoted market prices, is based on an estimate of discounted cash flows. Assets are classified as held for sale when the Company has a plan for disposal of certain assets and those assets meet the held for sale criteria.

DEFERRED DRYDOCK CHARGES

The Company accounts for regulatory (U.S. Coast Guard, American Bureau of Shipping and Det Norske Veritas) related drydock inspection and certification expenditures by capitalizing the related costs and amortizing them over the 30-month period between regulatory mandated drydock inspections and certification. During the years ended December 31, 2003, 2002 and 2001, drydock amortization expense was $4.1 million, $4.9 million and $3.1 million, respectively.

FOREIGN CURRENCY

The functional currency for the Company's foreign subsidiary, Well Ops (U.K.) Limited, is the applicable local currency (British Pound). Results of operations for this subsidiary are translated into U.S. dollars using average exchange rates during the period. Assets and liabilities of this foreign subsidiary are translated into U.S. dollars using the exchange rate in effect at the balance sheet date and the resulting translation adjustment, which was a gain of $5.0 million and $2.5 million, net of taxes of $2.8 million and $1.4 million, in 2003 and 2002, respectively, is included as accumulated other comprehensive income, a component of shareholders' equity. All foreign currency transaction gains and losses are recognized currently in the statements of operations. These amounts for the years ended December 31, 2003 and 2002 were not material to the Company's results of operations or cash flows.

Canyon Offshore, the Company's ROV subsidiary, has operations in the United Kingdom and Southeast Asia sectors. Canyon conducts the majority of its affairs in these regions in U.S. dollars which it considers the functional currency. When currencies other than the U.S. dollar are to be paid or received, the resulting gain or loss from translation is recognized in the statements of operations.

These amounts for the years ended December 31, 2003 and 2002 were not material to the Company's results of operations or cash flows.

ACCOUNTING FOR PRICE RISK MANAGEMENT ACTIVITIES

The Company's price risk management activities involve the use of derivative financial instruments to hedge the impact of market price risk exposures primarily related to its oil and gas production. All derivatives are reflected in the Company's balance sheet at fair market value.

There are two types of hedging activities: hedges of cash flow exposure and hedges of fair value exposure. The Company engages primarily in cash flow hedges. Hedges of cash flow exposure are entered into to hedge a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability. Changes in the derivative fair values that are designated as cash flow hedges are deferred to the extent that they are effective and are recorded as a component of accumulated other comprehensive income until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings in oil and gas production revenues.

The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk management objectives, strategies for undertaking various hedge transactions and the methods for assessing and testing correlation and hedge ineffectiveness. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. The Company also assesses, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in the hedging transactions are highly effective in offsetting changes in cash flows of its hedged items. The Company discontinues hedge accounting if it determines that a derivative is no longer highly effective as a hedge, or it is probable that a hedged transaction will not occur. If hedge accounting is discontinued, deferred gains or losses on the hedging instruments are recognized in earnings immediately.

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

During 2003 and 2002, the Company entered into various cash flow hedging swap and costless collar contracts to fix cash flows relating to a portion of the Company's oil and gas production. All of these qualified for hedge accounting and none extended beyond a year and a half. The aggregate fair value of the hedges was a liability of $2.2 million and $4.1 million as of December 31, 2003 and 2002, respectively. For the years ended December 31, 2003 and 2002 the Company recorded a $1.2 million gain, net of taxes of $.7 million, and a loss of $2.6 million, net of taxes of $1.4 million, respectively, in other comprehensive income (loss) within shareholders' equity as these hedges were highly effective. The balance in the fair value hedge adjustments account is recognized in earnings when the hedged item is sold.

As of December 31, 2003, the Company has the following volumes under derivative contracts related to its oil and gas producing activities:

PRODUCTION PERIOD	INSTRUMENT TYPE	AVERAGE MONTHLY VOLUMES	WEIGHTED AVERAGE PRICE
Crude Oil:			
January - June 2004.................	Swap	47 MBbl	$ 26.11
January - June 2004.................	Swap	5 MBbl	$ 26.70
January - June 2004.................	Swap	10 MBbl	$ 27.00
July - August 2004..................	Swap	20 MBbl	$ 26.00
July - December 2004................	Swap	10 MBbl	$ 27.50
July - December 2004................	Swap	20 MBbl	$ 27.75
Natural Gas:			
January - June 2004.................	Collar	483,000 MMBtu	$5.00-$6.60

Subsequent to December 31, 2003, the Company entered into additional oil swaps for the period September through December 2004. The contracts cover 15 MBbl per month at $29.50. The Company also entered into additional natural gas costless collars for the period July through December 2004. The contracts cover 100,000 MMBtu per month at a weighted average price of $5.00 to $6.25.

In June 2002, CDI signed an agreement with Coflexip to acquire the Subsea Well Operations Business Unit for 44.8 million British pounds (which at the time equaled $67.5 million) which subsequently closed in July 2002. CDI entered into a foreign currency forward contract to lock in the British Pound to U.S. dollar exchange rate. The Company accounted for this transaction with changes in its fair value reported in earnings. Accordingly, a $1.1 million gain was recorded in other income for the year ended December 31, 2002 as a result of the change in market value of the contract as of June 30, 2002. This contract settled in July 2002 for $1.1 million.

EARNINGS PER SHARE

Basic EPS is computed by dividing the net income available to common shareholders by the weighted-average shares of outstanding common stock. The calculation of diluted EPS is similar to basic EPS except that the denominator includes dilutive common stock equivalents and the income included in the numerator excludes the effects of the impact of dilutive common stock equivalents, if any. The computation of the basic and diluted per share amounts for the Company was as follows (in thousands, except per share amounts):

	YEARS ENDED DECEMBER 31,		
	2003	2002	2001
Income before change in accounting principle	$33,678	$12,377	$28,932
Preferred stock dividends and accretion	(1,437)	--	--
Net income applicable to common shareholders before change in accounting principle	$32,241	$12,377	$28,932
Weighted-average common shares outstanding:			
Basic	37,740	35,504	32,449
Effect of dilutive stock options	104	245	606
Diluted	37,844	35,749	33,055
Net income before change in accounting principle per common share:			
Basic	$ 0.86	$ 0.35	$ 0.89
Diluted	0.86	0.35	0.88

Stock options to purchase approximately 1,027,000 shares, 260,000 shares and 115,000 shares for the years ended December 31, 2003, 2002 and 2001, respectively, were not dilutive and, therefore, were not included in the computations of diluted income per common share amounts. In addition, approximately 1.1 million shares attributable to the convertible preferred stock were excluded from the year ended December 31, 2003 calculation of diluted EPS, as the effect would be anti-dilutive.

STOCK BASED COMPENSATION PLANS

In December 2002, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 148, Accounting for Stock-Based Compensation Transition and Disclosure ("SFAS No. 148"), to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. As permitted under SFAS No. 123, Accounting for Stock-Based Compensation, the Company continues to use the intrinsic value method of accounting established by Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees, to account for its stock-based compensation programs. Accordingly, no compensation expense is recognized when the exercise price of an employee stock option is equal to the Common Share market price on the grant date. The following table reflects the Company's pro forma results if SFAS No. 123 had been used for the accounting of these plans (in thousands, except per share amounts):

	YEARS ENDED DECEMBER 31,		
	2003	2002	2001
Net income applicable to common shareholders before change in accounting principle:			
As Reported	$32,241	$12,377	$28,932
Stock-based employee compensation cost, net of tax	(3,331)	(4,474)	(3,045)
Pro Forma	$28,910	$ 7,903	$25,887
Earnings per common share before change in accounting principle:			
Basic, as reported	$ 0.86	$ 0.35	$ 0.89
Stock-based employee compensation cost, net of tax	(0.09)	(0.13)	(0.09)
Basic, pro forma	$ 0.77	$ 0.22	$ 0.80
Diluted, as reported	$ 0.86	$ 0.35	$ 0.88
Stock-based employee compensation cost, net of tax	(0.09)	(0.13)	(0.09)
Diluted, pro forma	$ 0.77	$ 0.22	$ 0.79

For the purposes of pro forma disclosures, the fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used: expected dividend yields of 0 percent; expected lives ranging from three to ten years, risk-free interest rate assumed to be 4.0 percent in 2003 and 2002, and 4.5 percent in 2001, and expected volatility to be 56 percent in 2003, 59 percent in 2002, and 61 percent in 2001. The fair value of shares issued under the Employee Stock Purchase Plan was based on the 15% discount received by the employees. The weighted average per share fair value of the options granted in 2003, 2002 and 2001 was $12.74, $15.20, and $14.47, respectively. The estimated fair value of the options is amortized to pro forma expense over the vesting period.

REVENUE RECOGNITION

The Company earns the majority of marine contracting revenues during the summer and fall months. Revenues are derived from billings under contracts (which are typically of short duration) that provide for either lump-sum turnkey charges or specific time, material and equipment charges which are billed in accordance with the terms of such contracts. The Company recognizes revenue as it is earned at estimated collectible amounts. Revenues generated from specific time, materials and equipment charges contracts are generally earned over a dayrate basis and recognized as amounts are earned in accordance with contract terms. Revenues generated in the pre-operation mode before a contract commences are deferred and recognized on a straight line basis in accordance with contract terms. Direct and incremental costs associated with pre-operation activities are similarly deferred and recognized over the estimated contract period.

Revenue on significant turnkey contracts is recognized on the percentage-of-completion method based on the ratio of costs incurred to total estimated costs at completion, or achievement of certain contractual milestones if provided for in the contract. Contract price and cost estimates are reviewed periodically as work progresses and adjustments are reflected in the period in which such estimates are revised. Provisions for estimated losses on such contracts are made in the period such losses are determined. Unbilled revenue represents revenue attributable to work completed prior to year-end which has not yet been invoiced. All amounts included in unbilled revenue at December 31, 2003 are expected to be billed and collected within one year.

The Company records revenues from the sales of crude oil and natural gas when delivery to the customer has occurred and title has transferred. This occurs when production has been delivered to a pipeline or a barge lifting has occurred. The Company may have an interest with other producers in certain properties. In this case the Company uses the entitlements method to account for sales of production. Under the entitlements method the Company may receive more or less than its entitled share of production. If the Company receives more than its entitled share of production, the imbalance is treated as a liability. If the Company receives less than its entitled share, the imbalance is recorded as an asset.

REVENUE ALLOWANCE ON GROSS AMOUNTS BILLED

The Company bills for work performed in accordance with the terms of the applicable contract. The gross amount of revenue billed will include not only the billing for the original amount quoted for a project but also include billings for services provided which the Company believes are allowed under the terms of the related contract but are outside the scope of the original quote. The Company establishes a revenue allowance for these additional billings based on its collections history if conditions warrant such a reserve.

MAJOR CUSTOMERS AND CONCENTRATION OF CREDIT RISK

The market for the Company's products and services is primarily the offshore oil and gas industry. Oil and gas companies make capital expenditures on exploration, drilling and production operations offshore, the level of which is generally dependent on the prevailing view of the future oil and gas prices, which have been characterized by significant volatility. The Company's customers consist primarily of major, well-established oil and pipeline companies and independent oil and gas producers. The Company performs ongoing credit evaluations of its customers and provides allowances for probable credit losses when necessary. The percent of consolidated revenue of major customers was as follows: 2003 -- Shell Trading (US) Company (10%); Petrocom Energy Group, Ltd. (10%); 2002 -- BP Trinidad & Tobago LLC (11%); and 2001 -- Enron Corporation (10%). Marine contracting revenues from Horizon Offshore, Inc. were 5%, 10% and 18% of consolidated revenues during the years ended December 31, 2003, 2002 and 2001, respectively. Further, net trade receivables, from Horizon totaled $11.0 million and $6.9 million at December 31, 2003 and 2002, respectively.

INCOME TAXES

Deferred income taxes are based on the differences between financial reporting and the tax bases of assets and liabilities in accordance with SFAS No. 109, Accounting for Income Taxes. The statement requires, among other things, the use of the liability method of computing deferred income taxes. The liability method is based on the amount of current and future taxes payable using tax rates and laws in effect at the balance sheet date. Income taxes have been provided based upon the tax laws and rates in the countries in which operations are conducted and income is earned. A valuation allowance for deferred tax assets is recorded when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized.

STATEMENT OF CASH FLOW INFORMATION

The Company defines cash and cash equivalents as cash and all highly liquid financial instruments with original maturities of less than three months. The Company had $2.4 million of restricted cash as of December 31, 2003, of which $2.3 million represented amounts securing a performance bond which management believes will be released during 2004. During the years ended December 31, 2003, 2002 and 2001, the Company made cash payments for interest charges, totaling $2.7 million, $811,000 and $662,000, respectively, net of interest capitalized. Further, the Company made no cash payments for federal income taxes during the years ended December 31, 2003, 2002 and 2001.

ACCOUNTING PRINCIPLES ADOPTED IN 2003

On January 1, 2003, the Company adopted SFAS No. 143, Accounting for Asset Retirement Obligations, which addresses the financial accounting and reporting obligations and retirement costs related to the retirement of tangible long-lived assets. Among other things, SFAS No. 143 requires oil and gas companies to reflect decommissioning liabilities on the face of the balance sheet at fair value on a discounted basis. Prior to January 1, 2003, the Company reflected this liability on the balance sheet on an undiscounted basis.

