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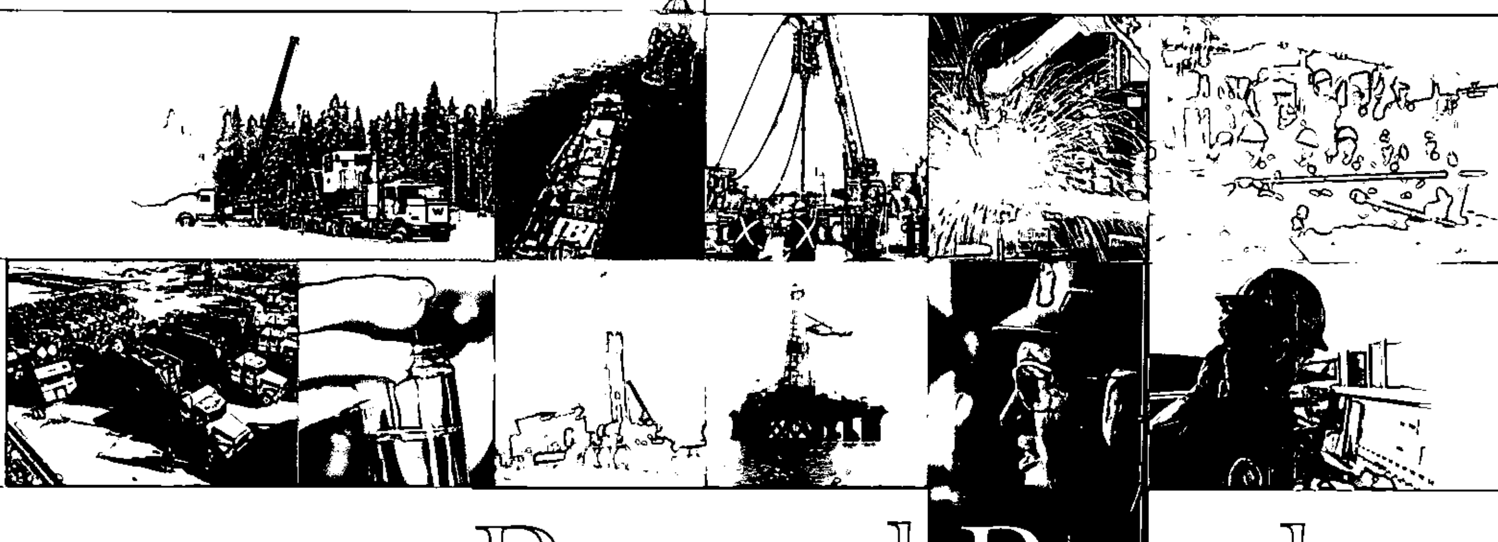
Great Year



Record Results

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operating regions contributed to these outstanding results. Our business in Mexico was down compared to last year, consistent with the reduced activity levels. Reflective of the continued activity growth in Canada, our revenue improved 38% for the year and operating income improved 75%. These were record results as well. Outside North America, our international pressure pumping service operations achieved 28% revenue growth and 78% increase in operating income. Operating income margins improved 440 basis points from the prior year. The Europe & Africa, Middle East, Asia Pacific and Latin America Regions achieved revenue growth in the range of 30% with significant operating income improvement in each of these regions. Improving margins from our international pressure pumping operations has been a focus for the Company and we are beginning to realize the fruits of that effort.

Oilfield Service Group

The Oilfield Service Group consisting of Chemical Services, Casing and Tubular Services, Completion Fluids, Completion Tools and Process and Pipeline Services had an exceptionally good year. Revenue for the group was up 25% and operating income improved by 96%. Each of the service lines experienced double-digit revenue growth with Chemical Services and Completion Fluids achieving greater than 30% revenue growth. Chemical Services and Completion Fluids also led the group with significant operating income improvement. With revenue of $648 million for the year, the group is making a material contribution to the Company's financial results.

Business Highlights

Acquisitions - Although not large transactions, the Company did make two important acquisitions during the year. During the fourth fiscal quarter, the Company completed the purchase of Dyna-Coil, a capillary string installation and production chemical company with most of its operations in the U.S. Dyna-Coil installs small diameter capillary strings through production tubing to the well perforations. Through the capillary string, the well can be effectively treated with specialty production chemicals to address a number of well conditions such as corrosion, paraffin, scale and other conditions and thereby enhance production of oil and gas. Another key technology included with the acquisition is InjectSafe, a patented retrievable downhole tool that allows the capillary strings to be used on wells offshore without compromising the integrity of the subsurface safety valve. This tool is key to the use of capillary string systems offshore. We expect the Dyna-Coil business lines to provide good growth potential in the US and international markets.

The Company also acquired majority interest in its joint venture with ENSP in Algeria, which provides pressure pumping services in that market. Previously, the Company owned a 49% interest in the joint venture. Although the joint venture had grown since its creation in the 1980's, majority ownership allows the Company to elevate the operating standards and to more rapidly grow the business by adding additional BJ service lines not currently provided by BJ in the Algerian market. Our objective is to double revenue within a four-year period.

Expansions - Recent geographic expansion began to contribute to the Company's results during the year. The expansion in Libya produced incremental revenue from our Tubular Service operations and from our pressure pumping operations during the year. The operation was marginally profitable for the year, however significant revenue improvement and respectable profit generation is planned for the second year of operation. So, we are getting off to a good start in this new country expansion.

Two district expansions (Drumheller and Hinton) and significant step up in equipment additions to our Canadian operations helped to fuel the over 38% growth in our Canadian pressure pumping revenue for the year. The strategic location of the new districts and the equipment additions coupled with an increase in higher margin revenue allowed the Company to generate significant revenue growth and contributed to the generation of positive operating margins during the spring break-up period when activity falls off significantly due to weather conditions.

Organic growth through geographic expansion has become an important contributing strategy for the Company. During the past ten years, our International pressure pumping operations have undertaken expansion into 16 new countries that in FY 2006 produced over $143 million in revenue (16% of International pressure pumping revenue) producing 21% of International pressure pumping operating income.

Technology – As the Company has grown over the years, it has continued to increase its investment in research and engineering. Innovative products, services and well problem solutions have been the results of this investment. The challenges our engineers and scientists confront in their quest to provide the best products and solutions for our customers are the various well conditions including high temperature, low temperature, fragile formations, high pressure, low pressure, shallow water flow and many others. They are also challenged by regulations and our desire to protect and prevent damage to the environment with the products we use. The focus of our technology development has been directed to i) Mature Field Production Enhancement, ii) Unconventional Reservoir Development, iii) Harsh Environmental Well Construction and Completion and iv) Production and Completion of Multi-Zones in Single Wellbores. Innovative products brought to the market by the Company during the year to address the needs of our customers include Max Lite 1300, an ultra light weight cement system for rapid compressive strength for low temperature applications; An ultra high temperature cement retarder tested to 575°F used at true vertical depths greater than 30,000 feet on a project in the Gulf of Mexico; A PLONOR defoamer for our cement service line making the Company's cement additives the most ecologically advanced in the industry; Quadra Frac, a low pH, low polymer fracturing fluid designed for use with CO_2; Super Rheo Gel LP, a low phosphate fracturing fluid designed to meet the refining regulations in the Canadian market; Brine Star, a heavy weight brine based fracturing fluid specially developed for a major customer to lower the fracturing treating pressure at the wellhead; MST Gravel Pack Tool, a multi zone single trip gravel pack tool which provides producing zone isolation and selective production; and a stabberless pipe manipulation system used for running casing without a stabber which improves the casing running time and reduces safety risks. These products are a few of many developed by our engineers to address our customer needs and provide the Company a competitive advantage.

Manufacturing – With pressure pumping capacity utilization extremely high in North America and improving in the International markets, the fuel for organic growth in our business is additional plant and operating equipment. The plan for the year was to build $490 million in additional plant and equipment. To achieve this objective, certain parts and components for our equipment had to be ordered nine months to a year in advance due to long delivery times. Since the planned level of spending was significantly greater than the prior year, we specialized our manufacturing locations to drive greater manufacturing efficiency at our five manufacturing locations in Houston, Calgary, Singapore, Dubai and Argentina. By the end of the year, we were able to produce $460 million in new plant and equipment, 42% greater than the prior year – a great achievement for our manufacturing personnel throughout the world.

Market Outlook

The world economies are expected to continue their growth trend, albeit at a somewhat muted pace compared to the past two-year period. Crude oil supply seems to be catching up with demand as demand growth has moderated somewhat thus leading to overtures from the OPEC producing countries to modestly cut back on production. In North America, natural gas production levels are just being maintained even with the recent high levels of drilling activity, however demand has been reduced due to the warmer than normal winter weather leading to gas storage levels at a five year high.

Although these events warrant consideration and some degree of concern, our view is that the longer term growth trends will prevail and we have based our year forward financial plan on continued growth in the industry.

J. W. Stewart
Chairman, President and
Chief Executive Officer
December 7, 2006

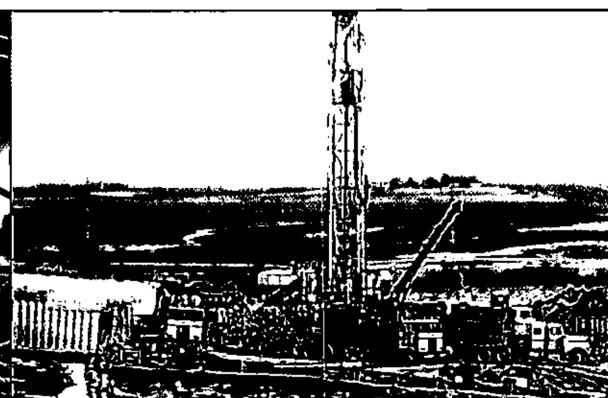
record revenue of $4.4 billion

Record-Setting Operational Achievements

BJ Services Company strengthened its operations to meet increased demand for its services in virtually every oil and gas producing region during 2006. BJ field and support personnel addressed operational challenges, training a growing workforce and increasing service capacity while satisfying customers' requirements. Beyond record-setting financial results discussed in the shareholders' letter, the BJ team reached significant milestones in its work force development, service capabilities and technological innovations.

Work force grows to record level

BJ Services employed more than 16,000 individuals worldwide during 2006. Competition for skilled personnel within our industry sharpened during the year, and BJ increased emphasis on recruiting and training to sustain its growth.



employee training per-capita

...more than 900 classes

new record for annual employee training

BJ Tomball Employee Development Center

maintaining world-class service

BJ region managers employed recruiting tools more frequently to keep pace with customers' increased activity. From participating in more job fairs and making more campus trips to sponsoring outdoor billboards and broadcast advertising, local BJ managers used various hiring strategies to ensure the Company stayed on-track with its work force needs.

The Company expanded its professional recruiting team in Houston to support growth in BJ operations in the U.S. and around the world. In Aberdeen, our long-term participation in a petroleum industry apprentice-mentoring program helped attract qualified and motivated technicians for vital support roles in our Europe-Africa region.

Record levels of personnel training

The Company set a new record for annual employee training per-capita during 2006. This was achieved with expanded course schedules at the BJ Tomball Employee Development Center (TEDC) outside Houston and at BJ regional training centers in Latin America, Asia and Europe, and with record district-level training worldwide.

The in-depth training required to perform BJ's specialized services is not offered in technical schools and universities. To satisfy its work force development requirements, the Company has developed "BJ Services University," a global training system that combines centralized classroom instruction, train-the-trainer programs that distribute instructional material to BJ districts, and on-line distance learning initiatives.

Several thousand BJ employees received formal training through these capabilities in 2006. This included hundreds of BJ engineers around the world who collectively completed more than 900 T-CAP (Technical Career Advancement Program) classes. The Company used its computer network assets for training, delivering more than 5,500 e-Learning classes to employees, more than doubling the level from 2005.

Career Advancement Programs or CAPs represent the heart of BJ's training. The Company offers CAP courses for its engineers and technicians, equipment health, safety, and environment remains a top priority

operators, mechanics, service supervisors, sales personnel and other functional roles, and our CAP programs continue to grow in scope. Increasing the number of qualified BJ service supervisors is essential to fielding more crews to support our customers. An accelerated development program for service supervisors was established in 2006, concurrently training personnel in the U.S., Argentina and Singapore. The Company also expanded classes for developing district safety and training supervisors, a move that strengthens local training capabilities for BJ field personnel worldwide.

We also opened our Sales Management and Leadership Training Center, an expansion of the TEDC campus, during 2006. In addition to supporting training for sales personnel and business managers, this BJ University branch offers advanced training to engineers and technical personnel who seek broader skills and opportunities for advancement.

Milestones in safety performance

Safeguarding health, safety and environmental standards remains a top priority for the entire BJ Services organization and our achievements in this area were recognized during 2006. BJ personnel in the UK were honored with the Scottish Offshore Achievement Award for safety in their North Sea operations. Crews aboard BJ stimulation vessels working offshore Brazil passed a significant milestone -- more than 1,000 days without injury. Personnel at the BJ base in Dongying, China, surpassed that by working more than 3,000 days without a lost-time injury (LTI), and BJ district personnel in Snyder, Texas, passed the 10-year mark without an LTI.

Working safely is essential in oilfield operations, and safe behavior becomes more important as new personnel enter the industry, and BJ district managers instill a safety-conscious culture throughout our operations. The Company emphasizes behavior-based safety training and during 2006 it formally adopted

...adopted a "stop work" policy worldwide.

9 million scf of gas for more than 30 days

a "stop work" policy worldwide. This policy empowers any BJ employee to stop work whenever unsafe conditions are encountered.

Our overall safety performance trends reflect tremendous improvements. The LTI rate in our US/Mexico operations since 1990, our only division for which data is available over that 16-year time frame, has declined from 3.5 to just 0.33 per 200,000 man-hours. During the last five years, our global LTI rate has been reduced more than 60%, from 1.0 to less than 0.4 per 200,000 man-hours.

Unconventional reservoirs drive technical performance

BJ Services attained many service and technology achievements in 2006. A few notable instances illustrate how innovative BJ techniques and products deliver value for BJ customers and shareholders.

In the Barnett Shale region of Texas, horizontal drilling is used with increasing frequency and BJ has adapted its fracturing methodology to help turn wells in these unconventional reservoirs into prolific producers. In one exemplary case, BJ engineers simultaneously fractured two horizontal wells drilled from the same pad. About 60 feet apart on the surface, the wells were separated by as little as 1,000 feet downhole, and fracturing in just one well might adversely affect the other. To avoid this, BJ proposed simultaneous fracturing. One of the first wells stimulated this way produced a daily average 9 million scf of gas for a 30-day period, making it among the most prolific gas wells in the history of the Barnett Shale.

New wells in unconventional "tight gas" formations require fracture stimulation to deliver economic production rates, so increasing interest in tight-gas reserves drives demand for fracturing, the specialized discipline in which BJ Services is a global technology leader. West Texas operators who are exploring the so-called Haley play rely on our capabilities to develop their resources. The BJ Gorilla, a 3,000 horse-power frac pump, has helped the Company capture share in this vibrant market because BJ can deploy more high-pressure pumping horsepower

...most prolific gas wells in the history of the Barnett Shale largest volume pumped

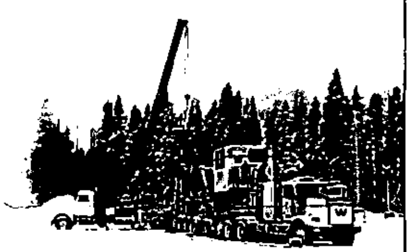
with fewer vehicles. BJ has been expanding its fleets of these units, the highest horse-power frac pumps in the world, for several years.

BJ districts use efficient logistics to accomplish more work in less time. Pad drilling in sensitive environments allows a number of wells to be drilled (and fractured) from a single location. For BJ, pad-fracs offer a way to stimulate more wells from a smaller work site (less environmental impact), with less equipment, simplified operations, a single trip to the site (less travel time) and fewer personnel. BJ Rocky Mountain crews set a record by sequentially fracturing nine wells from one pad, and a trend toward these larger pad-fracs is emerging in select markets.

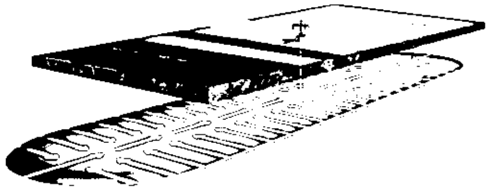
Succeeding in harsh drilling environments

Ultra-deep wells present higher bottom-hole temperatures and higher reservoir pressures that complicate well cementing and stimulation treatments. During 2006, BJ crews successfully managed some of the most demanding temperature and pressure conditions the industry has ever faced.

In the Gulf of Mexico, one of the world's deepest wells -- 30,000+ ft (true vertical depth) -- produced several industry records for casing size and setting depths. Performance records for BJ included the largest volume of BJ Liquid Stone™ cement pumped, highest cement test pressure encountered, deepest use of BJ WellTemp™ thermal simulation software, and the first use of BJ's 600°F-capable high-temperature cement retarder.



...28,000 foot riser and well bore



new technology can spur new applications.

BJ Services marked another well cementing achievement in the giant Azeri-Chirag-Guneshli oil field in the Caspian Sea. Crews used BJ DeepSet™ foam cement technology to mitigate the effects of pressured shallow water flows that rank among the highest ever experienced in offshore drilling. The first use of foamed cement in the Caspian Sea demonstrated this geohazard, which previously hindered development efforts, could now be managed.

Our completion services personnel achieved excellent results in two Gulf of Mexico Green Canyon wells located in 4,500 feet of water. In an industry first, BJ experts developed a special weighted fluid to displace synthetic oil-based mud from the 28,000-ft riser and well bore. Carefully pumping and filtering 15,000 barrels of mud and fluids with minimal rig-time, the BJ team reclaimed all but 35 barrels of mixed interface – an operational and environmental success.

Elsewhere in the Gulf of Mexico, another BJ team successfully restored flow in a deepwater pipeline plugged with paraffin deposits that had thwarted earlier attempts at removal. Crews successfully jetted the line with custom-formulated chemical dispersant (after disconnecting and lifting the subsea line to surface). Selecting the proper dispersant was the critical step, but the deepwater environment added a degree of difficulty.

BJ technologies create new opportunities

Patented BJ LiteProp™ ultra-lightweight proppants for fracturing offer an example of how new technology can spur new applications. In 2006, BJ experts employed these strong, low-density particles for sand control in extended-reach horizontal wells offshore. Used in a well-known technique called gravel packing, these LitePack℠ services provide more competent sheaths around sand screens, especially in long horizontal intervals where conventional materials often cannot be transported.

Among other new BJ technical developments, two provide increasing near-term returns for operators and BJ alike. Our StimTunnel℠ services use coiled tubing and acid jetting to create lateral tunnels away from the main well bore, significantly increasing exposure to producing zones for open-hole wells in carbonate reservoirs. First used in 2006 in Latin America, this technique delivered dramatic production increases from marginal wells. BJ also began adding its specialized production chemicals to frac fluids to prevent or mitigate post-frac production constraints due to scale or bacterial contaminants. StimPlus℠ services differentiate the Company from its competitors because BJ is the only major pumping-services

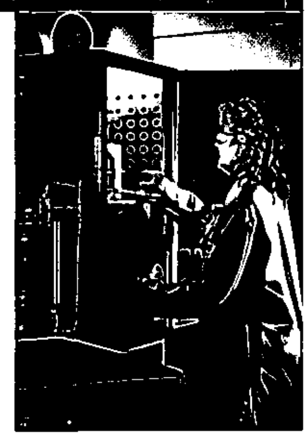
restoring plugged pipelines

supplier with integrated production chemical capabilities.

By virtually all measures, fiscal 2006 was a great year for BJ Services. Against a background of swelling activity and increased investment, our personnel deserve credit for continually improving work processes, advancing technologies and enhancing customer relationships.

our personnel deserve credit...

fiscal 2006 was a great year



Corporate Officers

Company Officers

(Front row, L-R) Kenneth A. Williams, Vice President and President, US/Mexico Division; J.W. Stewart, Chairman, President and Chief Executive Officer; and Margaret B. Shannon, Vice President, General Counsel and Corporate Secretary. (Second row) Susan E. Douget, Director, Human Resources; Paul F. Yust, Chief Information Officer; and Bret Wells, Treasurer and Chief Tax Officer. (Third row) Dave D. Dunlap, Vice President and President, International Division, and Alasdair I. Buchanan, Vice President, Technology. (Back row) Jeffrey E. Smith, Vice President, Finance and Chief Financial Officer, and Brian T. McCole, Controller.

Board of Directors

L. William Heiligbrodt*#
Former President and Chief Operating Officer of Service Corporation International

John R. Huff*†
Chairman and Chief Executive Officer of Oceaneering International, Inc.

Don D. Jordan*†
Retired Chairman and Chief Executive Officer of Reliant Energy, Inc.

Michael E. Patrick*†
Vice President and Chief Investment Officer of The Meadows Foundation Inc.

James L. Payne*#
Chairman and Chief Executive Officer of Shona Energy

J.W. Stewart
Chairman, President and Chief Executive Officer

William H. White†#
Mayor, City of Houston

* Member of Executive Compensation Committee

† Member of Audit Committee

Member of Nominating and Governance Committee

Corporate Information

Transfer Agent and Registrar:
Shareholder questions can be answered by contacting the Company's Transfer Agent.

The Bank of New York
1-800-524-4458

E-Mail Address:
Shareowners@bankofny.com

Address Shareholder Inquiries To:
Shareholder Relations Department - 11E
P. O. Box 11258
Church Street Station
New York, NY 10286

Send Certificates For Transfer and Address Changes To:
Receive and Deliver Department - 11W
P. O. Box 11002
Church Street Station
New York, NY 10286
Answers to many of your shareholder questions and requests for forms are available by visiting The Bank of New York's Website at:
http://www.stockbny.com

Stock Exchange Listings:
New York Stock Exchange
Chicago Board Options Exchange
Ticker Symbol "BJS" (Common Stock)

Independent Auditors:
Deloitte & Touche LLP
Houston, Texas

Form 10-K:
A copy of the Company's Annual Report to the Securities and Exchange Commission (Form 10-K) is available by writing to:
Investor Relations
BJ Services Company
P. O. Box 4442
Houston, Texas 77210-4442
Visit our Website: www.bjservices.com

Annual Meeting:
The Company's Annual Meeting of Stockholders will be held at 11:00 a.m. on January 30, 2007
at The Westin Galleria Hotel
5060 West Alabama, Houston, Texas 77056
(713) 960-8100

The Company's corporate governance guidelines, the charters of the Nominating, Audit, and Executive Compensation Committees of the Board of Directors of the Company, and the Company's Supplemental Code of Ethics for Directors and Officers are available on the Company's website. This information is available in print to any shareholder who requests it. The information is also filed as exhibits and incorporated by reference in the Company's Report on Form 10-K for the fiscal year ended September 30, 2006.

On February 24, 2006 our CEO provided his annual certification to the NYSE that he was not aware of any violation by the company of NYSE's corporate governance listing standards. In addition, our CEO and CFO have made the certifications required under Section 302 of the Sarbanes Oxley Act, which have been filed with our annual report on Form 10-K.

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

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended September 30, 2006

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition Period From to .

Commission file number 1-10570

BJ SERVICES COMPANY
(Exact name of registrant as specified in its charter)

Delaware	**63-0084140**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

4601 Westway Park Blvd, Houston, Texas 77041
(Address of principal executive offices)

Registrant's telephone number, including area code: (713) 462-4239

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

Title of each class	Name of each exchange on which registered
Common Stock $.10 par value per share	New York Stock Exchange
Preferred Share Purchase Rights	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ☑ NO ☐.

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. YES ☐ NO ☑.

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

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

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

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). YES ☐ NO ☑

At November 30, 2006, the registrant had outstanding 293,150,274 shares of Common Stock, $.10 par value per share. The aggregate market value of the Common Stock on March 31, 2006 (based on the closing prices in the daily composite list for transactions on the New York Stock Exchange) held by nonaffiliates of the registrant was approximately $11.1 billion.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the registrant's Proxy Statement for the Annual Meeting of Stockholders to be held January 30, 2007 are incorporated by reference into Part II and Part III of this Form 10-K.