The adoption of SFAS No. 143 resulted in a cumulative effect adjustment as of January 1, 2003 to record (i) a $33.1 million decrease in the carrying values of proved properties, (ii) a $7.4 million decrease in accumulated depreciation, depletion and amortization of property and equipment, (iii) a $26.5 million decrease in decommissioning liabilities and (iv) a $0.3 million increase in deferred income tax liabilities. The net impact of items (i) through (iv) was to record a gain of $0.5 million, net of tax, as a cumulative effect adjustment of a change in accounting principle in the Company's consolidated statements of operations upon adoption on January 1, 2003. The Company has no material assets that are legally restricted for purposes of settling its decommissioning liabilities.

The pro forma effects of the application of SFAS No. 143 as if the statement had been adopted on January 1, 2002 are presented below (in thousands, except per share amounts):

	YEARS ENDED DECEMBER 31,	
	2003	2002
Net income applicable to common shareholders as reported	$32,771	$12,377
Changes in accretion and depreciation expense	--	(649)
Cumulative effect of accounting change	(530)	--
Pro forma net income applicable to common shareholders	$32,241	$11,728
Pro forma net income per share applicable to common shareholders:		
Basic	$ 0.86	$ 0.33
Diluted	0.86	0.33
Net income per share applicable to common shareholders as reported:		
Basic	$ 0.87	$ 0.35
Diluted	0.87	0.35

The following table describes the changes in the Company's asset retirement obligations for the year ended 2003 (in thousands):

Asset retirement obligation at December 31, 2002	$ 92,420
Cumulative effect adjustment	(26,527)
Asset retirement obligation at January 1, 2003	65,893
Liability incurred during the period	6,449
Liabilities settled during the period	(5,646)
Revision in estimated cash flows	8,118
Accretion expense	3,600
Asset retirement obligation at December 31, 2003	$ 78,414

The pro forma asset retirement obligation liability balances as if SFAS No. 143 had been adopted January 1, 2002 are as follows (in thousands):

	2002
Pro forma amounts of liability for asset retirement obligation at beginning of year	$33,473
Pro forma amounts of liability for asset retirement obligation at end of year	$65,893

In April 2003, the FASB issued SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities ("SFAS No. 149"). SFAS No. 149 amended and clarified the accounting for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS No. 133. SFAS No. 149 was generally effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. The adoption of SFAS No. 149 did not have a material effect on the Company's consolidated financial statements.

In May 2003, the FASB issued SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity ("SFAS No. 150"). SFAS No. 150 requires that certain financial instruments, which under previous guidance were accounted for as equity, must now be accounted for as liabilities. The financial instruments affected include mandatorily redeemable stock, certain financial instruments that require or may require the issuer to buy back some of its shares in exchange for cash or other assets and certain obligations that can be settled with shares of stock. SFAS No. 150 was effective for all financial instruments entered into or modified after May 31, 2003 and was adopted by the Company effective July 1, 2003. As a result of this adoption, the Company reclassified the $4.9 million of Redeemable Stock in Subsidiary (see discussion in Note 5) from mezzanine classification (i.e., between liabilities and shareholders' equity on the balance sheet) to long-term debt, along with the applicable amount in current maturities of long-term debt. The adoption had no other impact on the Company's consolidated financial statements.

ACCOUNTING PRINCIPLES NOT YET ADOPTED

In January 2003, FIN No. 46 was issued which requires companies that control another entity through interests other than voting interests to consolidate the controlled entity. FIN No. 46 applies immediately to variable interest entities created after January 31, 2003. For variable interest entities created before February 1, 2003, FIN No. 46 is to be applied no later than the end of the first reporting period ending after March 15, 2004. The Interpretation requires certain disclosures in financial statements issued after January 31, 2003, if it is reasonably possible that the Company will consolidate or disclose information about variable interest entities when the Interpretation becomes effective. The Company currently believes that it has no involvement with any variable interest entity covered by the scope of FIN No 46.

OTHER MATTERS

The FASB's Emerging Issues Task Force ("EITF") currently is deliberating on EITF No. 03-O, Whether Mineral Rights Are Tangible or Intangible Assets, and EITF No. 03-S, Application of FASB Statement No. 142, Goodwill and Other Intangible Assets, to Oil and Gas Companies. These proposed statements will determine whether contract-based oil and gas mineral rights are classified as tangible or intangible assets based on the EITF's interpretation of SFAS No. 141, Business Combinations, and SFAS No. 142. Historically, the Company has classified all of its contract-based mineral rights within property, plant and equipment and has generally not identified these amounts separately. If the EITF determines that these mineral rights should be presented as intangible assets, the Company would have to reclassify its contract-based oil and gas mineral rights acquired after June 30, 2001 to intangible assets and make additional disclosures in accordance with SFAS No. 142. If The Company adopted this change, approximately $51 million and $87 million of the property, plant and equipment balance (net of accumulated depreciation, depletion and amortization) related to proved properties would be reclassified to intangible assets at December 31, 2003 and 2002, respectively. The Company has been amortizing these amounts under the unit-of-production method and would continue to amortize the mineral rights under this method. Based on its understanding of the scope of the EITF deliberations, the Company believes the adoption of this potential decision would have no material effect on its results of operations.

3. OFFSHORE PROPERTY TRANSACTIONS

In March 2003, ERT acquired additional interests from Exxon/Mobil ranging from 45% to 84%, in four fields acquired in 2002, enabling ERT to take over as operator of one field. ERT paid $858,000 in cash and assumed Exxon/Mobil's pro-rata share of the abandonment obligation for the acquired interests.

In August 2002, ERT, a wholly owned subsidiary of Cal Dive International, Inc., acquired the 74.8% working interest of Shell Exploration & Production Company in the South Marsh Island 130 (SMI 130) field ("Shell acquisition"). ERT paid $10.3 million in cash and assumed Shell's pro-rata share of the related decommissioning liability. SMI 130 consists of two blocks, located in approximately 215 feet of water, with approximately 155 wells on five 8-pile platforms.

In August 2002, ERT also completed the purchase of seven Gulf of Mexico fields from Amerada Hess (including its 25% ownership position in SMI 130) for $9.3 million in cash and assumption of Amerada Hess's pro-rata share of the related decommissioning liability. As a result, ERT took over as operator with an effective 100% working interest in that field.

In June 2002, ERT acquired a package of offshore properties from Williams Exploration and Production. ERT paid $4.9 million and assumed the pro-rata share of the abandonment obligation for the acquired interests. The blocks purchased represent an average 30% net working interest in 26 Gulf of Mexico leases.

During the second quarter of 2003, the Company completed purchase price allocations relating to the Shell acquisition as well as Amerada Hess' interest in SMI 130 and six other fields, and the June 2002 acquisition of a package of properties from Williams Exploration and Production. The allocations were based on settlement agreements as well as additional information obtained relating to certain asset retirement obligation estimates. The result was a net decrease of $1.6 million in property and equipment and had no statement of operations impact.

In April 2002, ERT acquired a 100% interest in East Cameron Block 374, including existing wells, equipment and improvements. Terms included a cash payment of approximately $3 million to reimburse the owners for the inception-to-date cost of the subsea wellhead and umbilical, and an overriding royalty interest in future production. Cal Dive completed the temporarily abandoned number one well and performed a subsea tie-back to a host platform. The cost of completion and tie-back was approximately $7 million, with first production occurring in August 2002.

As a result of 2002 offshore property acquisitions, ERT assumed net abandonment liabilities estimated at approximately $63.6 million.

ERT production activities are regulated by the federal government and require significant third-party involvement, such as refinery processing and pipeline transportation. The Company records revenue from its offshore properties net of royalties paid to the Minerals Management Service (MMS). Royalty fees paid totaled approximately $16.4 million, $9.2 million and $15.2 million for the years ended December 31, 2003, 2002, 2001 respectively. In accordance with federal regulations that require operators in the Gulf of Mexico to post an area wide bond of $3 million, the MMS has allowed the Company to fulfill such bonding requirements through an insurance policy.

During each of the past three years, ERT has sold its interests in certain fields as well as the platforms and a pipeline. An ERT operating policy provides for the sale of assets when the expected future revenue stream can be accelerated in a single transaction. The net result of these sales had no impact for the years ended December 31, 2003 and 2002 and added two cents to diluted earnings per common share for the year ended December 31, 2001. These sales were structured as Section 1031 "Like Kind" exchanges for tax purposes. Accordingly, the cash received was restricted to use for subsequent acquisitions of additional oil and gas properties.

4. RELATED PARTY TRANSACTIONS

In April 2000, ERT acquired a 20% working interest in Gunnison, a Deepwater Gulf of Mexico prospect of Kerr-McGee Oil & Gas Corp. Consistent with CDI's philosophy of avoiding exploratory risk, financing for the exploratory costs of approximately $20 million was provided by an investment partnership (OKCD Investments, Ltd. or "OKCD"), the investors of which include current and former CDI senior management, in exchange for a revenue interest that is an overriding royalty interest of 25% of CDI's 20% working interest. CDI provided no guarantees to the investment partnership. The Board of Directors established three criteria to determine a commercial discovery and the commitment of Cal Dive funds: 75 million barrels (gross) of reserves, estimated development costs of $500 million consistent with 75 MBOE, and a CDI estimated shareholder return of no less than 12%. Kerr-McGee, the operator, drilled several exploration wells and sidetracks in 3,200 feet of water at Garden Banks 667, 668 and 669 (the Gunnison prospect) and encountered significant potential reserves resulting in the three criteria being achieved during 2001. The exploratory phase was expanded to ensure field delineation resulting in the investment partnership, which assumed the exploratory risk, funding approximately $20 million of exploratory drilling costs. With the sanctioning of a commercial discovery, the Company funded ongoing development and production costs. Cal Dive's share of such project development costs is estimated in a range of $110 million to $115 million ($104 million of which had been incurred by December 31, 2003) with over half of that for construction of the spar. The Company's Chief Executive Officer, as a Class A limited partner of OKCD, personally owns approximately 57% of the partnership. Other executive officers of the Company own approximately 6% combined of the partnership. OKCD has also awarded Class B limited partnership interests to key CDI employees. See footnote 8 for discussion of the financing related to the spar construction. Production began in December 2003.

During the fourth quarter of 2000 another investment partnership composed of Company management and industry sources funded the drilling of a deep exploratory well at ERT's Vermilion 201 field. Effective January 1, 2001, ERT acquired approximately 55% of this investment partnership's interest in the reserves discovered for $2.5 million.

As part of the process of obtaining funding for the exploratory costs of the above projects, several outside third parties were solicited. Management believes that the structure of these transactions was both consistent with the guidelines and at least as favorable to the Company and ERT as could have been obtained from the third parties.

During 2003 and 2002, the Company was paid fees of $2,238,000 and $200,000, respectively, by Ocean Energy, Inc. ("Ocean"), an oil and gas industry customer of marine contracting services. A member of the Company's board of directors was a member of senior management of Ocean.

5. ACQUISITION OF BUSINESSES

CANYON OFFSHORE, INC.

In January 2002, CDI purchased Canyon, a supplier of remotely operated vehicles (ROVs) and robotics to the offshore construction and telecommunications industries. CDI purchased Canyon for cash of $52.8 million, the assumption of $9.0 million of Canyon debt (offset by $3.1 million of cash acquired), 181,000 shares of CDI common stock valued at $4.3 million (143,000 shares of which we purchased as treasury shares during the fourth quarter of 2001) and a commitment to purchase the redeemable stock in Canyon at a price to be determined by Canyon's performance during the years 2002 through 2004 from continuing employees at a minimum purchase price of $13.53 per share (or $7.5 million). The Company also agreed to make future payments relating to the tax impact on the date of redemption, whether employment continued or not. As they are employees, any share price paid in excess of the $13.53 per share will be recorded as compensation expense. These remaining shares have been classified as redeemable stock in subsidiary (debt beginning in the third quarter of 2003 -- see footnotes 2 and 8) in the accompanying balance sheet and will be adjusted to their estimated redemption value at each reporting period based on Canyon's performance. The acquisition was accounted for as a purchase with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair values, with the excess being recorded as goodwill. The allocation of the $70.5 million purchase price was as follows: ROVs and equipment ($22.9 million); net working capital assumed ($4.0 million) and goodwill ($43.6 million). The results of Canyon are included in the accompanying statements of operations since the date of the purchase, January 2, 2002. In April 2003, the Company purchased approximately one-third of the redeemable shares at the minimum purchase price of $13.53 per share. Consideration included approximately $400,000 of contingent consideration relating to tax gross-up payments paid to the Canyon employees in accordance with the purchase agreement. This amount was recorded as goodwill in the second quarter of 2003. As of December 31, 2003, goodwill related to the Canyon acquisition was approximately $44.7 million.