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PART I

ITEM 1. Business

General

BJ Services Company (the "Company"), whose operations trace back to the Byron Jackson Company (founded in 1872), was organized in 1990 under the corporate laws of the state of Delaware. We are a leading worldwide provider of pressure pumping and oilfield services for the petroleum industry. Pressure pumping services consist of cementing and stimulation services used in the completion of new oil and natural gas wells and in remedial work on existing wells, both onshore and offshore. Oilfield services include completion tools, completion fluids, casing and tubular services, production chemical services, and precommissioning, maintenance and turnaround services in the pipeline and process business, including pipeline inspection.

During the year ended September 30, 2006, we generated approximately 85% of our revenue from pressure pumping services and 15% from the oilfield services group. Over the same period, we generated approximately 60% of our revenue from United States operations and 40% from international operations. For segment and geographic information for each of the three years ended September 30, 2006, see Note 8 of the Notes to the Consolidated Financial Statements.

We conduct our operations through four principal segments:

- **U.S./Mexico Pressure Pumping Services.** This segment includes pressure pumping services derived from our activities in the United States and Mexico.
- **International Pressure Pumping Services.** This segment includes pressure pumping services derived from our activities outside of the U.S., Mexico and Canada.
- **Canada Pressure Pumping Services.** This segment includes pressure pumping services derived from our activities in Canada.
- **Oilfield Services Group.** This segment includes the following oilfield service divisions: casing and tubular services, process and pipeline services, production chemical services, completion tools, and completion fluids.

Pressure Pumping Services

Our pressure pumping services consist of cementing services and stimulation services. Stimulation services includes fracturing, acidizing, sand control, nitrogen services, coiled tubing, and service tools. We provide pressure pumping services to major and independent oil and natural gas producing companies, as well as national oil companies. Pressure pumping services are used to complete new oil and natural gas wells, maintain existing oil and natural gas wells, and enhance the production of oil and natural gas from producing formations in reservoirs. These services are provided both on land and offshore on a 24-hour, on-call basis through regional and district facilities in approximately 200 locations worldwide.

Cementing Services

Our cementing services, which accounted for approximately 29% of total pressure pumping revenue during fiscal 2006, consist of blending high-grade cement and water with various solid and liquid additives to create a "cement slurry" that is pumped into a well between the casing and the wellbore. The cement slurry is designed to achieve the proper cement set-up time, compressive strength and fluid loss control. The slurry can be modified to address different well depths, downhole temperatures and pressures, and formation characteristics.

We provide central, regional and district laboratory testing services to evaluate cement slurry properties, which can vary by cement supplier and local water sources. Our field engineers develop job design recommendations to achieve desired compressive strength and bonding characteristics.

The principal application for cementing services used in oilfield operations is primary cementing, or cementing between the casing pipe and the wellbore during the drilling and completion phase of a well. Primary cementing is performed to (i) isolate fluids behind the casing between productive formations and other formations that would damage the productivity of hydrocarbon producing zones or damage the quality of freshwater aquifers, (ii) seal the casing from corrosive formation fluids, and (iii) provide structural support for the casing string. Cementing services are also utilized when recompleting wells from one producing zone to another and when plugging and abandoning wells.

Stimulation Services

Our stimulation services, which accounted for approximately 69% of total pressure pumping revenue during fiscal 2006, consist of fracturing, acidizing, sand control, nitrogen services, coiled tubing and service tools. Stimulation services are provided both onshore and offshore. Offshore services are provided through the use of skid-mounted pumping units and the operation of several stimulation vessels.

We believe that as oil and natural gas production continues to decline in key producing fields in the U.S. and certain international regions and as the development of unconventional hydrocarbon reservoirs increases, the demand for fracturing and other stimulation services is likely to increase. Fracturing is a critical element involved in the successful completion of unconventional reservoirs including "tight" or low permeability sandstones, coal-bed methane and gas bearing shale. Consequently, we have been increasing our pressure pumping capabilities in the U.S. and internationally over the past several years. Stimulation services, which are designed to improve the flow of oil and natural gas from producing formations, are summarized below.

Fracturing. Fracturing services are performed to enhance the production of oil and natural gas from formations having such permeability that the natural flow is restricted. The fracturing process consists of pumping a fluid ("fracturing fluid") into a cased well at sufficient pressure to fracture the producing formation. Sand, bauxite or synthetic proppants are suspended in the fracturing fluid and are pumped into the fracture to prop the fracture open. In some cases, fracturing is performed using an acid solution pumped under pressure without a proppant or with small amounts of proppant. The main components in the equipment used in the fracturing process are a blender, which blends the proppant and chemicals into the fracturing fluid, multiple pumping units capable of pumping significant volumes at high pressures, and a monitoring van equipped with real-time monitoring equipment and computers used to control the fracturing process. Our fracturing units are capable of pumping slurries at pressures of up to 20,000 pounds per square inch.

An important element of fracturing services is the design of the fracturing treatment, which includes determining the proper fracturing fluid, proppants and injection program to maximize results. Our field engineering staff provides technical evaluation and job design recommendations for the customer as an integral element of its fracturing service. Technological developments in the industry over the past several years have focused on proppant concentration control (i.e., proppant density), liquid gel concentrate capabilities, computer design and monitoring of jobs and cleanup properties for fracturing fluids. We have introduced equipment and products to respond to these technological advances.

In 1998, we embarked on a program to replace our aging U.S. fracturing pump fleet with new, more efficient and higher horsepower pressure pumping equipment. We have made significant progress adding new equipment; however much of the older equipment still remains in operation due to the increases in market activity in the U.S. During fiscal 2004, we expanded this U.S. fleet recapitalization initiative to include additional equipment, such as cementing, nitrogen and acidizing equipment. In fiscal 2005, we began recapitalization of our pressure pumping equipment in Canada. Similar to the U.S., much of the older equipment still remains in operation due to the increases in market activity in Canada.

Acidizing. Acidizing enhances the flow rate of oil and natural gas from wells that experience reduced flow caused by formation damage from drilling or completion fluids or the gradual build-up of materials that restrict the flow of hydrocarbons in the formation. Acidizing entails pumping large volumes of specially formulated acids into reservoirs to dissolve barriers and enlarge crevices in the formation, thereby eliminating obstacles to the flow of oil and natural gas. We maintain a fleet of mobile acid transport and pumping units to provide acidizing services for the onshore market and maintain acid storage and pumping equipment on most of our offshore stimulation vessels.

Sand Control. Sand control services involve pumping gravel to fill the cavity created around a wellbore during drilling. The gravel provides a filter for the exclusion of formation sand from the producing wellbore. Oil and natural gas are then free to move through the gravel into the wellbore. These services are performed primarily in unconsolidated sandstone reservoirs, mostly in the Gulf of Mexico, the North Sea, Venezuela, Brazil, Trinidad, West Africa, China, Indonesia and India. Our completion tools, as described later, are often utilized in conjunction with sand control services.

Nitrogen. Nitrogen services involve the use of nitrogen, an inert gas, in various pressure pumping operations. When provided as a stand-alone service, the use of nitrogen is effective in displacing fluids in various oilfield applications, including underbalanced drilling. However, nitrogen is principally used in applications supporting our coiled tubing and stimulation services.

Coiled Tubing. Coiled tubing services involve injecting coiled tubing into wells to perform various well-servicing operations. The application of coiled tubing has increased in recent years due to improvements in coiled tubing technology. Coiled tubing is a flexible steel pipe with a diameter of less than five inches manufactured in continuous lengths of thousands of feet and is wound or coiled on a truck-mounted reel for onshore applications or skid-mounted for offshore applications. Due to the small diameter of coiled tubing, it can be inserted into existing production tubing and used to perform a variety of services to enhance the flow of oil or natural gas without using a larger, costlier workover rig. The principal advantages of employing coiled tubing in a workover include (i) not having to cease production from the well ("shut-in"), thus reducing the risk of formation damage to the well, (ii) being able to move continuous coiled tubing in and out of a well significantly faster than conventional pipe, which must be jointed and unjointed, (iii) having the ability to direct fluids into a wellbore with more precision, allowing for localized stimulation treatments, (iv) providing a source of energy to power a downhole motor or manipulate downhole tools and (v) enhancing access to remote or offshore fields due to the smaller size and mobility of a coiled tubing unit. We have developed a line of specialty downhole tools that may be attached to coiled tubing, including rotary jetting equipment and through-tubing inflatable packer systems.

Service Tools. We provide service tools and technical personnel for well servicing applications in select markets throughout the world. Service tools, which are used to perform a wide range of downhole operations to maintain or improve production in a well, generally are rented from us. While marketed separately, service tools are usually provided during the course of providing other pressure pumping services.

Oilfield Services Group

Our oilfield services group accounted for approximately 15% of our total revenue in fiscal 2006. This segment consists of casing and tubular services, process and pipeline services, production chemicals, completion tools and completion fluids services in the U.S. and select markets internationally.

Casing and Tubular Services

Casing and tubular services comprise installing or "running" casing and production tubing into a wellbore. Casing is run to protect the structural integrity of a wellbore and to isolate various zones in a well. These services are provided primarily during the drilling and completion phases of a well. Production tubing is run inside the casing and oil and natural gas are produced through the tubing. These services are provided during the completion and workover phases of a well. Our casing and tubular services business also provides pipe driving hammer services. Hydraulic and diesel powered hammers are used in a variety of offshore well construction projects. Our casing and tubular services business has historically been focused in the North Sea and selected international markets. The fiscal 2004 acquisitions of Cajun Tubular Services, Inc. and Petro-Drive, a division of Grant Prideco, Inc., expanded our business into the Gulf of Mexico and other international markets.

Process and Pipeline Services

We provide a wide range of services to the process industry, which includes oil and natural gas production, refineries, and gas and petrochemical plants, and to the power industry. These services cover two main areas: (i) the precommissioning of new plants and (ii) maintenance to existing plants. The primary services offered are testing, cleaning, drying and inerting pipework and pipelines. Nitrogen/helium leak testing is used to locate and quantify small leaks on hydrocarbon systems. Leak testing is used on both new and old facilities to minimize the risk of hydrocarbon leaks, improving safety and minimizing greenhouse gas emissions. Systems can be cleaned by flushing, jetting, pigging or chemically treating to ensure debris is removed from the system prior to start-up, thus minimizing damage to expensive process equipment.

Our pipeline services consist of precommissioning and maintenance services. Due to regulatory requirements or safety concerns, new pipelines are often tested prior to their initial use. Pipeline testing typically involves filling the pipeline with water under operating pressures and drying the pipelines. Pipeline drying is carried out using dry air, nitrogen, or a vacuum. Many pipelines require cleaning while "on line" to help ensure the integrity of the pipeline and to maximize product throughput. We offer several techniques for pipeline cleaning. This includes gel cleaning, which is used to carry large amounts of debris out of the pipeline, and various solvent treatments to remove debris.

Our pipeline inspection business uses "intelligent pigs" to assist pipeline operators in assessing the integrity of their pipelines. Pigs are mechanical devices that are propelled through a pipeline. We have also developed two principal pipeline inspection tools: one tool monitors metal loss from the interior pipe wall caused by either corrosion or mechanical damage, and a second tool monitors pipeline geometry (dents, buckles and wrinkles) and position (latitude, longitude, and height) using an inertial guidance system which allows the production of as-built maps of the pipeline as well as the calculation of critical strains due to pipeline movement. Using the information collected by these tools, pipeline operators are able to prepare structural analysis to determine if the pipeline is fit for its purpose.

Production Chemical Services

Production chemical services are provided to customers in the upstream and downstream oil and natural gas businesses. These services involve the design of treatments and the sale of products to optimize production, unload wellbore fluids and reduce the negative effects of corrosion, scale, paraffin, bacteria, and other contaminants in the production and processing of oil and natural gas. Customers engaged in crude oil production, natural gas processing, raw and finished oil and natural gas product transportation, refinery operations and petrochemical manufacturing use these products and services. Production chemical and injection services operations address four principal priorities our customers have: (1) the protection of the customer's capital investment in metal goods, such as downhole casing and tubing, pipelines and process vessels, (2) deliquification of wellbore fluids providing steady state flow and enhanced production, (3) the treatment of fluids to allow the customers to meet the specifications of the particular operation, such as production transferred to a pipeline or fuel sold at a marketing terminal, and (4) injection of production chemicals directly to the desired producing zone through the use of small diameter capillary strings.