WELL OPS (U.K.) LIMITED

In July 2002, CDI purchased the subsea well operations business unit of CSO Ltd., a wholly owned subsidiary of Technip-Coflexip, for approximately $72.0 million ($68.6 million cash and $3.4 million deferred tax liability assumption). Well Ops (U.K.) Limited performs life of field well operations and marine construction tasks primarily in the North Sea. The assets purchased include the Seawell (a 368-foot DPDSV capable of supporting manned diving, ROVs and well operations). The acquisition was accounted for as a business purchase with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair values, with the excess being recorded as goodwill. During the fourth quarter of 2002, the Company completed its purchase price allocation, including obtaining an appraisal of the Seawell, resulting in $50 million allocated to this vessel, $1.5 million allocated to patented technology (to be amortized over 20 years) and goodwill of approximately $20.6 million as of December 31, 2002 ($22.2 million as of December 31, 2003). The results of Well Ops (U.K.) are included in the accompanying statements of operations since the date of the purchase, July 1, 2002.

6. INVESTMENT IN PRODUCTION FACILITIES -- DEEPWATER GATEWAY, L.L.C.

In June 2002, CDI, along with GulfTerra Energy Partners L.P., ("GulfTerra") formed Deepwater Gateway, L.L.C. (a 50/50 venture) to design, construct, install, own and operate a tension leg platform ("TLP") production hub primarily for Anadarko Petroleum Corporation's Marco Polo field discovery in the

Deepwater Gulf of Mexico. CDI's share of the construction costs is estimated to be approximately $123 million. In August 2002 the Company, along with GulfTerra, completed a non-recourse project financing for this venture, terms of which include a minimum CDI equity investment of $33 million, all of which had been paid as of December 31, 2003. This is recorded as Investment in Production Facilities -- Deepwater Gateway, L.L.C. in the accompanying consolidated balance sheet. Terms of the financing also require CDI to guarantee a balloon payment due at the end of the financing term in 2008 (estimated to be $22.5 million). The Company has not recorded any liability for this guarantee as management believes it is unlikely the Company will be required to pay the balloon payment.

7. ACCRUED LIABILITIES

Accrued liabilities consisted of the following as of December 31, 2003 and 2002 (in thousands):

	2003	2002
Accrued payroll and related benefits	$10,571	$ 6,874
Workers' compensation claims	2,203	1,724
Workers' compensation claims to be reimbursed	3,250	5,534
Royalties payable	6,589	3,238
Decommissioning liability	3,145	--
Hedging liability	2,194	4,064
Other	8,898	13,356
Total accrued liabilities	$36,850	$34,790

8. LONG-TERM DEBT

At December 31, 2003, $139.4 million was outstanding on the Company's long-term financing for construction of the Q4000. This U.S. Government guaranteed financing is pursuant to Title XI of the Merchant Marine Act of 1936 which is administered by the Maritime Administration ("MARAD Debt"). The MARAD Debt is payable in equal semi-annual installments beginning in August 2002 and maturing 25 years from such date. It is collateralized by the Q4000, with CDI guaranteeing 50% of the debt, and bears interest at a rate which currently floats at a rate approximating AAA Commercial Paper yields plus 20 basis points (approximately 1.33% as of December 31, 2003). For a period up to ten years from delivery of the vessel in April 2002, CDI has the ability to lock in a fixed rate. In accordance with the MARAD Debt agreements, CDI is 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, 2003 the Company was in compliance with these covenants.

The Company has a $70 million revolving credit facility ("Revolver") due in 2005. This facility is collateralized by accounts receivable and certain of the Company's Marine Contracting vessels, bears interest at LIBOR plus 125-250 basis points depending on CDI leverage ratios (approximately 3.0% as of December 31, 2003) and, among other restrictions, includes three financial covenants (cash flow leverage, minimum interest coverage and fixed charge coverage). As of December 31, 2003, the Company had drawn $30.2 million under the Revolver and was in compliance with these covenants.

The Company has a $35 million term loan facility which was obtained to assist CDI in funding its portion of the construction costs of the spar for the Gunnison field. The loan will be payable in quarterly installments of $1.75 million for three years after delivery of the spar (which was December 2003) with the remaining $15.75 million due at the end of the three years (2006). The facility bears interest at LIBOR plus 225-300 basis points depending on CDI leverage ratios (approximately 3.6% as of December 31, 2003) and includes, among other restrictions, three financial covenants (cash flow leverage, minimum interest coverage and debt to total book capitalization). The Company was in compliance with these covenants as of December 31, 2003.

In August 2003, Canyon Offshore, Ltd. (a U.K. subsidiary -- "COL"), with a parent guarantee from CDI, completed a capital lease with a bank refinancing the construction costs of a newbuild 750 horsepower trenching unit and a ROV. COL received proceeds of $12 million for the assets and agreed to pay the bank sixty monthly installment payments of $217,174 (resulting in an implicit interest rate of 3.29%). No gain or loss resulted from this transaction. COL has an option to purchase the assets at the end of the lease term for $1. The proceeds were used to reduce the Company's Revolver, which had initially funded the construction costs of the assets. This transaction has been accounted for as a capital lease ($11.1 million at December 31, 2003) under SFAS No. 13, Accounting for Leases, with the present value of the lease obligation (and corresponding asset) reflected on the Company's consolidated balance sheet beginning in the third quarter of 2003.

The Company incurred interest expense of $2.6 million, $2.3 million and $100,000 for the years ended December 31, 2003, 2002, and 2001, respectively.

Scheduled maturities of Long-term Debt outstanding as of December 31, 2003 were as follows (in thousands):

	MARAD DEBT	REVOLVER	GUNNISON TERM LOAN	CAPITAL LEASE & OTHER	TOTAL
2004	$ 3,039	$ --	$ 7,000	$ 6,160	$ 16,199
2005	3,144	30,189	7,000	5,345	45,678
2006	3,352	--	21,000	2,761	27,113
2007	3,573	--	--	2,512	6,085
2008	3,809	--	--	1,503	5,312
Thereafter	122,444	--	--	--	122,444
Long-term debt	139,361	30,189	35,000	18,281	222,831
Current maturities	(3,039)	--	(7,000)	(6,160)	(16,199)
Long-term debt, less current maturities	$136,322	$30,189	$28,000	$12,121	$206,632

9. INCOME TAXES

CDI and its subsidiaries, including acquired companies from their respective dates of acquisition, file a consolidated U.S. federal income tax return. The Company conducts its international operations in a number of locations that have varying laws and regulations with regard to taxes. Management believes that adequate provisions have been made for all taxes that will ultimately be payable. Income taxes have been provided based on the US statutory rate of 35 percent adjusted for items which are allowed as deductions for federal income tax reporting purposes, but not for book purposes. The primary differences between the statutory rate and the Company's effective rate are as follows:

YEARS ENDED DECEMBER 31,	2003	2002	2001
Statutory rate	35%	35%	35%
Foreign provision	4	--	
Foreign tax credit	--	(4)	--
Research and development tax credits	--	--	(2)
Other	1	--	2
Effective rate	36%	35%	35%

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

YEARS ENDED DECEMBER 31,	2003	2002	2001
Current	$ 500	$ 534	$ --
Deferred	18,493	6,130	15,504
	$18,993	$6,664	$15,504

	2003	2002	2001
Domestic	$20,492	$5,996	$15,504
Foreign	(1,499)	668	--
	$18,993	$6,664	$15,504

Deferred income taxes result from the effect of transactions that are recognized in different periods for financial and tax reporting purposes. The nature of these differences and the income tax effect of each as of December 31, 2003 and 2002, is as follows (in thousands):

	2003	2002
Deferred tax liabilities		
Depreciation	$131,995	$ 96,875
Prepaid and Other	13,170	7,663
Deferred tax assets		
Net operating loss carry forward	(44,716)	(27,138)
R&D credit carry forward	(18,335)	(17,084)
Reserves, accrued liabilities and other	(8,894)	(9,410)
Valuation allowance (R&D credit)	11,161	10,373
Net deferred tax liability	$ 84,381	$ 61,279

The Company effectively paid no federal income taxes in 2003, 2002 and 2001 due primarily to the deduction of Q4000 construction costs as research and development for federal tax purposes. The Company paid $1.8 million of federal income taxes during 2000, but the amount was refunded in January 2001 upon completing its research and development analysis and filing for the refund. In addition, the Company filed amended tax returns for 1998 and 1999, deducting such costs, resulting in refunds of $8.2 million which were collected in January 2001.

At December 31, 2003, the Company had $130.6 million of net operating losses. The use of these net operating losses is subject to limitations imposed by the Internal Revenue Code and is also restricted to the taxable income of the subsidiaries generating the losses. Loss carryforwards, if not utilized, will expire at various dates from 2019 through 2022.

The Internal Revenue Service ("IRS") is in the process of examining the Company's income tax returns for years 2001 and 2002, and the 2001 pre-acquisition income tax return for Canyon Offshore, Inc. The Company believes the ultimate resolution of these audits will not have a material adverse effect on its financial condition, liquidity or results of operations.

10. CONVERTIBLE PREFERRED STOCK

On January 8, 2003, CDI completed the private placement of $25 million of a newly designated class of cumulative convertible preferred stock (Series A-1 Cumulative Convertible Preferred Stock, par value $0.01 per share) that is convertible into 833,334 shares of Cal Dive common stock at $30 per share. The preferred stock was issued to a private investment firm. The preferred stockholder has the right to purchase as much as $30 million in additional preferred stock for a period of two years beginning in July 2003. The conversion price of the additional preferred stock will equal 125% of the then prevailing market price of Cal Dive common stock, subject to a minimum conversion price of $30 per common share.

The preferred stock has a minimum annual dividend rate of 4%, or LIBOR plus 150 basis points if greater, payable quarterly in cash or common shares at Cal Dive's option. CDI paid the first, second, third and fourth quarter 2003 dividends on the last day of the respective quarters in cash. After the second anniversary, the holder may redeem the value of its original investment in the preferred shares to be settled in common stock at the then prevailing market price or cash at the discretion of the Company. In the event the Company is unable to deliver registered common shares, CDI could be required to redeem in cash. Under certain conditions (the Company's stock price falling below $7.35 per share or the occurrence of a restatement in the Company's earnings), the holder could redeem its investment prior to the second anniversary.

The proceeds received from the sale of this stock, net of transaction costs, have been classified outside of shareholders' equity on the balance sheet below total liabilities. The transaction costs have been deferred and are being accreted through the statement of operations over two years. Prior to the conversion, common shares issuable will be assessed for inclusion in the weighted average shares outstanding for the Company's diluted earnings per share using the if converted method based on the Company's common share price at the beginning of the applicable period.

11. COMMITMENTS AND CONTINGENCIES

LEASE COMMITMENTS

The Company leases several facilities, ROVs and a vessel under noncancelable operating leases, with the more significant leases expiring in the years 2004 and 2005. Future minimum rentals under these leases are $12.0 million at December 31, 2003 with $8.2 million due in 2004, $2.9 million in 2005, $280,000 in 2006, $279,000 in 2007, $99,000 in 2008 and $288,000 thereafter. Total rental expense under these operating leases was $8.1 million, $6.9 million and $779,000 for the years ended December 31, 2003, 2002 and 2001, respectively.

INSURANCE

The Company carries Hull and Increased Value insurance which provides coverage for physical damage to an agreed amount for each vessel. The deductibles are based on the value of the vessel with a maximum deductible of $500,000 on the Q4000. Other vessels carry deductibles between $250,000 and $350,000. The Company also carries Protection and Indemnity insurance which covers liabilities arising from the operation of the vessel and General Liability insurance which covers liabilities arising from construction operations. The deductible on both the P&I and General Liability is $100,000 per occurrence. Onshore employees are covered by Workers' Compensation. Offshore employees, including divers and tenders and marine crews, are covered by Maritime Employers Liability insurance policy which covers Jones Act exposures and includes a deductible of $100,000 per occurrence plus a $1 million annual aggregate. In addition to the liability policies named above, the Company carries various layers of Umbrella Liability for total limits of $200,000,000 excess of primary limits. The Company's self insured retention on its medical and health benefits program for employees is $100,000 per claim.

The Company incurs workers' compensation claims in the normal course of business, which management believes are covered by insurance. The Company, its insurers and legal counsel analyze each claim for potential exposure and estimate the ultimate liability of each claim. Amounts accrued and receivable from insurance companies, above the applicable deductible limits, are reflected in other current assets in the consolidated balance sheet. Such amounts were $3.3 million and $5.5 million as of December 31, 2003 and 2002, respectively. See related accrued liabilities at footnote 7. The Company has not incurred any significant losses as a result of claims denied by its insurance carriers.

LITIGATION AND CLAIMS

The Company is involved in various routine legal proceedings, primarily involving claims for personal injury under the General Maritime Laws of the United States and the Jones Act as a result of alleged negligence. In addition, the Company from time to time incur other claims, such as contract disputes, in the normal course of business. In that regard, in 1998, one of the Company's subsidiaries entered into a subcontract with Seacore Marine Contractors Limited ("Seacore") to provide the Sea Sorceress to a Coflexip subsidiary in Canada ("Coflexip"). Due to difficulties with respect to the sea states and soil conditions the contract was terminated and an arbitration to recover damages was commenced. A preliminary liability finding has been made by the arbitrator against Seacore and in favor of the Coflexip subsidiary. The Company was not a party to this arbitration proceeding. Seacore and Coflexip settled this matter prior to the conclusion of the arbitration proceeding with Seacore paying Coflexip $6.95 million CDN. Seacore has initiated an arbitration proceeding against Cal Dive Offshore Ltd. ("CDO"), a subsidiary of Cal Dive, seeking contribution of one-half of this amount. Because only one of the grounds in the preliminary findings by the arbitrator is applicable to CDO, and because CDO holds substantial counterclaims against Seacore, it is anticipated that the Company's subsidiary's exposure, if any, should be less than $500,000.