Completion Tools

We design, build and install downhole completion tools that utilize gravel and sand control screens to control the migration of reservoir sand into the well and direct the flow of oil and natural gas into the production tubing. We have a specialty tool manufacturing plant in Houston, Texas that manufactures many of the components required in the completion tools, however some components are manufactured by third parties. In addition, spare parts for completion tools and production packers are sold to customers that have purchased tools in the past.

Our completion tools are sold as complete systems, which are customized based on each well's particular mechanical and reservoir characteristics, such as downhole pressure, wellbore size and formation type. Many wells produce from more than one productive zone simultaneously. Depending on the customer's preference, we have the ability to install tools that can either isolate one producing zone from another or integrate the production from multiple producing zones. Our field specialists, working with the rig crews, deploy completion tools in the well during the completion process.

To further enhance reservoir optimization, we have also developed tools to provide the operator with "intelligent completion" capabilities. These tools allow the operator to selectively control flow from multiple productive zones in the same wellbore from a remote surface site. From time to time, we may also outsource the equipment necessary to monitor downhole parameters such as temperature, pressure, and reservoir flow.

In addition to tools that are designed to control sand migration, we also provide completion tools that are generally used in conventional completions for reservoirs that do not require sand control. These tools include non-proprietary production packers and other tools that are delivered through distribution networks located in key domestic markets and select international markets.

In December 2005, we completed the construction of a well screen manufacturing facility in Houston, Texas. Well screens are sections of perforated pipe wrapped with wire that are placed in production tubing and are designed to prevent the flow of gravel into the producing wellbore. These screens are critical to the success of wells in unconsolidated sandstone reservoirs and are integrated into the completion program (sand control, completion tools and well screens). Well screens are utilized primarily in unconsolidated sandstone reservoirs, the majority of which are located in the Gulf of Mexico, the North Sea, Venezuela, Brazil, Trinidad, West Africa, China, Indonesia and India.

Completion Fluids

We sell and reclaim clear completion fluids and perform related fluid maintenance activities, such as filtration and reclamation. Completion fluids are used to control well pressure and facilitate other completion activities while minimizing reservoir damage. We provide basic completion fluids as well as a broad line of specially formulated and customized fluids for critical completion applications.

Completion fluids are available either as pure salt solutions or in combination with other materials. These fluids are solids-free, and therefore, should not restrict the flow of oil and natural gas from the formation. In contrast, drilling mud, the fluid typically used during drilling and in some well completions, contains solids to achieve densities greater than water. These solids can restrict the reservoir, causing reservoir damage and restricting the flow of oil and natural gas into the well. When completion fluids are placed into a well, they typically become contaminated with solids that remain in the well after drilling mud is displaced. To remove these contaminants, we deploy filtering equipment and technicians that work in conjunction with our on-site fluid engineers to maintain the solids-free condition of the completion fluids throughout the project. We provide an entire range of completion fluids, as well as all support services needed to properly apply completion fluids in the field, including filtration, on-site engineering, additives and rental equipment.

Raw Materials and Equipment

Principal materials used in pressure pumping include cement, fracturing proppants, acid, guar polymers, nitrogen, carbon dioxide and other bulk chemical additives. We purchase our principal materials from several suppliers and produce certain materials at our own blending facilities in Germany, Singapore, Canada, the U.S. and Brazil. Sufficient material inventories are generally maintained to allow us to provide on-call services to our pressure pumping customers. We have experienced intermittent tightness in supply for certain types of cement and fracturing proppants but have been able to use alternatives with customer acceptance, and it is not expected to materially hinder operations. In addition, we have entered into agreements to ensure a certain level of materials are maintained in the U.S. and Canada.

Pressure pumping services use complex truck or skid-mounted equipment designed and constructed for the particular pressure pumping service furnished. After equipment is transported to a well location it is configured with appropriate connections to perform the services required. The mobility of this equipment allows us to provide pressure pumping services to wellsites in virtually all geographic areas around the world. Most units are equipped with computerized systems that allow for real-time monitoring and control of the cementing and stimulation processes. In recent months, we have experienced tightness in supply for certain aspects of our pressure pumping equipment, though it is not significantly affecting our current activity levels. We believe our pressure pumping equipment is adequate to service both current and projected levels of market activity in the near term. As the market increases demand for our services, we will continue to add needed capacity in select markets.

Repair parts and maintenance items for pressure pumping equipment are held in inventory at levels that we believe will allow continued operations without significant downtime. We have experienced only intermittent tightness in supply or extended lead times in obtaining necessary supplies of these materials or repair parts. We do not depend on any single source of supply for any of these parts and materials; however, loss of one or more of our suppliers could disrupt operations.

We believe that coiled tubing and other materials used in performing coiled tubing services are and will continue to be widely available from a number of manufacturers. Although there are only two principal manufacturers of the coiled tubing, we have not experienced any difficulty in obtaining coiled tubing in the past and do not anticipate difficulty in the foreseeable future.

Nitrogen is one of the principal materials used in our process and pipeline services division. We purchase nitrogen from several suppliers. We have experienced only intermittent tightness in supply or extended lead times in obtaining nitrogen and do not expect any chronic shortage of nitrogen in the foreseeable future.

Engineering and Support Services

Our research and development department is divided into seven areas: Product Development, Applied Technology, Software Applications, Instrumentation Engineering, Mechanical Engineering, Coiled Tubing Engineering and Completion Tools Engineering.

Product Development

The product development laboratory specializes in developing products with enhanced performance characteristics for fracturing, acidizing, sand control and cementing operations (i.e., fracturing fluid and cement slurry). As fluids must perform under a wide range of downhole pressures, temperatures and other conditions, this laboratory is a critical element in developing products to meet customer needs.

Applied Technology

The Applied Technology Group (ATG) is primarily responsible for supporting technical and engineering applications on a global basis for the six primary service product lines that we offer (acidizing, cementing, completion tools, completion fluids, coiled tubing and fracturing). In addition to providing engineering support, the ATG is responsible for assisting in the internal technology transfer within the Company and developing and maintaining all of the support documentation for our chemical products and systems. The ATG also assists in the management and maintenance of the intellectual property. Another key responsibility of the ATG is to guide and prioritize the technology development based on feedback from operations and direct client interaction.

Software Applications

Our software applications group develops and supports a wide range of proprietary software used to monitor both cement and stimulation job parameters. This software, combined with our internally developed monitoring hardware, allows for real-time job control and post-job analysis.

Instrumentation Engineering

We use an array of monitoring and control instrumentation, which is an integral element of providing cementing and stimulation services. Our monitoring and control instrumentation, developed by our instrumentation engineering group, complements our products and equipment and provides customers with real-time monitoring of critical applications.

Mechanical Engineering

Though similarities exist among the major pressure pumping competitors in the general design of pumping equipment, the actual engine/transmission configurations and the mixing and blending systems differ significantly. Additionally, different approaches to the integrated control systems result in equipment designs, which are usually distinct in performance characteristics for each competitor. Our mechanical engineering group is responsible for the design of virtually all of our primary pumping and blending equipment. Our mechanical engineering group provides new equipment design as well as support to the rebuilding and field maintenance functions.

Coiled Tubing Engineering

The coiled tubing engineering group provides most of the support and research and development activities for our coiled tubing services, including coiled tubing drilling technology. This group is also actively involved in the ongoing development and manufacturing of specialized downhole tools that may be attached to the end of coiled tubing.

Completion Tools Engineering

The completion tools engineering group specializes in the designing, manufacturing and testing of completion tools. Since completion tools are often installed miles below the earth's surface, it is critical that potential design flaws be diagnosed and prevented prior to installation. Optimal tool configuration is determined by considering a variety of factors, including raw materials, operating conditions and design specifications.

Manufacturing

We own two primary manufacturing facilities in the Houston, Texas area. Our research and technology center in Tomball, Texas houses our main equipment and instrumentation manufacturing facility, primarily serving pressure pumping services. Our facility in Houston, Texas produces certain components and spare parts required for the assembly of downhole completion tools, service tools and well screens. We also have several smaller manufacturing facilities internationally to support our worldwide operations. We employ outside vendors for manufacturing various units and for engine and transmission rebuilding and certain fabrication work, but we are not dependent on any one vendor.

Competition

Pressure Pumping Services

There are two primary companies with which we compete in pressure pumping services worldwide, Halliburton Energy Services, a division of Halliburton Company, and Schlumberger Ltd. These companies have operations in most areas in which we operate. Halliburton Energy Services and Schlumberger are larger in terms of overall pressure pumping revenue. It is estimated that these two competitors, along with us, provide approximately 75% of the worldwide pressure pumping services to the industry. Several smaller companies, as well as Weatherford International, Inc., compete with us in certain areas of the U.S. We also have competition from smaller companies internationally such as Calfrac Well Services Ltd., Trican Well Service Ltd. and San Antonio, a division of Pride International. Competitive factors impacting our business are prices, technology, service record and reputation in the industry.

Oilfield Services Group

We believe that we are one of the largest suppliers of casing and tubular services in the North Sea and have expanded these services into other international markets in the past several years. We began offering these services in the U.S. in fiscal 2004 with the acquisition of Cajun Tubular Services, Inc. and Petro-Drive. The largest worldwide provider of casing and tubular services is Weatherford International, Inc. In addition, we compete with Frank's International Inc. in the Gulf of Mexico and certain international markets.

We believe we are the largest provider of precommissioning and leak detection services and one of the largest providers of pipeline inspection services. Our principal competitors in pipeline inspection are Pipeline Integrity International Ltd. (a division of General Electric), Tuboscope (a subsidiary of National Oilwell Varco) and H. Rosen Engineering GmbH.

There are several competitors significantly larger than us in production chemical services.

Our principal competitors in completion fluids are Baroid Corporation, a subsidiary of Halliburton Company; M-I LLC, a joint venture of Smith International, Inc. and Schlumberger Ltd; Baker Hughes, Inc.; and Tetra Technologies, Inc.

Our principal competitors in completion tools are Halliburton Energy Services, a division of Halliburton Company, Schlumberger Ltd, Baker Hughes Inc. and Weatherford International, Inc. Competitive factors impacting our business are prices, technology, service record and reputation in the industry.

Markets and Customers

Demand for our services and products depends primarily upon the number of oil and natural gas wells being drilled ("rig count"), the depth and drilling conditions of such wells, the number of well completions and the level of workover activity worldwide. With the exception of the Canadian spring break-up, we are not significantly impacted by seasonality. Spring break-up is the period during which snow and ice begin to melt and heavy equipment is not permitted on the roads, resulting in lower drilling activity.

Our principal customers consist of major and independent oil and natural gas producing companies, as well as national oil companies. During fiscal 2006, we provided services to several thousand customers, none of which accounted for more than 5% of consolidated revenue. While the loss of certain of our largest customers could have a material adverse effect on our revenue and operating results in the near term, we believe we would be able to obtain other customers for our services in the event of a loss of any of our largest customers.

United States

The United States is the largest single pressure pumping market in the world. We provide pressure pumping services to our U.S. customers through a network of more than 50 locations throughout the U.S., a majority of which offer both cementing and stimulation services. Demand for our pressure pumping services in the U.S. is primarily driven by oil and natural gas drilling activity, which tends to be extremely volatile depending on the current and anticipated prices of oil and natural gas. During the last 10 years, the lowest U.S. rig count averaged 601 in fiscal 1999 and the highest U.S. rig count averaged 1,587 in fiscal 2006, a 20% increase over the fiscal 2005 average U.S. rig count of 1,323. In fiscal 2005, the average U.S. rig count was 15% higher than the fiscal 2004 U.S. rig count average of 1,155.

International

We operate in approximately 50 countries which encompass the major international oil and natural gas producing areas of Latin America, Europe, Africa, Russia, Asia and the Middle East. We generally provide services to international customers through wholly-owned foreign subsidiaries. Additionally, we hold controlling or minority interests in several joint venture companies through which we conduct a portion of our international operations.