During 2002, the Company engaged in a large construction project and in late September of that year, supports engineered by a subcontractor failed resulting in over a month of downtime for two of CDI's vessels. Management believes that under the terms of the contract the Company is entitled to indemnification for the contractual stand-by rate for the vessels during their downtime (the indemnification claim). The customer has disputed these invoices along with certain other change orders. Of the amounts billed by CDI for this project, $9.6 million had not been collected as of December 31, 2003. The Company has initiated arbitration proceedings, in accordance with the terms of the contract, to resolve this dispute.

Although the above discussed matters have the potential of significant additional liability, the Company believes that the outcome of all such matters and proceedings will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

12. EMPLOYEE BENEFIT PLANS

DEFINED CONTRIBUTION PLAN

The Company sponsors a defined contribution 401(k) retirement plan covering substantially all of its employees. The Company's contributions are in the form of cash and are determined annually as 50 percent of each employee's contribution up to 5 percent of the employee's salary. The Company's costs related to this plan totaled $785,000, $811,000 and $595,000 for the years ended December 31, 2003, 2002 and 2001, respectively.

STOCK-BASED COMPENSATION PLANS

During 2000, the Board of Directors approved a "Stock Option in Lieu of Salary Program" for the Company's Chief Executive Officer. Under the terms of the program, the participant may annually elect to receive non-qualified stock options (with an exercise price equal to the closing stock price on the date of grant) in lieu of cash compensation with respect to his base salary and any bonus earned under the annual incentive compensation program. The number of options granted is determined utilizing the Black-Scholes valuation model as of the date of grant with a risk premium included. The participant made such election for 2002 and 2001 resulting in a total of 105,000 and 180,000 options being granted during 2002 and 2001, respectively (which included bonuses earned under the annual incentive compensation program in 2001 and 2000).

During 1995, the Board of Directors and shareholders approved the 1995 Long-Term Incentive Plan, as amended (the Incentive Plan). Under the Incentive Plan, a maximum of 10% of the total shares of Common Stock issued and outstanding may be granted to key executives and selected employees who are likely to make a significant positive impact on the reported net income of the Company as well as non-employee members of the Board of Directors. The Incentive Plan is administered by a committee which determines, subject to approval of the Compensation Committee of the Board of Directors, the type of award to be made to each participant and sets forth in the related award agreement the terms, conditions and limitations applicable to each award. The committee may grant stock options, stock appreciation rights, or stock and cash awards. Options granted to employees under the Incentive Plan vest 20% per year for a five year period or 33% per year for a three year period, have a maximum exercise life of three, five or ten years and, subject to certain exceptions, are not transferable.

Effective May 12, 1998, the Company adopted a qualified, non-compensatory Employee Stock Purchase Plan ("ESPP"), which allows employees to acquire shares of common stock through payroll deductions over a six month period. The purchase price is equal to 85 percent of the fair market value of the common stock on either the first or last day of the subscription period, whichever is lower. Purchases under the plan are limited to 10 percent of an employee's base salary. Under this plan 52,572, 44,158 and 38,849 shares of common stock were purchased in the open market at a weighted average share price of $21.74, $21.86 and $22.22 during 2003, 2002 and 2001, respectively.

All of the options outstanding at December 31, 2003, have exercise prices as follows: 108,000 shares at $17.14, 107,060 at $18.06, 129,000 shares at $19.63, 205,000 shares at $21.38, 270,667 shares at $21.83, 260,419 shares at $21.88, 120,000 shares at $24.00, 80,000 shares at $26.75 and 442,956 shares ranging from $7.75 to $23.72 and a weighted average remaining contractual life of 6.37 years.

Options outstanding are as follows:

	2003		2002		2001	
	SHARES	WEIGHTED AVERAGE EXERCISE PRICE	SHARES	WEIGHTED AVERAGE EXERCISE PRICE	SHARES	WEIGHTED AVERAGE EXERCISE PRICE
Options outstanding, Beginning of year	1,990,746	$19.52	2,179,246	$13.66	2,238,600	$11.34
Granted	183,990	17.90	732,670	21.88	589,000	21.84
Exercised	(315,757)	13.38	(862,241)	7.18	(354,838)	9.43
Terminated	(135,877)	20.37	(58,929)	15.12	(293,516)	15.69
Options outstanding, December 31	1,723,102	$20.38	1,990,746	$19.52	2,179,246	$13.66
Options exercisable, December 31	936,395	$20.69	704,191	$18.76	732,787	$ 8.97

13. SHAREHOLDERS' EQUITY

The Company's amended and restated Articles of Incorporation provide for authorized Common Stock of 120,000,000 shares with no par value per share and 5,000,000 shares of preferred stock, $0.01 par value per share, in one or more series.

In May 2002, CDI sold 3.4 million shares of primary common stock for $23.16 per share, along with 517,000 additional shares to cover over-allotments.

During the fourth quarter of 2001, CDI purchased 143,000 shares of its common stock for $2.6 million.

14. BUSINESS SEGMENT INFORMATION (IN THOUSANDS)

The following summarizes certain financial data by business segment:

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
Revenues --			
Marine contracting	$258,990	$239,916	$163,740
Oil and gas production	137,279	62,789	63,401
Total	$396,269	$302,705	$227,141
Income from operations --			
Marine contracting	$ 2,528	$ 742	$ 21,705
Oil and gas production	53,633	20,267	23,881
Total	$ 56,161	$ 21,009	$ 45,586
Net interest (income) expense and other --			
Marine contracting	$ 2,873	$ 1,359	$ 739
Oil and gas production	617	609	551
Total	$ 3,490	$ 1,968	$ 1,290
Provision (benefit) for income taxes --			
Marine contracting	$		

60 $ (793) $ 7,145 Oil and gas
production............................. 18,933
7,457 8,359 -------- -------- --------
Total..
$ 18,993 $ 6,664 $ 15,504 ======== ========
========

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
Identifiable assets --			
Marine contracting	$623,095	$615,557	$457,259
Oil and gas production	259,747	224,453	37,037
Total	$882,842	$840,010	$494,296
Capital expenditures --			
Marine contracting	$ 21,569	$ 66,297	$131,062
Oil and gas production	71,591	95,469	20,199
Total	$ 93,160	$161,766	$151,261
Depreciation and amortization --			
Marine contracting	$ 32,902	$ 27,220	$ 14,586
Oil and gas production	37,891	17,535	19,947
Total	$ 70,793	$ 44,755	$ 34,533

During the year ended December 31, 2003, the Company derived approximately $48.4 million of its revenues from the U.K. sector utilizing approximately $110 million of its total assets in this region. Additionally, $33.0 million of revenues were derived from the Latin America sector during the year ended December 31, 2003. The majority of the remaining revenues were generated in the U.S. Gulf of Mexico.

15. SUPPLEMENTAL OIL AND GAS DISCLOSURES (UNAUDITED)

The following information regarding the Company's oil and gas producing activities is presented pursuant to SFAS No. 69, Disclosures About Oil and Gas Producing Activities (in thousands).

CAPITALIZED COSTS

Aggregate amounts of capitalized costs relating to the Company's oil and gas producing activities and the aggregate amount of related accumulated depletion, depreciation and amortization as of the dates indicated are presented below. The Company has no capitalized costs related to unproved properties.

	AS OF DECEMBER 31,		
	2003	2002	2001
Gunnison (net of accumulated depletion, depreciation and amortization)	$104,378	$ 63,294	$ 10,177
Proved developed properties being amortized	188,113	180,256	72,157
Less -- Accumulated depletion, depreciation and amortization	(96,086)	(71,151)	(54,482)
Net capitalized costs	$196,405	$172,399	$ 27,852

Included in capitalized costs proved developed properties being amortized is the Company's estimate of its proportionate share of decommissioning liabilities assumed relating to these properties which are also reflected as decommissioning liabilities in the accompanying consolidated balance sheets at fair value on a discounted basis.

COSTS INCURRED IN OIL AND GAS PRODUCING ACTIVITIES

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

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
Proved property acquisition costs	$ 2,687	$ 94,034	$ 4,350
Development costs	79,289	67,241	18,247
Total costs incurred	$81,976	$161,275	$22,597

RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
Revenues	$137,279	$62,789	$63,401
Production (lifting) costs	33,907	19,153	13,236
Depreciation, depletion and amortization	37,891	17,535	19,947
Selling and administrative	11,848	5,834	6,337
Pretax income from producing activities	53,633	20,267	23,881
Income tax expense	18,933	7,457	8,359
Results of oil and gas producing activities	$ 34,700	$12,810	$15,522

ESTIMATED QUANTITIES OF PROVED OIL AND GAS RESERVES

Proved oil and gas reserve quantities are based on estimates prepared by Company engineers in accordance with guidelines established by the U.S. Securities and Exchange Commission. The Company's estimates of reserves at December 31, 2003, have been audited by Huddleston & Co., independent petroleum engineers. All of the Company's reserves are located in the United States. 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, 2001, 6,829,000 Bbls of oil and 35,525,000 Mcf of gas were undeveloped, all of which is attributable to Gunnison. As of December 31, 2002, 6,375,000 Bbls of oil and 51,807,000 Mcf of gas were undeveloped, 82% of which is attributable to Gunnison. As of December 31, 2003, 7,608,000 Bbls of oil and 28,888,000 Mcf of gas were undeveloped, 72% of which is attributable to Gunnison.

RESERVE QUANTITY INFORMATION	OIL (MBBLS)	GAS (MMCF)	TOTAL (MMCFE)
Total proved reserves at December 31, 2000	1,081	21,711	28,197
Revision of previous estimates	623	4,479	8,217
Production	(743)	(9,473)	(13,931)
Purchases of reserves in place	53	1,644	1,962
Sales of reserves in place	--	(22)	(22)
Extensions and discoveries	6,844	35,597	76,661
Total proved reserves at December 31, 2001	7,858	53,936	101,084
Revision of previous estimates	(1,442)	11,049	2,397
Production	(922)	(11,062)	(16,594)
Purchases of reserves in place	6,543	31,302	70,560
Sales of reserves in place	--	--	--
Extensions and discoveries	--	--	--
Total proved reserves at December 31, 2002	12,037	85,225	157,447
Revision of previous estimates	1,942	(5,545)	6,107
Production	(1,952)	(16,208)	(27,920)
Purchases of reserves in place	6	2,657	2,693
Sales of reserves in place	0	0	--
Extensions and discoveries	488	8,531	11,459
Total proved reserves at December 31, 2003	12,521	74,660	149,786

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

The following table reflects the standardized measure of discounted future net cash flows relating to the Company's interest in proved oil and gas reserves as of December 31:

	2003	2002	2001
Future cash inflows	$ 807,868	$ 693,023	$ 261,613
Future costs -- Production	(127,530)	(129,375)	(46,031)
Development and abandonment	(145,268)	(176,094)	(147,885)
Future net cash flows before income taxes	535,070	387,554	67,697
Future income taxes	(154,046)	(106,258)	(24,223)
Future net cash flows	381,024	281,296	43,474
Discount at 10% annual rate	(71,586)	(69,569)	(22,029)
Standardized measure of discounted future net cash flows	$ 309,438	$ 211,727	$ 21,445

CHANGES IN STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

Principal changes in the standardized measure of discounted future net cash flows attributable to the Company's proved oil and gas reserves are as follows:

	2003	2002	2001
Standardized measure, beginning of year	$ 211,727	$ 21,445	$ 77,713
Sales, net of production costs	(103,372)	(43,729)	(50,165)
Net change in prices, net of production costs	102,319	69,085	(68,811)
Changes in future development costs	(3,339)	28,958	(2,421)
Development costs incurred	79,289	67,241	18,247
Accretion of discount	21,173	6,390	3,013
Net change in income taxes	(37,127)	(62,166)	30,192
Purchases of reserves in place	4,994	124,322	433
Extensions and discoveries	21,224	--	16,612
Sales of reserves in place	--	--	20
Net change due to revision in quantity estimates	11,312	899	1,604
Changes in production rates (timing) and other	1,238	(718)	(4,992)
Standardized measure, end of year	$ 309,438	$211,727	$ 21,445

16. REVENUE ALLOWANCE ON GROSS AMOUNTS BILLED

The following table sets forth the activity in the Company's Revenue Allowance on Gross Amounts Billed for each of the three years in the period ended December 31, 2003 (in thousands):

	2003	2002	2001
Beginning balance	$ 7,156	$ 4,262	$ 1,770
Additions	6,244	12,008	6,875
Deductions	(4,882)	(9,114)	(4,383)
Ending balance	$ 8,518	$ 7,156	$ 4,262

See Note 2 for a detailed discussion regarding the Company's accounting policy on the Revenue Allowance on Gross Amounts Billed and Note 11 for a discussion of a large construction project in 2002.

17. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

The offshore marine construction industry in the Gulf of Mexico is highly seasonal as a result of weather conditions and the timing of capital expenditures by the oil and gas companies. Historically, a substantial portion of the Company's services has been performed during the summer and fall months. As a result, historically a disproportionate portion of the Company's revenues and net income is earned during such period. The following is a summary of consolidated quarterly financial information for 2003 and 2002.

	QUARTER ENDED			
	MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31
	(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)			
Fiscal 2003				
Revenues	$88,900	$101,839	$103,855	$101,675
Gross profit	19,196	24,197	24,005	24,685
Income before change in accounting principle	5,851	9,275	9,299	9,253
Net income	6,381	9,275	9,299	9,253
Net income applicable to common shareholders	6,038	8,912	8,937	8,884
Net income per common share:				
Basic:				
Net income before change in accounting principle	0.15	0.24	0.24	0.23
Cumulative effect of change in accounting principle	0.01	--	--	--
Net income applicable to common shareholders	0.16	0.24	0.24	0.23
Diluted:				
Net income before change in accounting principle	0.15	0.24	0.24	0.23
Cumulative effect of change in accounting principle	0.01	--	--	--
Net income applicable to common shareholders	0.16	0.24	0.24	0.23
Fiscal 2002				
Revenues	$53,928	$ 72,305	$ 84,015	$ 92,457
Gross profit	11,118	17,185	11,573	13,916
Net income (loss)	3,001	7,214	2,952	(790)
Net income (loss) per common share:				
Basic	.09	.21	.08	(.02)
Diluted	.09	.21	.08	(.02)

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

The Company's management, with the participation of the Company's principal executive officer (CEO) and principal financial officer (CFO), evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the fiscal year ended December 31, 2003. Based on this evaluation, the CEO and CFO have concluded that the Company's disclosure controls and procedures were effective as of the end of the fiscal year ended December 31, 2003 to ensure that information that is required to be disclosed by the Company in the reports it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms. There were no changes in the Company's internal control over financial reporting that occurred during the fiscal quarter ended December 31, 2003 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Except as set forth below, the information required by this Item is incorporated by reference to the Company's definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with the Company's 2004 Annual Meeting of Shareholders. See also "Executive Officers of the Registrant" appearing in Part I of this Report.

CODE OF ETHICS

The Company has adopted a Code of Business Conduct and Ethics for all directors, officers and employees as well as a Code of Ethics for Chief Executive Officer and Senior Financial Officers specific to those officers. Copies of these documents are available at the Company's Website www.caldive.com under Corporate Governance. Interested parties may also request a free copy of these documents from:

Cal Dive International, Inc.
ATTN: Corporate Secretary
400 N. Sam Houston Parkway E., Suite 400
Houston, Texas 77060

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with the Company's 2004 Annual Meeting of Shareholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with the Company's 2004 Annual Meeting of Shareholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with the Company's 2004 Annual Meeting of Shareholders.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement to be filed pursuant to Regulation 14A under the Securities Act of 1934 in connection with the Company's 2004 Annual Meeting of Shareholders.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(1) Financial Statements

The following financial statements included on pages 42 through 72 in this Annual Report are for the fiscal year ended December 31, 2003.

Report of Independent Auditors
Report of Independent Public Accountants
Consolidated Balance Sheets as of December 31, 2003 and 2002
Consolidated Statements of Operations for the Years Ended December 31, 2003, 2002 and 2001
Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2003, 2002 and 2001
Consolidated Statements of Cash Flows for the Years Ended December 31, 2003, 2002 and 2001
Notes to Consolidated Financial Statements

All financial statement schedules are omitted because the information is not required or because the information required is in the financial statements or notes thereto.

(2) Report on Form 8-K.

Current Report on Form 8-K furnished to the SEC on November 4, 2003 to report the Company's 2003 third quarter financial results.

(3) Exhibits.

Pursuant to Item 601(b)(4)(iii), the Registrant agrees to forward to the commission, upon request, a copy of any instrument with respect to long-term debt not exceeding 10% of the total assets of the Registrant and its consolidated subsidiaries.

The following exhibits are filed as part of this Annual Report:

EXHIBITS - - ------- 3.1 Amended and Restated Articles of Incorporation of registrant, incorporated by reference to Exhibit 3.1 to the Form S-1 Registration Statement filed by registrant with the Securities and Exchange Commission on May 1, 1997 (Reg. No. 333-26357) (the "Form S-1"). 3.2 By-Laws of registrant, incorporated by reference to Exhibit 3.2 to the

Form S-1.
3.3 Articles of Correction, incorporated by reference to Exhibit 3.3 to the Form S-3 Registration Statement filed by registrant with the Securities and Exchange Commission on May 22, 2002 (Reg. No. 333-87620) (the "Form S-3").
3.4 Amendment to the 1997 Amended and Restated Articles of Incorporation of registrant, incorporated by reference to Exhibit 3.4 to the Form S-3.
3.5 Certificate of Rights and Preferences, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by registrant with the Securities and Exchange Commission on January 22, 2003 (the "Form 8-K").

EXHIBITS - -- ------ 4.1 Second Amended and Restated Loan and Security Agreement by and among Fleet Capital Corporation, Southwest Bank of Texas, N.A. and Whitney National Bank, as Lenders, and Cal Dive International, Inc., Energy Resource Technology, Inc., Aquatica, Inc. and Canyon Offshore, Inc., as Borrowers, dated February 22, 2002, incorporated by reference to Exhibit 4.1 to the registrant's Annual Report on Form 10-K for the fiscal year ended December 31, 2001, filed by the registrant with the Securities and Exchange Commission on March 28, 2002 (the "2001 Form 10-K"). 4.2 First Amendment to Second Amended and Restated Loan and Security Agreement by and among Fleet Capital Corporation, Southwest Bank of Texas, N.A. and Whitney National Bank, as Lenders, and Cal Dive International, Inc., Energy Resource Technology, Inc., Aquatica, Inc. and Canyon Offshore, Inc., as Borrowers, dated August 9, 2002, incorporated by reference to Exhibit 4.2 to the registrant's Annual Report on Form 10-K/A for the fiscal year ended December 31, 2002, filed by the registrant with the Securities and Exchange Commission on April 8, 2003 (the "2002 Form 10-K/A"). 4.3 Second Amendment to Second Amended and Restated Loan and Security Agreement by and among Fleet Capital Corporation, Southwest Bank of Texas, N.A. and Whitney National Bank, as Lenders, and Cal Dive International, Inc., Energy Resource Technology, Inc. and Canyon Offshore, Inc., as Borrowers, dated August 30, 2002, incorporated by reference to Exhibit 4.3 to the 2002 Form 10-K/A. 4.4 Third Amendment to Second Amended and Restated Loan and Security Agreement by and among Fleet Capital Corporation, Southwest Bank of Texas, N.A. and Whitney National Bank, as Lenders, and

Cal Dive International, Inc., Energy Resource Technology, Inc. and Canyon Offshore, Inc., as Borrowers, dated October 24, 2002, incorporated by reference to Exhibit 4.1 to the Form S-3 Registration Statement filed by the registrant with the Securities and Exchange Commission on February 26, 2003 (Reg. 333-103451) (the "2003 Form S-3"). 4.5 Fourth Amendment to Second Amended and Restated Loan and Security Agreement by and among Fleet Capital Corporation, Southwest Bank of Texas, N.A. and Whitney National Bank, as Lenders, and Cal Dive International, Inc., Energy Resource Technology, Inc. and Canyon Offshore, Inc., as Borrowers, dated February 14, 2003, incorporated by reference to Exhibit 4.5 to the 2002 Form 10-K/A. 4.6 Participation Agreement among ERT, Cal Dive International, Inc., Cal Dive/Gunnison Business Trust No. 2001-1 and Bank One, N.A., et. al., dated as of November 8, 2001, incorporated by reference to Exhibit 4.2 to the 2001 Form 10-K. 4.7 Form of Common Stock certificate, incorporated by reference to Exhibit 4.1 to the Form S-1. 4.8 Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of August 16, 2000, incorporated by reference to Exhibit 4.4 to the 2001 Form 10-K. 4.9 Amendment No. 1 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of January 25, 2002, incorporated by reference to Exhibit 4.9 to the 2002 Form 10-K/A. 4.10 Amendment No. 2 to Credit Agreement among Cal Dive I-Title XI, Inc., GOVCO Incorporated, Citibank N.A. and Citibank International LLC dated as of November 15, 2002, incorporated by reference to Exhibit 4.4 to the 2003 Form S-3. 4.11 First Amended and Restated Agreement dated January 17, 2003, but effective as of December 31, 2002, by and between Cal Dive International, Inc. and Fletcher International, Ltd., incorporated by reference to Exhibit 10.1 to the Form 8-K.

4.12 Amended and Restated Credit Agreement among Cal Dive/Gunnison Business Trust No. 2001-1, Energy Resource Technology, Inc., Cal Dive International, Inc., Wilmington Trust Company, a Delaware banking corporation, the Lenders party thereto, and Bank One, NA, as Agent, dated July 26, 2002, incorporated by reference to Exhibit 4.12 to the 2002 Form 10-K/A.

EXHIBITS - -- ------ 4.13 First Amendment to Amended and Restated Credit Agreement among Cal Dive/Gunnison Business Trust No. 2001-1, Energy Resource Technology, Inc., Cal Dive International, Inc., Wilmington Trust Company, a Delaware banking corporation, the Lenders party thereto, and Bank One, NA, as Agent, dated January 7, 2003, incorporated by reference to Exhibit 4.13 to the 2002 Form 10-K/A. 4.14 Second Amendment to Amended and Restated Credit Agreement among Cal Dive/Gunnison Business Trust No. 2001-1, Energy Resource Technology, Inc., Cal Dive International, Inc., Wilmington Trust Company, a Delaware banking corporation, the Lenders party thereto, and Bank One, NA, as Agent, dated February 14, 2003, incorporated by reference to Exhibit 4.14 to the 2002 Form 10-K/A. 4.15 Lease with

Purchase Option Agreement between Banc of America Leasing & Capital, LLC and Canyon Offshore Ltd. dated July 31, 2003 incorporated by reference to Exhibit 10.1 to the Form 10-Q for the fiscal quarter ended September 30, 2003, filed by the registrant with the Securities and Exchange Commission on November 13, 2003. 10.1 1995 Long Term Incentive Plan, as amended, incorporated by reference to Exhibit 10.3 to the Form S-1. 10.2 Employment Agreement between Owen Kratz and Company dated February 28, 1999, incorporated by reference to Exhibit 10.5 to the registrant's Annual Report on Form 10-K for the fiscal year ended December 31, 1998, filed by the registrant with the Securities and Exchange Commission on March 31, 1999 (Reg. 000-22739) (the "1998 Form 10-K"). 10.3 Employment Agreement between Martin R. Ferron and Company dated February 28, 1999, incorporated by reference to Exhibit

10.6 of the 1998 Form 10-K. 10.4 Employment Agreement between S. James Nelson and Company dated February 28, 1999, incorporated by reference to Exhibit 10.7 of the 1998 Form 10-K. 10.5 Employment Agreement between A. Wade Pursell and Company dated January 1, 2002, incorporated by reference to Exhibit 10.7 of the 2001 Form 10-K. 10.6* Employment Agreement between James Lewis Connor, III and Company dated May 1, 2002. 21.1 Subsidiaries of registrant -- The registrant has seven subsidiaries: Energy Resource Technology, Inc.; Canyon Offshore, Inc.; Cal Dive ROV, Inc.; Cal Dive I-Title XI, Inc.; Cal Dive Offshore, Ltd.; Well Ops (U.K.) Limited; and Well Ops Inc. 23.1* Consent of Ernst & Young LLP. 23.2* Consent of Huddleston & Co., Inc. 31.1* Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer 31.2* Certification Pursuant to

Rule 13a-14(a) under the Securities Exchange Act of 1934 by A. Wade Pursell, Chief Financial Officer 32.1* Section 1350 Certification by Owen Kratz, Chief Executive Officer 32.2* Section 1350 Certification by A. Wade Pursell, Chief Financial Officer

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* Filed herewith.

SIGNATURES

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

CAL DIVE INTERNATIONAL, INC.

By: /s/ A. WADE PURSELL

A. Wade Pursell
Senior Vice President, Chief
Financial Officer

March 12, 2004

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

SIGNATURE
TITLE DATE

----- ----
/s/ OWEN
KRATZ
Chairman,
Chief
Executive
Officer
March 12,
2004 -----

--- and
Director
(principal
executive
Owen Kratz
officer)
/s/ MARTIN
R. FERRON
President,
Chief
Operating
Officer
March 12,
2004 -----

--- and
Director
Martin R.
Ferron /s/
S. JAMES
NELSON
Vice
Chairman
and
Director
March 12,
2004 -----

--- S.
James
Nelson /s/
A. WADE
PURSELL
Senior
Vice
President

and Chief
March 12,
2004 -----

Financial
Officer
(principal
A. Wade
Pursell
financial
officer)
/s/ LLOYD
A. HAJDIK
Vice
President
--
Corporate
March 12,
2004 -----

Controller
(principal
accounting
Lloyd A.
Hajdik
officer)
/s/ GORDON
F. AHALT
Director
March 12,
2004 -----

--- Gordon
F. Ahalt
/s/
BERNARD J.
DUROC-
DANNER
Director
March 12,
2004 -----

Bernard J.
Duroc-
Danner /s/
WILLIAM L.
TRANSIER
Director
March 12,
2004 -----

William L.
Transier
/s/ JOHN
V. LOVOI
Director
March 12,
2004 -----

--- John
V. Lovoi
/s/ T.
WILLIAM
PORTER
Director
March 12,
2004 -----

--- T.
William
Porter /s/
ANTHONY
TRIPODO
Director
March 12,
2004 -----

Anthony
Tripodo

EXHIBIT INDEX

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Wade Pursell, Chief Financial Officer 32.1* Section 1350 Certification by Owen Kratz, Chief Executive Officer 32.2* Section 1350 Certification by A. Wade Pursell, Chief Financial Officer

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* Filed herewith.