Many countries in which we operate are subject to political, social and economic risks which may cause volatility within any given country. However, operating in approximately 50 countries provides some protection against volatility risk of individual countries. Due to the significant investment in and complexity of international projects, management believes drilling decisions relating to such projects tend to be evaluated and monitored with a longer-term perspective with regard to oil and natural gas pricing. Additionally, the international market is dominated by major oil companies and national oil companies which tend to have different objectives and more operating stability than the typical independent producer in North America. During the last 10 years, the lowest international rig count averaged 616 in fiscal 1999 and the highest international rig count averaged 905 in fiscal 2006, a 9% increase over the fiscal 2005 average international rig count of 833. In fiscal 2005, the average international rig count was 9% higher than the fiscal 2004 international rig count average of 767. In January 2004, we completed the commissioning of another stimulation vessel, the "Blue Angel," which is currently under contract and is operating offshore Brazil. We opened offices in Libya during fiscal 2005, and started operations there during fiscal 2006. Since 1986, we have been involved in the pumping services business in Algeria through minority interest participation in a company known as Societe Algerienne de Stimulation de Puits Producteurs d'Hydrocabures (BJSP). In June 2006, we participated in a recapitalization of BJSP which resulted in the Company becoming the majority interest partner and operator of the joint venture. As a result of this transaction, we expect to expand product lines in Algeria, such as hydraulic fracturing, which are not currently part of the joint venture's scope of business. Also in fiscal 2006, operating bases in New Zealand, Uzbekistan and Oman were opened.

We operate in most of the major oil and natural gas producing regions of the world. International operations are subject to risks that can materially affect our sales and profits, including currency exchange rate fluctuations, inflation, governmental expropriation, currency controls, political instability and other risks. The risk of currency exchange rate fluctuations and its impact on net income are mitigated by using natural hedges in which we invoice for work performed in certain countries in both U.S. dollars and local currency. We attempt to match the amounts invoiced in local currency with the amount of expenses denominated in local currency.

Canada

The Canadian market is very similar to the U.S. During the last 10 years, the lowest Canadian rig count averaged 212 in fiscal 1999 and the highest Canadian rig count averaged 502 in fiscal 2006, a 20% increase over the fiscal 2005 average rig count of 420. In fiscal 2005, the average rig count was 15% higher than the fiscal 2004 rig count average of 366.

Our Canadian operations are subject to currency exchange rate fluctuations. The Canadian dollar is the functional currency for this segment. The risk of currency exchange rate fluctuations and its impact on net income are mitigated by using natural hedges in which we invoice for work performed in both U.S. dollars and Canadian dollar. We attempt to match the amounts invoiced in Canadian dollars with the amount of expenses denominated in Canadian dollars. As such, currency exchange rate fluctuations may have a significant impact on our revenues, but we attempt to minimize the impact on operating income by utilizing natural hedges.

Employees

At September 30, 2006, we employed approximately 16,000 personnel around the world. Approximately 61% of our employees were employed outside the United States. As we continue to experience expanding activity levels, we have encountered intermittent labor shortages. As in the past, we have accommodated for these temporary shortages by increasing the number of contract personnel and contract services in order to meet customer requirements.

Governmental and Environmental Regulation

Our business is affected both directly and indirectly by governmental regulations relating to the oil and natural gas industry in general, as well as environmental and safety regulations which have specific application to our business.

Through the routine course of providing services, we handle and store bulk quantities of hazardous materials. If leaks or spills of hazardous materials handled, transported, or stored by us occur, we may be responsible under applicable environmental laws for costs of remediating any damage to the surface or sub-surface (including aquifers). Accordingly, we have implemented and continue to implement various procedures for the handling and disposal of hazardous materials. Such procedures are designed to minimize the occurrence of spills or leaks of these materials. In addition, leak detection services, provided through our process and pipeline division, involve the inspection and testing of facilities for leaks of hazardous or volatile substances.

We have implemented and continue to implement various procedures to further assure our compliance with environmental regulations. Such procedures generally pertain to the operation of underground storage tanks, disposal of empty chemical drums, improvement to acid and wastewater handling facilities, and cleaning certain areas at our facilities. In addition, we maintain insurance for certain environmental liabilities, which we believe is reasonable based on our experience and knowledge of the industry.

The Comprehensive Environmental Response, Compensation and Liability Act, also known as "Superfund," imposes liability without regard to fault or the legality of the original conduct, on certain classes of persons who contributed to the release of a "hazardous substance" into the environment. Certain disposal facilities owned by third parties but used by us or our predecessors have been investigated under state and federal Superfund statutes, and we are currently named as a potentially responsible party for cleanup at four such sites. Although our level of involvement varies at each site, we are one of numerous parties named and will be obligated to pay an allocated share of the cleanup costs. While it is not feasible to predict the outcome of these matters with certainty, we believe that the ultimate resolutions should not have a materially adverse effect on our results of operations or financial position.

Research and Development

Our research and development activities are focused on improving existing products and services and developing new technologies designed to meet industry and customer needs. We currently hold numerous patents of varying remaining duration. Although such patents, in the aggregate, are important to maintaining our competitive position, no single patent is considered to be of a critical or essential nature to our ongoing operations. We also use technologies owned by third parties under various license arrangements, generally ranging from 10 to 20 years in duration, relating to certain products or methods for performing services. None of these license arrangements is material to our overall operations.

We intend to continue to devote significant resources to research and development efforts. For information regarding the amounts of research and development expenses for each of the three fiscal years ended September 30, 2006, see Note 12 of the Notes to the Consolidated Financial Statements.

Pressure Pumping Services

We have a history of developing patented, industry-leading well stimulation technologies such as Spectra Frac G® high-performance fracturing fluid, introduced in 1991, polymer-specific enzyme fluid breakers, first commercialized in the early 1990s, and EZ Clean®, launched in 1993, a polymer-specific enzyme treatment designed to remediate reservoirs that have been damaged by previous fracturing efforts. In 1998, we released Vistar® low-polymer fracturing fluids capable of providing optimum placement of proppant in the reservoir while minimizing fracture damage. During 2003, we introduced LiteProp™ lightweight proppants (patented and patents pending). These low-density proppants produce greater propped fracture length and conductivity than is produced by conventional proppants and may be transported to the formations with lower polymer concentration gels than is required by conventional proppants. During fiscal 2006, we continued to develop lightweight proppants and introduced even lower density materials that allow us to pump proppants without any viscosifiers in the fluid.

Other stimulation technologies include the patented BJ Sandstone Acid™ system, introduced in 1994, which is designed to enhance production in sandstone reservoirs and remove damage accumulated during previous fracturing and work over efforts. This system has now been improved upon in fiscal 2006 to be used as a single stage matrix acid treatment or as an acid fracturing system on its own.

We also developed AquaCon™, a relative permeability modifier, which was patented in 2001. It is a water control system for reducing undesirable water production, while increasing oil or natural gas production. Our patented Liquid Stone® cement slurry is a premixed cement blend which, unlike conventional cement slurries, is storable in its liquid form for weeks or months prior to use. The slurry is premixed, and no on-site mixing equipment is required. It can be pumped through rig pumps.

We have development leading technologies for our coiled tubing services. The patented Tornado™ cleanout system provides an effective method for removing sand and other fill material from wells at much greater efficiencies than previously obtainable. The Roto-Pulse™ gravel pack cleaning system is used in removing material restricting a gravel pack. During 2001 and 2002, we developed the LEGS™ (lateral entry guidance system) tool for use with coiled tubing operations in horizontal wells. The LEGS™ tool provides the technology to locate and successfully guide the coiled tubing into horizontal wells in order to perform coiled tubing workover operations. In 2006, in order to meet the higher quality demands of our customers, we have designed and have introduced a real-time quality control monitoring instrument for our coiled tubing fleets. This instrument, Opti + Cal, will increase the reliability of the pipe we insert into the well.

In 2005, we continued developing and improving the InsulGel™ and Super InsulGel™ families of thermally insulated packer fluids for minimizing heat transfer from produced fluids. These fluids reduce heat loss through either conduction or convection mechanisms, allowing an improvement of heat retention and reducing or eliminating the need for insulating tubing. Proprietary additives to enhance the performance of fracturing and other systems, such as ScaleSorb™ scale control agent to provide immediate and long-term pack protection from scale deposits, continue to be developed and introduced to the market.

We have also made advances in cementing technologies. LOTIS™ (Long-Term Isolation) cement engineering process allows the potential long-term stresses on the well to be analyzed, making it possible to design the correct cement formulation and evaluate the material properties of the set cement to ensure long-term annular isolation. The proprietary IsoVison™ modeling program for calculating the direction and magnitude of induced stress in the cement sheath was also introduced. The IsoVision analysis enables the design of slurry formulations that offer cement properties precisely matched to the varied requirements of offshore and land operations.

In order to meet the needs of the ultra high temperature wells currently being drilled, a range of synthetic cement retarders and free water control additives have been developed which will perform in wells with bottom hole temperatures up to 575 degrees Fahrenheit. These products have been successfully pumped in a recent Gulf of Mexico well.

Oilfield Services Group

We have developed a broad line of completion tool systems for both conventional completions and horizontal well completions in both gravel-packed and conventional configurations. The PAC valve (pressure actuated circulating valve) is a key component enabling interventionless intelligent completion systems. During 2000 and 2001, we successfully field-tested the TST-3™ service tool packer. During 2001 and 2002, we successfully field-tested a composite drillable bridge plug, the Python™, for which patents have been granted and are pending. The Python plug performs at temperatures in excess of 375 degrees Fahrenheit and differential pressures greater than 10,000 pounds per square inch.

During 2006, we expanded our already broad line of completion tool systems to include the InjectSafe ™ sub-surface safety valve system. The InjectSafe wireline surface-controlled sub-surface safety valve system provides the functionality of a wireline-retrievable safety valve with an integral capillary tubing flow path. This allows continuous chemical treatment up to 22,000 feet (6,700 meters) below the safety valve without interruption or risk to the safety valve. Continuous chemical injection below the safety valve can help prevent production problems associated with asphaltenes, paraffin, scale, hydrates, corrosion and liquid loading. The InjectSafe System also eliminates the need for a storm choke by providing control at surface when installed in a tubing-retrievable safety valve for which control line integrity has been compromised.

We also introduced the FlowSafe™ WR wireline-retrievable safety valves and the FlowSafe™ TR tubing-retrievable safety valves. The FlowSafe valves are flapper type, equalizing or non-equalizing, surface-controlled sub-surface safety valves. The valves are designed to provide sub-surface isolation to minimize the loss of production, protect human life, and reduce the potential for environmental discharge or damage to production equipment resulting from an uncontrolled surface or sub-surface event.

The FlowSafe WR valve can be installed to remediate a failed tubing-retrievable safety valve, as a primary safety valve landed in a hydraulic nipple, and as an integral part of the InjectSafe system. The FlowSafe TR valve is hydraulically controlled from the surface through a control line connected to the well control/emergency shut down system. A complete set of remediation tools are available to either lock the valve permanently open or to establish hydraulic communication.

During 2005, we successfully field tested the Multi-Zone Single Trip (MST) tool, which allows the operators to install multiple gravel packs in a well during a single trip. The MST also provides for frac packing each zone individually.

In 2005, we began designing and manufacturing a wide range of screens for soft rock completions in our new state-of-the-art manufacturing facility in Houston, Texas. Standard and heavy-duty wire wrapped screens, standard pre-packed wire wrapped screens, premium screens, and premium diffused bonded laminated screens are manufactured in this facility.

Available Information

Information regarding the Company, including corporate governance policies, ethics policies and charters for the committees of the board of directors can be found on our internet website at *http://www.bjservices.com*. In addition, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are made available free of charge on our internet website on the same day that we electronically file such material with, or furnish it to, the Securities and Exchange Commission ("SEC"). Information filed with the SEC may be read or copied at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Information on operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also maintains an internet website (*http://www.sec.gov*) that contains reports, proxy and information statements, and other information regarding issuers that file electronically.

Executive Officers of the Registrant

Our current executive officers and their positions and ages are as follows:

Name	Age	Position	Office Held Since
J. W. Stewart	62	Chairman of the Board, President and Chief Executive Officer	1990
Alasdair Buchanan	46	Vice President—Technology and Logistics	2005
Susan Douget	46	Director of Human Resources	2003
David Dunlap	45	Vice President and President—International Division	1995
Brian T. McCole	47	Controller	2002
Margaret B. Shannon	57	Vice President—General Counsel	1994
Jeffrey E. Smith	44	Vice President—Finance and Chief Financial Officer	2006
D. Bret Wells	41	Treasurer and Chief Tax Officer	2006
Kenneth A. Williams	56	Vice President and President—U.S./Mexico Division	1991
Paul Yust	53	Chief Information Officer	2006

Mr. Stewart joined Hughes Tool Company in 1969 as Project Engineer. He served as Vice President—Legal and Secretary of Hughes Tool Company and as Vice President—Operations for a predecessor of the Company prior to being named President of the Company in 1986. In 1990, he was also named Chairman and Chief Executive Officer of the Company.