AMENDED AND RESTATED
EMPLOYMENT AGREEMENT

This Amended and Restated Employment Agreement (the "Agreement") is made effective as of the 1st day of May, 2002 (the "Effective Date"), between CAL DIVE INTERNATIONAL, INC., a Minnesota corporation, ("Company"), and JAMES LEWIS CONNOR, III ("Employee"), an individual residing at 50 Highland Circle, The Woodlands, Texas 77381.

WHEREAS, Employee has extensive legal and management skills and experience applicable to the oil-field services industry and the oil and gas industry, together with other knowledge and ability beneficial to Company; and

WHEREAS, the Company wishes to continue to employ Employee as Senior Vice President, General Counsel and Secretary of Company and Employee is willing to accept such continued employment upon the terms and conditions set forth in this Agreement;

NOW, THEREFORE, in consideration of the premises and mutual covenants and agreements set forth herein, the parties hereto agree as follows:

SECTION 1. TERM OF EMPLOYMENT AND EMPLOYMENT DUTIES.

(a) Term of Employment. Employee agrees to be employed by the Company pursuant to the terms and conditions contained herein, for a period commencing on the date hereof until April 30, 2004, and thereafter terminating twelve (12) months after delivery to Employee of a written notice of termination by the Company (the "Employment Term"); provided, however, that the occurrence of any event described in Sections 7(a), 7(b) or 7(c) prior to the end of the Employment Term shall result in the immediate termination of Employee's employment and the Employment Term, subject to the terms of such applicable section. Employee shall devote Employee's time, energy and skill to the affairs of the Company and any of its affiliated business entities and to the promotion of their interests. Any provision of this Agreement to the contrary notwithstanding, Employee shall immediately resign from any offices held with the Company, or its affiliates (as that term is defined in the regulations promulgated under the Securities Exchange Act of 1934, as amended; hereinafter "Affiliates") upon written request by the Company. Any resignation made pursuant to a written request by the Company under this Section shall not affect Employee's rights under this Agreement for any compensation, benefits or payments.

(b) Duties of Employee. Employee's duties shall include all the normal duties associated with the above-described position with Company and all other responsibilities assigned from time to time by the Chairman of the Board, Board of Directors and President of the Company. During the Employment Term, (i) Employee services shall be rendered on a full time basis, (ii) Employee shall have no other employment and no substantial outside business activities and (iii) the headquarters for the performance of Employee's services shall be the principal executive or operating offices of the Company, subject to travel for such reasonable lengths of time as the performance of Employee's duties in the business of the Company may require.

SECTION 2. COMPENSATION.

(a) Salary. During the Employment Term, as compensation for Employee's services and covenants and agreements hereunder and subject to such changes therein as the Board may make from time to time, the Company agrees to pay Employee an initial salary for the period from the date hereof to April 30, 2003 at the annual rate of One Hundred Twenty-Five Thousand and No/100 Dollars ($125,000.00), payable in equal semi-monthly installments ("Salary") in accordance with the Company's regular payroll practices for its senior management executives, prorated for any partial year employment and subject to normal increases as approved by the Board adjustments; such Salary as annualized being herein referred to as "Annual Salary".

(b) Incentive Bonus. During the Employment Term, in addition to the Annual Salary payable to Employee pursuant to paragraph (a) above, Employee shall be entitled to an annual incentive bonus (the "Incentive Bonus") based on the achievement of personal, departmental and Company performance objectives, payable not later than three months after the close of each fiscal year of the Company, commencing with the fiscal year ending December 31, 2002, as established annually or from time to time by the Board of Directors, together with an additional bonus from Energy Resource Technology, Inc. of 0.2% of the Annual Net Profit of Energy Resource Technology, Inc. with such Annual Net Profit calculated on the same basis as the ERT Bonus Program for key employees of Energy Resource Technology, Inc.

(c) Reimbursement of Expenses. During the Employment Term, Employee will be reimbursed by the Company for Employee's reasonable business expenses incurred in connection with the performance of Employee's duties hereunder, including, without limitation, a home fax line, car mileage, cell phone and business calls and other expenses consistent with Company policy from time to time.

(d) Stock Options. Subject to Board approval, Employee will receive an initial award of 30,000 stock options.

SECTION 3. BENEFITS.

(a) Employee Benefits. During the Employment Term, Employee shall be entitled to participate in any medical/dental, life insurance, accidental death, long term disability insurance plan and 401(k) or other insurance and retirement plans that have been or which may be adopted by the Company (as long as such plan is not discontinued) for the general and overall benefit of executive employees of the Company, according to the participation or eligibility requirements of each such plan.

(b) Vacation and Holidays. During the Employment Term, Employee shall enjoy such vacation, holiday and similar rights and privileges as are enjoyed generally by Company's senior management executives.

SECTION 4. NONDISCLOSURE AND NONUSE OF CONFIDENTIAL INFORMATION

(a) Nondisclosure Period. During the period commencing with the date of this Agreement and ending on either: (i) the fifth anniversary of the date of the termination of Employee's employment with the Company if such termination arises as a result of: (x) the voluntary termination or retirement by Employee; or (y) the termination of Employee by the Company for Cause; or (ii) the date which is eighteen (18) months following the date of termination of Employee's employment with the Company if such termination arises for any reason other than as provided in subparagraph 4 (a)(i) above, Employee covenants and agrees with the Company that Employee shall not disclose or use any Confidential Information of which Employee is or becomes aware, whether or not such information is developed by him, except to the extent that such disclosure or use is directly related to and required by Employee's performance of duties assigned to Employee by the Company. Employee shall take all appropriate steps to safeguard Confidential Information and to protect it against disclosure, misuse, espionage, loss and theft.

(b) Confidential Information. As used in this Agreement, the term "Confidential Information" means information that is not generally known to the public and that is or has been used, developed or obtained, either prior to, on or following the date of this Agreement, by the Company in connection with its businesses, including but not limited to: (i) products or services; (ii) fees, costs and pricing structures: (iii) designs; (iv) analysis; (v) drawings, photographs and reports; (vi) computer software, including operating systems, applications and program listings; (vii) flow charts, manuals and documentation; (viii) data bases; (ix) accounting and business methods; (x) inventions, devices, new developments, methods and processes, whether patentable or unpatentable and whether or not reduced to practice; (xi) customers and clients and customer or client lists; (xii) other copyrightable works; (xiii) all technology and trade secrets; and (xiv) all similar and related information in whatever form. Confidential Information shall not include any information that has become generally available to the public through no fault or participation of Employee prior to the date that Employee proposes to disclose or use such information. Information shall not be deemed to become generally available to the public because individual portions of the information have become separately published, but only if all material features comprising such information have become publicly available in combination.

SECTION 5. NON-COMPETITION AND NON-SOLICITATION.

(a) Non-Competition. Employee acknowledges and agrees with the Company that Employee's services to the Company are unique in nature and that the Company would be irreparably damaged if Employee were to provide similar services to any person or entity competing with the Company or engaged in a similar business. Employee accordingly covenants and agrees with the Company that during the period commencing with the date of this Agreement and ending on the later to occur of: (i) April 30, 2007; and (ii) (A) the second anniversary of the date of the termination of Employee's employment with the Company if such termination arises as a result of voluntary termination or retirement by Employee or termination by the Company for Cause, or (B) the first anniversary of the date of termination of Employee's employment with the Company if such termination arises for any reason other than as provided in the preceding subparagraph 5(a)(ii)(A). Employee shall not, other than as a lawyer, directly or indirectly, either for Employee or for any other individual, corporation, partnership, joint venture or other entity, participate in any business (including, without limitation, any division, group or franchise of a larger organization) that engages or which proposes to engage in the business of providing diving services in the Gulf of Mexico or any other business actively engaged in by the Company on the date of termination of Employee's employment in the area or areas where the Company is conducting such business; provided that, until such time as the Company waives in writing any rights it may have to enforce the terms of this Section 5 (the "Waiver"), during the period commencing on the date of the termination of Employee's employment with the Company and ending on the date on which either the non-competition provisions contained in this Section 5 terminate or the Waiver is delivered to Employee, whichever is earlier, the Company will pay to Employee either the amounts due under Section 7(d), if appropriate, or an amount equal to Employee's Annual Salary as of the date Employee's employment was terminated (which will be paid over time in accordance with the Salary payment schedule in effect from time to time for senior management executives of the Company) and during such time period Employee shall be entitled to all insurance benefits received by other senior management executives of the Company. For purposes of this Agreement, the term "participate in" shall include, without limitation, having any direct or indirect interest in any corporation, partnership, joint venture or other entity, whether as a sole proprietor, owner, stockholder, partner, joint venturer, creditor or otherwise, or rendering any direct or indirect service or assistance to any individual, corporation, partnership, joint venture and other business entity (whether as a director, officer, manager, supervisor, employee, agent, consultant or otherwise) but not ownership of 2% or less of the capital stock of a public company.

(b) Non-Solicitation. Employee covenants and agrees with the Company that during the period commencing with the date of this Agreement and ending on the later to occur of (i) April 30, 2005; and (ii) (A) the second anniversary of the date of termination of Employee's employment with the Company if such termination arises as a result of voluntary termination by the Company or for Cause, or (B) the date which is eighteen (18) months following the termination of Employee's employment with the Company if such termination arises for any reason other than as provided in the preceding subparagraph 5(b)(ii)(A) above, Employee shall not, directly or indirectly, for Employee or for any other individual, corporation, partnership, joint venture or other entity, (x) make any offer of employment, solicit or hire any supervisor, employee of the Company or its affiliates or induce or attempt to induce any employee of the Company or its affiliates to leave their employ or in any way interfere with the relationship between the Company or its affiliates and any of their employees; or (y) induce or attempt to induce any supplier, licensee, licensor, franchisee, or other business relation of the Company or its affiliates to cease doing business with them or in any way interfere with the relationship between the Company or its affiliates and any customer or business relation.

(c) Other Non-Competition Agreements. Employee represents and warrants to the Company that Employee is not a party to any agreement containing a non-competition provision or other restriction with respect to (a) the nature of any services or business which Employee is entitled to perform or conduct for the Company or (b) the disclosure or use of any information which, directly or indirectly, relates to the nature of the business of the Company or the services to be rendered by the Employee to the Company.

(d) Duty to Inform. For the period of one (1) year immediately following the end of Employee's employment with the Company, Employee agrees to inform each new employer, prior to accepting employment, of the existence of this agreement and provide that employer with a copy of it. In addition, Employee hereby authorizes the Company to forward a copy of this Agreement to any actual or prospective new employer.

SECTION 6. COMPANY'S OWNERSHIP OF INTELLECTUAL PROPERTY.

(a) Company Intellectual Property. In the event that Employee as part of Employee's activities on behalf of the Company generates, authors or contributes to any invention, design, new development, device, product, method or process (whether or not patentable or reduced to practice or comprising Confidential Information), any copyrightable work (whether or not comprising Confidential Information) or any other form of Confidential Information relating directly or indirectly to the Company's business as prior hereto, now or hereinafter conducted (collectively, "Intellectual Property"), Employee acknowledges that such Intellectual Property is the exclusive property of the Company and hereby assigns all right, title and interest in and to such Intellectual Property to the Company. Any copyrightable work prepared in whole or in part by Employee shall be deemed a work made for hire under Section 201(b) of the 1976 Copyright Act, and the Company shall own all of the rights comprised in the copyright therein. Employee shall promptly and fully disclose all Intellectual Property to the Company and shall cooperate with the Company to protect the Company's interest in and rights to such Intellectual Property, including without limitation providing reasonable assistance in securing patent protection and copyright registrations and executing all documents as reasonably requested by the Company, whether such requests occur prior to or after termination of Employee's employment with the Company.

(b) Return of Confidential Information. As requested by the Company from time to time and upon the termination of Employee's employment with the Company for any reason, Employee shall promptly deliver to the Company all copies and embodiments, in whatever form, of all Confidential Information or Intellectual Property in Employee's possession or within Employee's control (including, but not limited to, written records, notes, photographs, manuals, notebooks, documentation, program listings, flow charts, magnetic media, disks, diskettes, tapes and all other materials containing any Confidential Information or Intellectual Property) irrespective of the location or form of such material and, if requested by the Company, shall provide the Company with written confirmation that all such materials have been delivered to the Company.

SECTION 7. TERMINATION OF AGREEMENT.

(a) Termination for Cause. This Agreement may be terminated by the Company at any time during the Employment Term for Cause, in which event Employee shall have no further rights under this Agreement (but the Company's rights shall survive as herein otherwise herein provided including, without limitation, rights under Sections 4, 5 and 6). For purposes of the preceding sentence, Cause shall mean: (i) any breach or threatened breach by Employee of any of Employee's agreements contained in Sections 4, 5 or 6; (ii) repeated or willful neglect by Employee in performing any duty or carrying out any responsibility assigned or delegated to him pursuant to Section 1(b) hereof, which neglect shall not have permanently ceased within ten (10) business days after written notice to Employee thereof; or (iii) the commission by Employee of any criminal act involving moral turpitude or a felony that results in an arrest or indictment, or the commission by Employee, based on reasonable proof, of any act of fraud or embezzlement involving the Company or its customers or suppliers. In the event that the Company elects to terminate this Agreement for Cause, it will give Employee written notice of such termination.

(b) Termination Upon Death. This Agreement shall terminate automatically upon the death of Employee during the Employment Term. In such event, the Company shall be obligated to pay to Employee's estate, or to such person or persons as Employee may designate in writing to the Company, (i) through the last day of the fiscal year in which Employee's death shall have occurred, the salary (payable in the same manner as described in Section 2(a) hereof) to which Employee would have been entitled under Section 2(a) hereof had such death not occurred, and (ii) as soon as reasonably practicable after Employee's death, any accrued but, as of the date of such death, unpaid Incentive Bonus (or, if such death shall have occurred after the first three (3) months of the Company's fiscal year, any prorated portion thereof).

(c) Termination Upon Disability. This Agreement may be terminated by the Company at any time during the Employment Term in the event that Employee shall have been unable, because of Disability, to perform Employee's principal duties for the Company for a cumulative period of six (6) months within any eighteen (18) month period. Prior to Employee's termination for Disability as provided herein, Employee shall remain eligible to receive the compensation and benefits set forth in Section 2 and Section 3 hereof. Upon such termination, Employee shall be entitled to receive as soon as reasonably practicable thereafter, any accrued, but as of the date of such termination, unpaid Incentive Bonus (or, if such termination shall have occurred after the first three (3) months of the Company's fiscal year, any prorated portion thereof). For purposes of this Section 7(c), Disability shall mean any physical or mental condition of Employee which shall substantially impair Employee's ability to perform Employee's principal duties hereunder. In the event that the Company elects to terminate this Agreement by reason of Disability under this Section 7(c), it will give written notice of such termination, and, at the Company's discretion, Employee's employment will terminate sixty (60) days thereafter.

(d) Termination by the Company Without Cause After Change in Control. If the Company terminates this Agreement for any reason other than pursuant to the terms of Sections 7(a), 7(b), or 7(c), and such termination occurs within six (6) months after the occurrence of a Change in Control and a Material Change in Senior Management, then, in addition to any amounts otherwise due under this Agreement, the Company shall: (1) pay to Employee an amount equal to two times Salary together with an amount equal to the Incentive Bonus paid to Employee for Employee's last complete year of employment; (2) continue Employee's participation in the Company's medical, dental, accidental death, and life insurance plans, as provided in Section 3 of this Agreement, for two (2) years, subject to COBRA required benefits thereafter; and (3) cause Employee to be fully vested in any stock options or stock grants held by Employee. The Company shall make the payment due in one lump sum within ten (10) days of the effective date of termination.

A "Change in Control" shall be deemed to have occurred at any time after the date of this Agreement that any person (including those persons who own more than 10% of the combined voting power of the Company's outstanding voting securities on the date hereof) becomes the beneficial owner, directly or indirectly, of 45% or more of the combined voting power of the Company's then outstanding voting securities.

A "Material Change in Senior Management" shall mean any one or both of the CEO and COO cease their employment with the Company.

(e) Termination by Employee with Good Cause after Change in Control. If Employee terminates this Agreement for Good Cause and such termination occurs within two (2) years of the occurrence of a Change in Control, then, in addition to any amounts otherwise due under this Agreement, the Company shall: (1) pay to Employee an amount equal to two times Salary together with an amount equal to the Incentive Bonus paid to Employee for Employee's last complete year of employment; (2) continue Employee's participation in the Company's medical, dental, accidental death, and life insurance plans, as provided in Section 3 of this Agreement, for two (2) years, subject to COBRA required benefits thereafter, and (3) cause Employee to be fully vested in any stock options or stock grants held by Employee. The Company shall make the payment due in one lump sum within ten (10) days of the effective date of termination.

"Good Cause" shall mean the occurrence of both of the following events: (1) a Material Change in Senior Management; together with (2) any of the following:

(i) the assignment by the Company to Employee of duties that are materially inconsistent with Employee's office with the Company at the time of such assignment, or the removal by the Company from Employee of a material portion of those duties usually appertaining to Employee's office with the Company at the time of such removal;

(ii) a material change by the Company, without Employee's prior written consent, in Employee's responsibilities to the Company, as such responsibilities are ordinarily and customarily required from time to time of a senior officer of a corporation engaged in the Company's business;

(iii) any removal of Employee from, or any failure to reelect or to reappoint Employee to, the office stated in Section 1(b);

(iv) The Company's direction that Employee discontinue service (or not seek reelection or reappointment) as a director, officer or member of any corporation or association of which Employee is a director, officer, or member at the date of this Agreement;

(v) a reduction by the Company in the amount of Employee's salary in effect at the time of the occurrence of a Change in Control or the failure of the Company to pay such salary to Employee at the time and in the manner specified in this Agreement;

(vi) the discontinuance (without comparable replacement) or material reduction by the Company of Employee's participation in any bonus or other employee benefit arrangement (including, without limitation, any profit-sharing, thrift, life insurance, medical, dental, hospitalization, stock option or retirement plan or arrangement) in which Employee is a participant under the terms of this Agreement, as in effect on the date hereof or as may be improved from time to time hereafter;

(vii) the moving by the Company of Employee's principal office space, related facilities, or support personnel, from the Company's principal operating offices, or the Company's requiring Employee to perform a majority of Employee's duties outside the Company's principal operating offices for a period of more than 30 consecutive days;

(viii) the relocation, without Employee's prior written consent, of the Company's principal Employee offices to a location outside the county in which such offices are located at the time of the signing of this Agreement;

(ix) in the event the Company requires Employee to reside at a location more than twenty-five (25) miles from the Employee's principal offices, except for occasional travel in connection with the Company business to an extent and in a manner which is substantially consistent with Employee's current business travel obligations;

(x) in the event Employee consents to a relocation of the Employee's principal offices, the failure of the Company to (A) pay or reimburse Employee on an after-tax basis for all reasonable moving expenses incurred by Employee in connection with such relocation or (B) indemnify Employee on an after-tax basis against any loss realized by Employee on the sale of Employee's principal residence in connection with such relocation;

(xi) the failure of the Company to continue to provide Employee with office space, related facilities and support personnel (including, without limitation, administrative and secretarial assistance) that are commensurate with Employee's responsibilities to and position with the Company, and no less than those prior to this Agreement;

(xii) any significant change in Employee's reporting relationships or changes in senior management of the Company; or

(xiii) the failure by the Company to promptly reimburse Employee for the reasonable business expenses incurred by Employee in the performance of Employee's duties for the Company, in accordance with this Agreement.

(f) Gross-Up Payments - Certain Additional Payments by the Company.

(i) Anything in this Agreement to the contrary notwithstanding, in the event it shall be determined that any payment or distribution by the Company, or any of its Affiliates, under this Agreement to or for the benefit of Employee (any such payments or distributions being individually referred to herein as a Payment, and any two or more of such payments or distributions being referred to herein as Payments), would be subject to the excise tax imposed by Section 4999 of the Internal Revenue Code (the "Code"; such excise tax, together with any interest thereon, any penalties, additions to tax, or additional amounts with respect to such excise tax, and any interest in respect of such penalties, additions to tax or additional amounts, being collectively referred herein to as the "Excise Tax"), then Employee shall be entitled to receive an additional payment or payments (individually, a "Gross-Up Payment" with any two or more of such additional payments being referred to "Gross-Up Payments") in an amount such that after payment by Employee of all Excise Taxes imposed upon the Payment(s) and, if applicable, Gross-Up Payment(s), Employee retains a total amount of Gross-Up Payments, whether one or more, equal to the Excise Tax imposed upon the Payment(s) and, if applicable, Gross-Up Payment(s).

(ii) Subject to the provisions of Section 7(f)(iii) through 7(f)(ix), any determination ("Determination") required to be made under this Section 7(f)(ii), including whether a Gross-Up Payment is required and the amount of such Gross-Up Payment, shall initially be made, at the Company's expense, by nationally recognized tax counsel mutually acceptable to the Company and Employee ("Tax Counsel"). Tax Counsel shall provide detailed supporting legal authorities, calculations, and documentation both to the Company and Employee within fifteen (15) business days of the termination of Employee's employment, if applicable, or such other time or times as is reasonably requested by the Company or Employee. If Tax Counsel makes the initial Determination that no Excise Tax is payable by Employee with respect to a Payment or Payments, it shall furnish Employee with an opinion reasonably acceptable to Employee that no Excise Tax will be imposed with respect to any such Payment or Payments. Employee shall have the right to dispute any Determination (a "Dispute") within fifteen (15) business days after delivery of Tax Counsel's opinion with respect to such Determination. The Gross-Up Payment, if any, as determined pursuant to such Determination shall, at the Company's expense, be paid by the Company to Employee within five (5) business days of Employee's receipt of such Determination. The existence of a Dispute shall not in any way affect Employee's right to receive the Gross-Up Payment in accordance with such Determination. If there is no Dispute, such Determination shall be binding, final and conclusive upon the Company and Employee, subject in all respects, however, to the provisions of Section 7(f)(iii) through 7(f)(ix) below. As a result of the uncertainty in the application of Sections 4999 and 280G of the Code, it is possible that Gross-Up Payments (or portions thereof) which will not have been made by the Company should have been made ("Underpayment"), and if upon any reasonable written request from Employee or the Company to Tax Counsel, or upon Tax Counsel's own initiative, Tax Counsel, at the Company's expense, thereafter determines that Employee is required to make a payment of any Excise Tax or any additional Excise Tax, as the case may be, Tax Counsel shall, at the Company's expense, determine the amount of the Underpayment that has occurred and any such Underpayment shall be promptly paid by the Company to Employee.

(iii) the Company shall release, defend, indemnify and hold harmless Employee on a fully grossed-up after-tax basis from and against any and all claims, losses, liabilities, obligations, damages, impositions, assessments, demands, judgments, settlements, costs and expenses (including reasonable attorneys', accountants', and experts' fees and expenses) with respect to any Tax liability of Employee resulting from any Final Determination that any Payment is subject to the Excise Tax.

(iv) If a party hereto receives any written or oral communication with respect to any question, adjustment, assessment or pending or threatened audit, examination, investigation or administrative, court or other proceeding which, if pursued successfully, could result in or give rise to a claim by Employee against the Company under this Section 7(f) ("Claim"), including, but not limited to, a claim for indemnification of Employee by the Company under Section 7(f)(iii), then such party shall promptly notify the other party hereto in writing of such Claim ("Tax Claim Notice").

(v) If a Claim is asserted against Employee ("Employee Claim"), Employee shall take or cause to be taken such action in connection with contesting such Employee Claim as the Company shall reasonably request in writing from time to time, including the retention of counsel and experts as are reasonably designated by the Company (it being understood and agreed by the parties hereto that the terms of any such retention shall expressly provide that the Company shall be solely responsible for the payment of any and all fees and disbursements of such counsel and any experts) and the execution of powers of attorney, provided that:

(1) within thirty (30) calendar days after the Company receives or delivers, as the case may be, the Tax Claim Notice relating to such Employee Claim (or such

earlier date that any payment of the Taxes claimed is due from Employee, but in no event sooner than five (5) calendar days after the Company receives or delivers such Tax Claim Notice), the Company shall have notified Employee in writing ("Election Notice") that the Company does not dispute its obligations (including, but not limited to, its indemnity obligations) under this Agreement and that the Company elects to contest, and to control the defense or prosecution of, such Employee Claim at the Company's sole risk and sole cost and expense; and

(2) the Company shall have advanced to Employee on an interest-free basis, the total amount of the Tax claimed in order for Employee, at the Company's request, to pay or cause to be paid the Tax claimed, file a claim for refund of such Tax and, subject to the provisions of the last sentence of Section 7(f)(vii), sue for a refund of such Tax if such claim for refund is disallowed by the appropriate taxing authority (it being understood and agreed by the parties hereto that the Company shall only be entitled to sue for a refund and the Company shall not be entitled to initiate any proceeding in, for example, United States Tax Court) and shall indemnify and hold

Employee harmless, on a fully grossed-up after-tax basis, from any Tax imposed with respect to such advance or with respect to any imputed income with respect to such advance; and

(3) the Company shall reimburse Employee for any and all costs and expenses resulting from any such request by the Company and shall indemnify and hold Employee harmless, on fully grossed-up after-tax basis, from any Tax imposed as a result of such reimbursement.