Mr. Buchanan joined the Company in 1982 as a Trainee Engineer and was named Vice President—Technology and Logistics in 2005. He has previously served in numerous international Engineering and Operations positions, including Region Manager of the Europe Africa Region, a position he had held from 1999 through 2005.

Ms. Douget joined the Company in 1979 and was promoted to Director, Human Resources in 2003. Prior to being promoted to Director, she held various positions within the Human Resources function.

Mr. Dunlap joined the Company in 1984 as a District Engineer and was named Vice President—International Division in 1995. He has previously served as Vice President—Sales for the Coastal Division of North America and U.S. Sales and Marketing Manager.

Mr. McCole originally joined the Company as Director of Internal Audit in 1991. He also served as Controller of the Asia Pacific Region and Controller of BJ Chemical Services (formerly BJ Unichem). He left the Company in 1998 and returned in 2001 to serve as Director of Internal Audit until becoming Controller in 2002.

Ms. Shannon joined the Company in 1994 as Vice President—General Counsel from the law firm of Andrews Kurth LLP, where she had been a partner since 1984.

Mr. Smith joined the Company in 1990 as Financial Reporting Manager. He also served as Director, Financial Planning and the Director of Business Development. He held the position of Treasurer from 2002 through 2006 and was named Vice President, Finance and Chief Financial Officer in 2006.

Mr. Wells joined the Company as Tax Director in 2002. Prior to that date, Mr. Wells worked the majority of his career at Cargill, Inc. where he served as Assistant Vice President—Tax. He was named Treasurer and Chief Tax Officer in 2006.

Mr. Williams joined the Company in 1973 and has since held various positions in the U.S. operations. Prior to being named Vice President—U.S. Division in 1991, he served as Region Manager—Western U.S. and Canada.

Mr. Yust joined the Company as Chief Information Officer in 2006. He joined the Company from Kraton Polymers LLC, a multinational chemical manufacturing and distribution company, where he served as the Chief Information Officer from 2001 until 2005.

ITEM 1A. Risk Factors

This document, and our other filings with the Securities and Exchange Commission, and other materials released to the public contain "forward-looking statements," as defined in the Private Securities Litigation Reform Act of 1995. These forward-looking statements may discuss our prospects, expected revenue, expenses and profits, strategies for our operations and other subjects, including conditions in the oilfield service and oil and natural gas industries and in the United States and international economy in general.

Our forward-looking statements are based on assumptions that we believe to be reasonable but that may not prove to be accurate. All of our forward-looking information is, therefore, subject to risks and uncertainties that could cause actual results to differ materially from the results expected. Although it is not possible to identify all factors, these risks and uncertainties include the risk factors discussed below.

Business Risks

Our results of operations could be adversely affected if our business assumptions do not prove to be accurate or if adverse changes occur in our business environment, including the following areas:

- fluctuating prices of crude oil and natural gas,
- conditions in the oil and natural gas industry, including drilling activity,
- reduction in prices or demand for our products and services and level of acceptance of price book increases in our markets,
- general global economic and business conditions,
- international political instability, security conditions, hostilities, and declines in customer activity due to adverse local and regional conditions,
- our ability to expand our products and services (including those we acquire) into new geographic markets,
- our ability to generate technological advances and compete on the basis of advanced technology,
- risks from operating hazards such as fire, explosion, blowouts and oil spills,
- litigation for which insurance and customer agreements do not provide protection,
- adverse consequences that may be found in or result from internal investigations, including potential financial and business consequences and governmental actions, proceedings, charges or penalties,

- changes in currency exchange rates,
- severe weather conditions, including hurricanes, that affect conditions in the oil and natural gas industry,
- the business opportunities that may be presented to and pursued by us,
- competition and consolidation in our business,
- changes in law or regulations and other factors, many of which are beyond our control, and
- other risks and uncertainties detailed from time to time in our filings with the Securities and Exchange Commission.

Risks of Economic Downturn and Lower Oil and Natural Gas Prices

In the event of an economic downturn in the United States or globally, there may be decreased demand and lower prices for oil and natural gas and therefore lower demand for our products and services. Our customers are generally involved in the energy industry, and if these customers experience a business decline, we may be subject to increased exposure to credit risk. If an economic downturn occurs, our results of operations may be adversely affected. A decline in oil and natural gas prices for any reason could reduce demand for our services.

Risks from Operating Hazards

Our operations are subject to hazards present in the oil and natural gas industry, such as fire, explosion, blowouts and oil spills. These incidents as well as accidents or problems in normal operations can cause personal injury or death and damage to property or the environment. The customer's operations can also be interrupted. From time to time, customers seek to recover from us for damage to their equipment or property that occurred while we were performing work. Damage to the customer's property could be extensive if a major problem occurred. For example, operating hazards could arise:

- in the pressure pumping, completion fluids, completion tools and casing and tubular services, during work performed on oil and natural gas wells,
- in the production chemical business, as a result of use of our products in oil and natural gas wells and refineries, and
- in the process and pipeline business, as a result of work performed by us at petrochemical plants as well as on pipelines.

Risks from Unexpected Litigation

We have insurance coverage against some operating hazards. This insurance has deductibles or self-insured retentions and contains certain coverage exclusions. Our insurance premiums can be increased or decreased based on the claims made by us under our insurance policies. The insurance does not cover damages from breach of contract by us or based on alleged fraud or deceptive trade practices. Whenever possible, we obtain agreements from customers that limit our liability. Insurance and customer agreements do not provide complete protection against losses and risks, and our results of operations could be adversely affected by unexpected claims not covered by insurance.

Risks from Ongoing Investigations

In recent government actions, civil and criminal penalties and other sanctions have been imposed against several public corporations and individuals arising from allegations of improper payments and deficiencies in books and records and internal controls. The U.S. Department of Justice, the U.S. Securities and Exchange Commission ("SEC") and other authorities have a broad range of civil and criminal sanctions they may seek to impose in these circumstances, including, but not limited to, injunctive relief, disgorgement, fines, penalties and modifications to business practices and compliance programs. We are in discussions with the Department of

Justice and the SEC regarding our internal investigations and cannot currently predict the outcome of our investigations, when any of these matters will be resolved, or what, if any, actions may be taken by the Department of Justice, the SEC or other authorities or the effect the actions may have on our business or consolidated financial statements.

Risks from International Operations

Our international operations are subject to special risks that can materially affect our sales and profits. These risks include:

- limits on access to international markets,
- unsettled political conditions, war, civil unrest, and hostilities in some petroleum-producing and consuming countries and regions where we operate or seek to operate,
- declines in, or suspension of, activity by our customers in our areas of operations due to adverse local or regional economic, political and other conditions that reduce drilling operations,
- fluctuations and changes in currency exchange rates,
- the impact of inflation,
- the ultimate tax liability may be significantly different due to different interpretations of local tax laws and tax treaties, estimates and assumptions made regarding the scope of and timing of income earned and changes in tax laws,
- governmental action such as expropriation of assets, and changes in general legislative and regulatory environments, currency controls, global trade policies such as trade restrictions and embargoes imposed and international business, political and economic conditions,
- terrorist attacks and threats of attacks have increased the political and economic instability in some of the countries in which we operate, and
- the risk that events or actions taken by us or others as a result of our currently ongoing investigations (see "Management's Discussion and Analysis—Investigations Regarding Misappropriation and Possible Illegal Payments.") adversely affect our operations in the affected countries.

Weather

Our performance is significantly impacted by the demand for natural gas in North America. Warmer than normal winters in North America, among other factors, may adversely impact demand for natural gas and, therefore, demand for our services.

In addition, our U.S. operations could be materially affected by severe weather in the Gulf of Mexico. Severe weather, such as hurricanes, may cause:

- evacuation of personnel and curtailment of services,
- damage to offshore drilling rigs resulting in suspension of operations, and
- loss of or damage to our equipment, inventory, and facilities.

Credit Rating

If our credit rating is downgraded below investment grade, this could increase our costs of obtaining, or make it more difficult to obtain or issue, new debt financing. If our credit rating is downgraded, we could be required to, among other things, pay additional interest under our credit agreements, or provide additional guarantees, collateral, letters of credit or cash for credit support obligations.

Other Risks

Other risk factors that could cause actual results to be different from the results we expect include changes in environmental laws and other governmental regulations.

The market price for our common stock, as well as other companies in the oil and natural gas industry, has been historically volatile.

Many of these risks are beyond our control. In addition, future trends for pricing, margins, revenue and profitability remain difficult to predict in the industries we serve and under current economic and political conditions. Except as required by applicable law, we do not assume any responsibility to update any of our forward-looking statements.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 2. Properties

During fiscal 2006, we completed construction and now own our corporate office in Houston, Texas. Other properties are either owned or leased and typically serve all of our business lines. These properties are located near major oil and natural gas fields to optimally address our customers' needs. Administrative offices and facilities have been built on these properties to support our business through regional and district facilities in approximately 200 locations worldwide, none of which are individually significant due to the mobility of the equipment, as discussed in the "Raw Materials and Equipment" section.

In addition, we own two primary manufacturing facilities in the Houston, Texas area. Our research and technology center in Tomball, Texas houses our main equipment and instrumentation manufacturing operation, primarily serving pressure pumping services. Our facility in Houston, Texas produces certain components and spare parts required for the assembly of downhole completion tools, service tools and well screens. We also have several smaller manufacturing facilities internationally to support our world-wide operations.

Our equipment consists primarily of pressure pumping and blending units and related support equipment such as bulk storage and transport units. Although a portion of our U.S. pressure pumping and blending fleet is being utilized through a servicing agreement with an outside party (see *Lease and Other Long-Term Commitments* in Note 10 of the Notes to the Consolidated Financial Statements), the majority of our worldwide fleet is owned and unencumbered. Our tractor fleet, most of which is owned, is used to transport the pumping and blending units. The majority of our light duty truck fleet, both in the U.S. and international operations, is also owned.

We believe our facilities and equipment are adequate for our current operations, although growth of our business in certain areas may require facility expansion or new facilities. For additional information with respect to our lease commitments, see Note 10 of the Notes to the Consolidated Financial Statements.

ITEM 3. Legal Proceedings

The information regarding litigation and environmental matters described in Note 10 of the Notes to the Consolidated Financial Statements included elsewhere in this Annual Report on Form 10-K is incorporated herein by reference.

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

No matters were submitted for stockholders' vote during the fourth quarter of the fiscal year ended September 30, 2006.

PART II

ITEM 5. Market for Registrant's Common Equity and Related Stockholder Matters

Our common stock began trading on The New York Stock Exchange ("NYSE") in July 1990 under the symbol "BJS". At November 30, 2006, there were approximately 1,398 holders of record of our common stock.

The table below sets forth for the periods indicated the high and low sales prices per share for our common stock reported on the NYSE composite tape. On July 28, 2005 our Board of Directors approved a 2 for 1 stock split which was effected in the form of a stock dividend paid on September 1, 2005 to stockholders of record as of August 18, 2005. All share and share prices have been adjusted to reflect the stock prices on a post-split basis.

	Common Stock Price Range	
	High	Low
Fiscal 2006		
1st Quarter	$39.78	$30.89
2nd Quarter	42.85	30.25
3rd Quarter	41.79	31.81
4th Quarter	38.01	27.87
Fiscal 2005		
1st Quarter	27.00	22.48
2nd Quarter	25.94	21.55
3rd Quarter	27.10	23.74
4th Quarter	36.39	26.48

At September 30, 2006, there were 347,510,648 shares of common stock issued and 293,193,764 shares outstanding. On January 31, 2006, our stockholders approved a charter amendment increasing the authorized number of shares of common stock from 380,000,000 shares to 910,000,000 shares.

We have a Stockholder Rights Plan (the "Rights Plan") designed to deter coercive takeover tactics and to prevent an acquirer from gaining control of the Company without offering a fair price to all of our stockholders. The Rights Plan was amended September 26, 2002, to extend the expiration date of the Rights to September 26, 2012 and increase the purchase price of the Rights. Under this plan, as amended, each outstanding share of common stock includes one-eighth of a preferred share purchase right ("Right") that becomes exercisable under certain circumstances, including when beneficial ownership of common stock by any person, or group, equals or exceeds 15% of our outstanding common stock. Each Right entitles the registered holder to purchase from us one one-thousandth of a share of Series A Junior Participating Preferred Stock at a price of $520, subject to adjustment under certain circumstances. As a result of stock splits effected in the form of stock dividends in 1998, 2001, and 2005, one Right is associated with eight outstanding shares of common stock. The purchase price for the one-eighth of a Right associated with one share of common stock is effectively $65. Upon the occurrence of certain events specified in the Rights Plan, each holder of a Right (other than an "Acquiring Person," as defined under the Rights Plan) will have the right, upon exercise of such Right, to receive that number of shares of common stock of the Company (or the surviving corporation) that, at the time of such transaction, would have a market price of two times the purchase price of the Right. No shares of Series A Junior Participating Preferred Stock have been issued by us.

Senior Notes

On June 8, 2006, we completed a public offering of $500.0 million aggregate principal amount of Senior Notes, consisting of $250.0 million of floating rate Senior Notes due 2008, with an annual interest rate of three-month LIBOR plus 17 basis points, and $250.0 million of 5.75% Senior Notes due 2011. The net proceeds from the offering of approximately $497.1 million, after deducting underwriting discounts and commissions and expenses, were predominantly used to repurchase outstanding shares of our common stock. In addition, the proceeds were used to repay indebtedness, fund capital expenditures and for other corporate purposes. As of September 30, 2006, we had $250.0 million of the Senior Notes due 2008 issued and outstanding and $249.7 million of the 5.75% Senior Notes due 2011 issued and outstanding.

Stock Repurchases

On December 19, 1997, our Board of Directors authorized a stock repurchase program of up to $150 million. Through a series of increases, the stock repurchase program is now authorized to repurchase up to $2.2 billion. Repurchases are made at the discretion of management and the program will remain in effect until terminated by our Board of Directors. We purchased 48,366,000 shares at a cost of $499.0 million through fiscal 2004. During fiscal 2005, we purchased a total of 3,982,000 shares at a cost of $98.4 million. During fiscal 2006, we purchased a total of 31,725,882 shares at a cost of $1,133.3 million.

Purchases of equity securities during the quarter ended September 30, 2006 are as follows:

Period	Total Number of Shares Purchased	Average Price paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs *(in thousands)*
July 1 – 31, 2006	—	—	—	$834,090
August 1 – 31, 2006	9,878,600	$35.92	9,878,600	$479,256
September 1 – 30, 2006	296,000	$33.63	296,000	$469,303
TOTAL	10,174,600	$35.85	10,174,600	$469,303

Subsequent to September 30, 2006, we have purchased 668,889 shares for $20.0 million through November 30, 2006 under our stock repurchase program as discussed in Note 14 of the Notes to the Consolidated Financial Statements. We have authority remaining to purchase up to an additional $449.3 million in stock as of November 30, 2006.

Dividend Program

Beginning July 22, 2004, we declared a quarterly cash dividend in the amount of $.04 per common share. On July 28, 2005, the quarterly cash dividend was increased to $.05 per common share. We anticipate paying cash dividends in the amount of $.05 per common share on a quarterly basis in fiscal 2007. However, dividends are subject to approval by our Board of Directors each quarter, and the Board has the ability to change the dividend policy at any time.

Equity Compensation

Information regarding equity compensation plans can be located in the section entitled "Equity Compensation Plan Information" in our Proxy Statement of the Annual Meeting of Stockholders to be held January 30, 2007, which sections are incorporated herein by reference.

ITEM 6. Selected Financial Data

The following table sets forth certain selected historical financial data and 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 thereto which are included elsewhere herein. The selected operating and financial position data as of and for each of the five years for the period ended September 30, 2006 have been derived from our audited consolidated financial statements, some of which appear elsewhere in this Annual Report on Form 10-K.

	As of and For the Year Ended September 30,				
	2006	2005	2004	2003	2002[1]
	(in thousands, except per share amounts)				
Operating Data					
Revenue	$ 4,367,864	$ 3,243,186	$ 2,600,986	$ 2,142,877	$ 1,865,796
Operating expenses	(3,196,128)	(2,606,127)	(2,162,601)	(1,849,636)	(1,602,906)
Operating income	1,171,736	637,059	438,385	293,241	262,890
Interest expense	(14,558)	(10,951)	(16,389)	(15,948)	(8,979)
Interest income	14,916	11,281	6,073	2,141	2,008
Other income (expense), net[2]	(11)	15,958	92,668	(3,762)	(3,225)
Income tax expense	(367,473)	(200,305)	(159,696)	(87,495)	(86,199)
Net income	804,610	453,042	361,041	188,177	166,495
Earnings per share[3]:					
Basic	2.55	1.40	1.13	.60	.53
Diluted	2.52	1.38	1.10	.58	.52
Depreciation and amortization	166,763	136,861	125,668	120,213	104,915
Capital expenditures[4]	459,974	323,763	200,577	167,183	179,007
Financial Position Data (at end of period):					
Property, net	$ 1,392,926	$ 1,086,932	$ 913,713	$ 850,340	$ 798,956
Total assets	3,862,288	3,409,642	3,301,330	2,800,135	2,438,543
Long-term debt and capital leases, excluding current maturities	500,140	455	78,936	493,754	489,062
Stockholders' equity[5]	2,146,940	2,492,041	2,102,424	1,658,920	1,418,628
Cash dividends declared per common share	.20	.17	.04	—	—

(1) Includes the effect of the acquisition of OSCA, Inc. in May 2002 from the date of acquisition.

(2) Includes Halliburton patent infringement award of $86.4 million (net of legal expenses) in fiscal 2004 and $12.2 million for the reversal of excess liabilities in the Asia Pacific region. Additionally, it includes $9.0 million in misappropriated funds from the Asia Pacific region repaid to us in fiscal 2005 and $9.5 million for the reversal of excess accrued liabilities in the Asia Pacific region. See Note 12 of the Notes to the Consolidated Financial Statements.

(3) Earnings per share amounts have been restated for all periods presented to reflect the increased number of common shares outstanding resulting from the 2-for-1 stock split effective September 1, 2005.

(4) Excluding acquisitions of businesses.

(5) As disclosed in Note 3 of the Notes to the Consolidated Financial Statements, we have retroactively adjusted beginning retained earnings to adopt the equity method of accounting for our acquisition of a controlling interest in our Algerian joint venture. This adjustment resulted in a $8.3 million increase to beginning retained earnings as reflected in the consolidated statement of stockholders' equity and other comprehensive income. The statement of operations has not been restated as the impact of adopting the equity method was not material in any given period.

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Business

We are engaged in providing pressure pumping services and other oilfield services to the oil and natural gas industry worldwide. Services are provided through four business segments: U.S./Mexico Pressure Pumping, International Pressure Pumping, Canada Pressure Pumping and the Oilfield Services Group.

The U.S./Mexico, International Pressure Pumping and Canada Pressure Pumping segments provide stimulation and cementing services to the petroleum industry throughout the world. Stimulation services are designed to improve the flow of oil and natural gas from producing formations. Cementing services consists of pumping a cement slurry into a well between the casing and the wellbore to isolate fluids that might otherwise damage the casing and/or affect productivity, or that could migrate to different zones, primarily during the drilling and completion phase of a well. See "Business" included elsewhere in this Annual Report on Form 10-K for more information on these operations.

The Oilfield Services Group consists of production chemical services, casing and tubular services, process and pipeline services and completion tools and completion fluids services in the U.S. and select markets internationally.

Market Conditions

Our worldwide operations are primarily driven by the number of oil and natural gas wells being drilled, the depth and drilling conditions of such wells, the number of well completions and the level of workover activity. Drilling activity, in turn, is largely dependent on the price of crude oil and natural gas. These market factors often lead to volatility in our revenue and profitability, especially in the United States and Canada, where we have historically generated in excess of 50% of our revenue. Historical market conditions are reflected in the table below for the twelve months ended September 30:

	2006	% Change	2005	% Change	2004
Worldwide Rig Count[1]:					
U.S.	1,587	20%	1,323	15%	1,155
International[2][3]	905	9%	833	9%	767
Canada	502	20%	420	15%	366
Commodity Prices (average):					
Crude Oil (West Texas Intermediate)	$66.06	23%	$53.52	44%	$37.16
Natural Gas (Henry Hub)	$ 8.16	10%	$ 7.40	33%	$ 5.59

(1) Estimate of drilling activity as measured by average active drilling rigs based on Baker Hughes Inc. rig count information.

(2) Includes Mexico rig count of 85, 111 and 110 for the fiscal years ended September 30, 2006, 2005 and 2004, respectively.

(3) In the quarter ended June 30, 2006, Baker Hughes Inc. began excluding Iran and Sudan rig counts from its published rig count information. International rig count for fiscal 2005 and 2004 has been adjusted to exclude Iran and Sudan for comparability.

U.S. Rig Count

Demand for our pressure pumping services in the U.S. is primarily driven by oil and natural gas drilling activity, which tends to be extremely volatile, depending on the current and anticipated prices of crude oil and natural gas. During the last 10 years, the lowest annual U.S. rig count averaged 601 in fiscal 1999 and the highest annual U.S. rig count averaged 1,587 in fiscal 2006.

International Rig Count

Many countries in which we operate are subject to political, social and economic risks which may cause volatility within any given country. However, our international revenue in total is less volatile because we operate in approximately 50 countries, which provides a reduction of exposure to any one country. Due to the significant investment and complexity of international projects, we believe drilling decisions relating to such projects tend to be evaluated and monitored with a longer-term perspective with regard to oil and natural gas pricing. Additionally, the international market is dominated by major oil companies and national oil companies which tend to have different objectives and more operating stability than the typical independent producer in North America. During the last 10 years, the lowest annual international rig count, excluding Canada, averaged 616 in fiscal 1999 and the highest annual international rig count averaged 905 in fiscal 2006.

Canadian Rig Count

The demand for our pressure pumping services in Canada is primarily driven by oil and natural gas drilling activity, and similar to the U.S., tends to be extremely volatile. During the last 10 years, the lowest annual rig count averaged 212 in fiscal 1999 and the highest annual rig count averaged 502 in fiscal 2006.

Acquisitions

On June 25, 2006, we acquired an additional 2% interest in our Algerian joint venture, Societe Algerienne de Stimulation de Puits Productures d'Hydrocarbures ("BJSP"), for $4.6 million, increasing our total ownership in BJSP to 51%. L'Enterprise de Services aux Puits ("ENSP"), an indirect subsidiary of Sonatrach Petroleum Corp., owns the remaining 49%. BJSP provides coiled tubing and cementing services to the Algerian market. Prior to obtaining controlling interest in BJSP, we accounted for the investment using the cost method, as we could not exercise significant influence over the entity. Following this transaction, which is being accounted for as a step-acquisition, we have control of BJSP and now consolidate the entity. In accordance with Accounting Principles Board ("APB") 18, *Equity Method of Accounting of Investments in Common Stock*, and Accounting Research Bulletin ("ARB") 51, *Consolidated Financial Statements*, we have retroactively adjusted beginning retained earnings to adopt the equity method of accounting for our ownership interest in previous periods. This adjustment resulted in an $8.3 million increase to beginning retained earnings as reflected in the consolidated statement of stockholders' equity and other comprehensive income. The statement of operations has not been restated as the impact of adopting the equity method was not material in any given period.

Following the transaction, the assets and liabilities and results of operations of BJSP are included in our consolidated results, in the International Pressure Pumping segment. The consolidation resulted in an increase of $42.4 million in total current assets (including approximately $14.1 million in cash), $12.1 million in total current liabilities, $19.3 million in minority interest and $0.2 million in goodwill. We are in the process of completing our purchase price allocation for this step acquisition. The pro forma financial information for this acquisition is not included as it is not material to our consolidated financial statements.

On August 15, 2006, we purchased substantially all of the operating assets of Dyna Coil of South Texas, Ltd., Dyna Coil Injection Systems, Inc. and Dynochem, Ltd. (collectively, "Dyna-Coil") for $61.7 million in cash. Dyna-Coil is focused on production optimization services, particularly the installation and service of capillary injection systems and associated products (production chemicals) mostly in the U.S. and Canada and is included in our production chemicals business in the Oilfield Services segment. The acquisition resulted in an increase of $8.2 million in total current assets, $3.4 million in property and equipment, $7.1 million of technology based intangibles and $42.9 million in goodwill. We are in the process of completing our purchase price allocation. The pro forma financial information for this acquisition is not included as it is not material to our consolidated financial statements.