(vi) Subject to the provisions of Section 7(f)(v) hereof, the Company shall have the right to defend or prosecute, at the sole cost, expense and risk of the Company, such Employee Claim by all appropriate proceedings, which proceedings shall be defended or prosecuted diligently by the Company to a Final Determination; provided, however, that (i) the Company shall not, without Employee's prior written consent, enter into any compromise or settlement of such Employee Claim that would adversely affect Employee, (ii) any request from the Company to Employee regarding any extension of the statute of limitations relating to assessment, payment, or collection of Taxes for the taxable year of Employee with respect to which the contested issues involved in, and amount of, Employee Claim relate is limited solely to such contested issues and amount, and (iii) the Company's control of any contest or proceeding shall be limited to issues with respect to Employee Claim and Employee shall be entitled to settle or contest, in Employee's sole and absolute discretion, any other issue raised by the Internal Revenue Service or any other taxing authority. So long as the Company is diligently defending or prosecuting such Employee Claim, Employee shall provide or cause to be provided to the Company any information reasonably requested by the Company that relates to such Employee Claim, and shall otherwise cooperate with the Company and its representatives in good faith in order to contest effectively such Employee Claim. the Company shall keep Employee informed of all developments and events relating to any such Employee Claim (including, without limitation, providing to Employee copies of all written materials pertaining to any such Employee Claim), and Employee or Employee's authorized representatives shall be entitled, at Employee's expense, to participate in all conferences, meetings and proceedings relating to any such Employee Claim.

(vii) If, after actual receipt by Employee of an amount of a Tax claimed (pursuant to an Employee Claim) that has been advanced by the Company pursuant to Section 7(f)(v)(2) hereof, the extent of the liability of the Company hereunder with respect to such Tax claimed has been established by a Final Determination, Employee shall promptly pay or cause to be paid to the Company any refund actually received by, or actually credited to, Employee with respect to such Tax (together with any interest paid or credited thereon by the taxing authority and any recovery of legal fees from such taxing authority related thereto), except to the extent that any amounts are then due and payable by the Company to Employee, whether under the provisions of this Agreement or otherwise. If, after the receipt by Employee of an amount advanced by the Company pursuant to Section 7(f)(v)(2), a determination is made by the Internal Revenue Service or other appropriate taxing authority that Employee shall not be entitled to any refund with respect to such Tax claimed, and the Company does not notify Employee in writing of its intent to contest such denial of refund prior to the expiration of thirty (30) days after such determination, then such advance shall be forgiven and shall not be required to be repaid and the amount of such advance shall offset, to the extent thereof, the amount of any Gross-Up Payments and other payments required to be paid hereunder.

(viii) With respect to any Employee Claim, if the Company fails to deliver an Election Notice to Employee within the period provided in Section 7(f)(v)(1) hereof or, after delivery of such Election Notice, the Company fails to comply with the provisions of Section 7(f)(v)(2) and (3) and 7(f)(vi) hereof, then Employee shall at any time thereafter have the right (but not the obligation), at Employee's election and in Employee's sole and absolute discretion, to defend or prosecute, at the sole cost, expense and risk of the Company, such Employee Claim. Employee shall have full control of such defense or prosecution and such proceedings, including any settlement or compromise thereof. If requested by Employee, the Company shall cooperate, and shall cause its Affiliates to cooperate, in good faith with Employee and Employee's authorized representatives in order to contest effectively such Employee Claim. the Company may attend, but not participate in or control, any defense, prosecution, settlement or compromise of any Employee Claim controlled by Employee pursuant to this Section 7(f)(viii) and shall bear its own costs and expenses with respect thereto. In the case of any Employee Claim that is defended or prosecuted by Employee, Employee shall, from time to time, be entitled to current payment, on a fully grossed-up after-tax basis, from the Company with respect to costs and expenses incurred by Employee in connection with such defense or prosecution.

(ix) In the case of any Employee Claim that is defended or prosecuted to a Final Determination pursuant to the terms of this Section 7(f)(ix), the Company shall pay, on a fully grossed-up after-tax basis, to Employee in immediately available funds the full amount of any Taxes arising or resulting from or incurred in connection with such Employee Claim that have not theretofore been paid by the Company to Employee, together with the costs and expenses, on a fully grossed-up after-tax basis, incurred in connection therewith that have not theretofore been paid by the Company to Employee, within ten (10) calendar days after such Final Determination. In the case of any Employee Claim not covered by the preceding sentence, the Company shall pay, on a fully grossed-up after-tax basis, to Employee in immediately available funds the full amount of any Taxes arising or resulting from or incurred in connection with such Employee Claim at least ten calendar days before the date payment of such Taxes is due from Employee, except where payment of such Taxes is sooner required under the provisions of this Section 7(f)(ix), in which case payment of such Taxes (and payment, on a fully grossed-up after-tax basis, of any costs and expenses required to be paid under this Section 7(f)(ix)) shall be made within the time and in the manner otherwise provided in this Section 7(f)(ix).

(x) For purposes of this Agreement, the term "Final Determination" shall mean (A) a decision, judgment, decree or other order by a court or other tribunal with appropriate jurisdiction, which has become final and non-appealable; (B) a final and binding settlement or compromise with an administrative agency with appropriate jurisdiction, including, but not limited to, a closing agreement under Section 7121 of the Code; (C) any disallowance of a claim for refund or credit in respect to an overpayment of Tax unless a suit is filed on a timely basis; or (D) any final disposition by reason of the expiration of all applicable statutes of limitations.

(xi) For purposes of this Agreement, the terms "Tax" and "Taxes" mean any and all taxes of any kind whatsoever (including, but not limited to, any and all Excise Taxes, income taxes, and employment taxes), together with any interest thereon, any penalties, additions to tax, or additional amounts with respect to such taxes and any interest in respect of such penalties, additions to tax, or additional amounts.

(g) Effect of Termination. In the event that the Employee is terminated pursuant to any paragraph of this Section 7, Employee shall thereafter have no further rights under this Agreement, except for those explicitly set forth in the particular paragraph of this Section 7 which served as the basis for such termination. Notwithstanding any such termination, the covenants and agreements of Employee contained in Sections 4, 5(a) (so long as payments under Section 5(a) are continued as therein described), 5(b) and 6 hereof shall survive and remain in full force and effect.

SECTION 8. NOTICES.

(a) Notices. All notices, requests, demands and other communications hereunder must be in writing and shall be deemed to have been duly given if delivered by hand, sent to the recipient by reputable express courier service (charge prepaid), or mailed by first class, registered mail, return receipt requested, postage and registry fees prepaid and addressed as follows:

If to Employee: At the address set forth on page 1 hereof.

If to the Company: Cal Dive International, Inc.
400 North Belt East, Suite 400
Houston, Texas 77060
Attention: President

(b) Change of Address. Addresses may be changed by notice in writing signed by the addressee.

SECTION 9. GENERAL PROVISIONS.

(a) Company Subsidiaries. For purposes of this Agreement, the term Company shall include all subsidiaries of the Company.

(b) Severability. Whenever possible, each provision of this Agreement shall be interpreted in such manner as to be effective and valid under applicable law, but if any provision of this Agreement is held to be invalid, illegal or unenforceable in any respect under any applicable law or rule in any jurisdiction, such invalidity, illegality or unenforceability shall not affect any other provisions of any other jurisdiction, and this Agreement shall be reformed, construed and enforced in such jurisdictions as if such invalid, illegal or unenforceable provision had never been contained herein. The parties agree that a court of competent jurisdiction making a determination of the invalidity or unenforceability of any term or provision of Sections 4, 5 and 6 of this Agreement shall have the power to reduce the scope, duration or area of any such term or provision, to delete specific words or phrases or to replace any invalid or unenforceable term or provision in Sections 4, 5, 6 with a term or provision that is valid and enforceable and that comes closest to expressing the intention of the invalid or unenforceable term or provision, and this Agreement shall be enforceable as so modified.

(c) Complete Agreement. This Agreement, embodies the complete agreement and understanding among the parties and supersedes and preempts any prior understandings, agreements or representations by or among the parties, written or oral, which may have related to the subject matter hereof in any way.

(d) Counterparts. This Agreement may be executed in separate counterparts, each of which is deemed to be an original and all of which taken together constitute one and the same agreement.

(e) Successors and Assigns. Except as otherwise provided herein, this Agreement shall bind and inure to the benefit of and be enforceable by the Company and Employee and their respective successors and assigns; provided that the rights and obligations of Employee under this Agreement shall not be assignable without the prior written consent of the Company.

(f) Governing Law. All questions concerning the construction, validity and interpretation of this Agreement and the exhibits hereto shall be governed by the internal law, and not the law of conflicts, of the State of Texas.

(g) Remedies. Each of the parties to this Agreement shall be entitled to enforce its rights under this Agreement specifically, to recover damages and costs (including reasonable attorneys fees) caused by any breach of any provision of this Agreement and to exercise all other rights existing in its favor. The parties hereto agree and acknowledge that Employee's breach of any term or provision of this Agreement shall materially and irreparably harm the Company, that money damages shall accordingly not be an adequate remedy for any breach of the provisions of this Agreement and that any party in its sole discretion and in addition to any other remedies it may have at law or in equity may apply to any court of law or equity of competent jurisdiction (without posting any bond or deposit) for specific performance and/or other injunctive relief in order to enforce or prevent any violations of the provisions of this Agreement.

(h) Amendment and Waiver. The provisions of this Agreement may be amended and waived only with the prior written consent of the Company and Employee.

IN WITNESS, WHEREOF, the parties hereto have duly executed this Agreement as of the date first above written.

CAL DIVE INTERNATIONAL, INC.		EMPLOYEE
By:	/s/ MARTIN R. FERRON	/s/ JAMES LEWIS CONNOR, III
Name:	Martin R. Ferron	James Lewis Connor, III
Title:	President and Chief Operating Officer	

EXHIBIT 23.1

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-103451) and Form S-8 (Nos. 333-58817, 333-50289 and 333-50205) of Cal Dive International, Inc. of our report dated February 23, 2004, with respect to the consolidated financial statements of Cal Dive International, Inc. included in this Annual Report (Form 10-K) for the year ended December 31, 2003.

/s/ Ernst & Young LLP

Houston, Texas
March 11, 2004

EXHIBIT 23.2

[Letterhead of Huddleston & Co., Inc.]

March 9, 2004

Cal Dive International, Inc.
400 North Sam Houston Parkway East
Suite 400
Houston, TX 77060

Re: Cal Dive International, Inc.
Securities and Exchange Commission Form 10-K
Consent Letter

Gentlemen:

The firm of Huddleston & Co., Inc. consents to the naming of it as experts and to the incorporation by reference of its report letter dated February 4, 2004 concerning the proved reserves as of December 31, 2003 attributable to Energy Resource Technology, Inc. in the Annual Report of Cal Dive International, Inc. on Form 10-K to be filed with the Securities and Exchange Commission.

Huddleston & Co., Inc. has no interests in Cal Dive International, Inc. or in any of its affiliated companies or subsidiaries and is not to receive any such interest as payment for such report and has no director, officer, or employee employed or otherwise connected with Cal Dive International, Inc. We are not employed by Cal Dive International, Inc. on a contingent basis.

Very truly yours,

HUDDLESTON & CO., INC.

By: /s/ PETER D. HUDDLESTON
Peter D. Huddleston, P.E.
President

EXHIBIT 31.1

SECTION 302 CERTIFICATION

I, Owen Kratz, the Principal Executive Officer of Cal Dive International, Inc., certify that:

1. I have reviewed this Annual Report on Form 10-K of Cal Dive International, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) [Paragraph omitted in accordance with SEC transition instructions contained in SEC Release 34-47986];

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors:

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls.

Date: March 12, 2004

/s/ OWEN KRATZ
Owen Kratz
Chairman and Chief Executive Officer

EXHIBIT 31.2

SECTION 302 CERTIFICATION

I, A. Wade Pursell, the Principal Financial Officer of Cal Dive International, Inc., certify that:

1. I have reviewed this Annual Report on Form 10-K of Cal Dive International, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) [Paragraph omitted in accordance with SEC transition instructions contained in SEC Release 34-47986];

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors:

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls.

Date: March 12, 2004

/s/ A. WADE PURSELL
A. Wade Pursell
Senior Vice President and Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. Section 1350,
AS ADOPTED PURSUANT TO
Section 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report of Cal Dive International, Inc. ("CDIS") on Form 10-K for the period ended December 31, 2003, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Owen Kratz, Chairman and Chief Executive Officer of CDIS, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) the Report fully complies with the requirements of section 13(a) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of CDIS.

Date: March 12, 2004

/s/ OWEN KRATZ
Owen Kratz
Chairman and Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to Cal Dive International, Inc. and will be retained by Cal Dive International, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. Section 1350,
AS ADOPTED PURSUANT TO
Section 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the accompanying Annual Report of Cal Dive International, Inc. ("CDIS") on Form 10-K for the period ended December 31, 2003, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, A. Wade Pursell, Senior Vice President and Chief Financial Officer of CDIS, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) the Report fully complies with the requirements of section 13(a) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of CDIS.

Date: March 12, 2004

/s/ A. WADE PURSELL
A. Wade Pursell
Senior Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Cal Dive International, Inc. and will be retained by Cal Dive International, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.