Results of Operations

Consolidated

	2006	% Change	2005	% Change	2004
Consolidated (in millions)					
Revenue	$4,367.9	35%	$3,243.2	25%	$2,601.0
Operating income	$1,171.7	84%	$ 637.1	45%	$ 438.4
Worldwide rig count[1]	2,995	16%	2,576	13%	2,288

(1) Estimate of drilling activity as measured by average active drilling rigs based on Baker Hughes Inc. rig count information.

Results for fiscal 2006 compared to fiscal 2005

Consolidated revenue in fiscal 2006 benefited from increased worldwide drilling activity and pricing improvements in the U.S., Canada, and Latin America. Revenue growth surpassed the increase exhibited by worldwide drilling activity during the same period.

Consolidated operating income also experienced significant growth in fiscal 2006 as a result of the increased revenue described above. All of our business segments showed strong increases in operating income from the same period in the prior year. For fiscal 2006, consolidated operating income margins improved to 27% from 20% reported in fiscal 2005. These margin enhancements were largely due to higher revenue and improved pricing in the U.S. and Canada, in addition to equipment and labor efficiencies.

See discussion below on individual segments for further revenue and operating income variance details.

Results for fiscal 2005 compared to fiscal 2004

Increased drilling activity and pricing improvement in the U.S. and Canada along with activity improvements in the Middle East and Latin America led to the increase in fiscal 2005 revenue compared to fiscal 2004. The increases experienced in fiscal 2005 revenue were slightly offset by revenue decreases in Mexico and for our stimulation vessel in the North Sea.

Fiscal 2005 operating income also benefited from the increased revenue described above, but was hindered by the decrease in activity for the stimulation vessel in the North Sea. For fiscal 2005, consolidated operating income margins improved to 20% from 17% reported in fiscal 2004.

U.S./Mexico Pressure Pumping Segment

	2006	% Change	2005	% Change	2004
Pressure pumping *(in millions)*					
Revenue	$2,353.8	40%	$1,683.2	33%	$1,269.8
Operating income	$ 899.2	71%	524.9	56%	337.0
U.S. rig count[1]	1,587	20%	1,323	15%	1,155
Mexico rig count[1]	85	-23%	111	1%	110

(1) Estimate of drilling activity as measured by average active drilling rigs based on Baker Hughes Inc. rig count information.

Results for fiscal 2006 compared to fiscal 2005

U.S./Mexico pressure pumping revenue increased as a result of increased drilling activity and improved pricing in the U.S. market. Operating regions providing the most revenue growth include the Permian Basin, East Texas, and Rocky Mountain areas. This was slightly offset by lower revenue in Mexico.

Activity: Every operating region within the U.S. experienced considerable revenue growth, due to a 20% increase in U.S. drilling activity from the same period in the prior year. The U.S. revenue improvement was partially offset by lower revenue in Mexico due to lower levels of drilling activity. The average rig count for Mexico decreased 23%, compared to the prior fiscal year.

Price: Price improvement in the U.S. has been supported by the issuance of three price book increases since May of 2005. A U.S. price book with a 15% average price increase was issued on May 1, 2005. Another price book was issued on November 1, 2005 averaging an 11% price increase. Finally, on May 1, 2006 the U.S. issued the latest price book increase. At September 30, 2006, 52% of customers were on the May 1, 2006 price book. The degree of acceptance for any price book increase described above varies by customer and depends on activity levels and competitive pressures.

The improvement in U.S./Mexico pressure pumping operating income was largely the result of the increase in U.S. revenue described above. U.S. pricing improvements increased operating income without any associated cost. In addition, operating income gained from labor efficiencies. Activity increases occurred without a proportional increase in headcount. Average headcount increased 12% in fiscal 2006, with revenue increasing 40%. Cost efficiencies are also being obtained through utilization of newer, more efficient and more modern equipment (see "Business" included elsewhere in this Annual Report on Form 10-K for information on the U.S. fleet recapitalization initiative).

Results for fiscal 2005 compared to fiscal 2004

Increased U.S. drilling activity of 15% from fiscal 2004 as well as improved pricing in the U.S. led the increase in revenue. As of September 30, 2005, approximately 60% of our customers were on the U.S. price book that became effective on May 1, 2005. Lower Mexico activity resulted in a 36% revenue reduction for Mexico, which slightly offset the gains experienced in the U.S. operations. The decrease in Mexico activity, specifically from the Burgos area, was caused by our primary customer in Mexico curtailing spending on our contract in that area.

The increases in revenue described above, coupled with labor efficiency gains, contributed to the increase in operating income. Labor efficiencies were achieved through an increase in activity without a proportional increase in headcount, thereby increasing employee utilization per job. The headcount for fiscal 2005 increased 11% compared to fiscal 2004, with revenue increasing 33%. Utilization of newer, more efficient and more modern equipment also contributed to the increase in operating income (see the "Business" section for information on the U.S. fleet recapitalization initiative). In addition, the pricing improvement described above directly increased operating income without any associated cost. As with revenue, the increase in U.S. operating income was slightly offset by the decrease in our Mexico operations described above.

International Pressure Pumping Segment

	2006	% Change	2005	% Change	2004
Pressure Pumping *(in millions)*					
Revenue	$884.7	28%	$693.5	16%	$597.9
Operating income	$138.1	78%	$ 77.5	76%	$ 44.1
International rig count, excluding Mexico[1]	820	13%	723	10%	657

(1) Estimate of drilling activity as measured by average active drilling rigs based on Baker Hughes Inc. rig count information.

Results for fiscal 2006 compared to fiscal 2005

The following table summarizes the change in revenue for fiscal 2006 compared to fiscal 2005 for each of the operating segments of International Pressure Pumping:

	% change in Revenue
Europe/Africa	29%
Middle East	29%
Asia Pacific	32%
Russia	5%
Latin America	31%

All of our operating segments contributed to the revenue increase in fiscal 2006. Activity growth in Argentina, Venezuela, Columbia and Brazil as well as in other markets within the region led the Latin American revenue increase. Latin America's revenue increase of 31% surpassed the average rig count increase of 16%. Middle East revenue increased largely due to strong rig activity in Kazakhstan and overall activity increases in Saudi Arabia. Average drilling activity for the Middle East increased 17%. These contributions were slightly affected by lower revenue due to the conclusion of Bangladesh blowout work in the prior year. Activity increases in the North Sea and Africa contributed to revenue improvement in Europe/Africa. New Zealand and Vietnam for Asia Pacific also added to the overall increase in revenue in fiscal 2006. As noted previously, we acquired a controlling interest in BJSP and accordingly, now consolidate its revenue beginning July 1, 2006. Excluding BJSP, revenue would have increased 24% in Europe/Africa.

Operating income increased as the result of improved revenues in Latin America and the Middle East as described above, as well as improved margins from Asia Pacific operations. Also contributing to the improved operating income were higher equipment utilization as well as labor efficiencies. Labor efficiencies were achieved through an increase in activity without a proportional increase in headcount, thereby increasing employee utilization per job. Headcount increased 7% compared to the same period in the prior year, while revenue increased 28%. Consequently, operating income margins improved to 16% from 11% for fiscal 2006 compared to the prior fiscal year.

Results for fiscal 2005 compared to fiscal 2004

The following table summarizes the change in revenue for fiscal 2005 compared to fiscal 2004 for each of the operating segments of International Pressure Pumping:

	% change in Revenue
Europe/Africa	6%
Middle East	39%
Asia Pacific	2%
Russia	17%
Latin America	20%

Middle Eastern and Latin American operations were the primary contributors to the revenue increase. Increased fracturing and coiled tubing activity in India and Saudi Arabia and well control work in Bangladesh were major contributions to the increase in the Middle East. Average drilling activity in Latin America increased 19% compared to fiscal 2004, primarily enhancing revenue in Argentina and Brazil. Revenue in Argentina was up appreciably as a result of increased stimulation and coiled tubing activity. North Sea activity gains in the U.K. and Norway were almost entirely offset by lower stimulation vessel activity in the Europe/Africa operations. Throughout fiscal 2005, our primary customer for the stimulation vessel experienced delays in its well delivery schedule, resulting in a 53% decline in revenue compared to fiscal 2004. Asia Pacific revenue growth was from improvements in Thailand and Vietnam, mostly offset by declines in Malaysia. In Malaysia, major customers reduced their drilling and workover programs leading to a 29% revenue decline. Russian revenue increased from the overall market increase.

Operating income increased as a result of the improved revenues as described above. Similar to the U.S./ Mexico Pressure Pumping segment, labor efficiencies were achieved. The headcount for fiscal 2005 increased 5% compared to fiscal 2004, with revenue increasing 16%. These operating income increases were partially offset by lower activity levels with our stimulation vessel in the North Sea. Since there are significant fixed costs associated with operating the stimulation vessel, there was a decline in operating profit.

Canada Pressure Pumping

	2006	% Change	2005	% Change	2004
Pressure pumping *(in millions)*					
Revenue	$481.4	38%	$348.4	19%	$293.5
Operating income	$102.1	75%	$ 58.3	23%	$ 47.3
Canada rig count(1)	502	20%	420	15%	366

(1) Estimate of drilling activity as measured by average active drilling rigs based on Baker Hughes Inc. rig count information.

Results for fiscal 2006 compared to fiscal 2005

Geographic expansion, price improvement and increased average rig count contributed to our revenue improvement in Canada. During fiscal 2006, we opened two new bases in active oil and gas producing areas in Canada. Compared to the same period in the prior year, Canadian operations generated a 38% increase in revenue with average active drilling rigs increasing 20%. As revenues are primarily denominated in Canadian Dollars, a weakening U.S. dollar, compared to the Canadian dollar, also improved revenue 10%.

Operating income improved as a result of the revenue increases described above, coupled with labor efficiencies. Headcount increased 10%, with revenue increasing 38%. While favorable foreign exchange rates in Canada increased revenue, they had minimal impact on operating income as most of our expenses are also denominated in Canadian dollars.

Results for fiscal 2005 compared to fiscal 2004

Canadian revenue increased as a result of a 15% increase in activity and improved pricing. We issued a new price book for our Canadian operation on June 1, 2005. The new price book averaged 9% higher than the previous price book.

Operating income improved as a result of the revenue increases described above, coupled with labor efficiencies. Headcount increased 6%, with revenue increasing 19%.

Oilfield Services Group

	2006	% Change	2005	% Change	2004
(in millions)					
Revenue	$648.0	25%	$517.7	18%	$438.8
Operating income	132.4	96%	67.6	25%	54.0

Results for fiscal 2006 compared to fiscal 2005

The following table summarizes the change in revenue for fiscal 2006 compared to fiscal 2005 for each of the operating segments of the Oilfield Services Group:

	% Change in Revenue
Tubular Services	23%
Process and Pipeline Services	17%
Chemical Services	45%
Completion Tools	20%
Completion Fluids	32%

The increase in revenue in fiscal 2006 was largely due to contributions from Completion Fluids, Chemical Services, and Process and Pipeline Services. Overall activity increases, primarily in the U.S. and Canada, boosted Process and Pipeline Services revenue, while the Completion Fluids and Chemical Services revenue increase was more attributable to increased U.S. market activity.

Operating income margins for the Oilfield Services Group increased to 20% for fiscal 2006 compared to 13% for fiscal 2005, with the revenue increases described above being the primary contributor to the increase.

Results for fiscal 2005 compared to fiscal 2004

The following table summarizes the change in revenue for fiscal 2005 compared to fiscal 2004 for each of the operating segments of the Oilfield Services Group:

	% Change in Revenue
Tubular Services	21%
Process & Pipeline Services	14%
Chemical Services	13%
Completion Tools	5%
Completion Fluids	37%

Revenue from each service line within the Oilfield Services Group increased during fiscal 2005. However, the increase in revenue from Completion Tools was minimal due to severe hurricane activity experienced in the Gulf of Mexico during our fourth fiscal quarter of 2005. This decrease was offset by increases in revenue internationally. Most of the revenue increase in Completion Fluids was as a result of increased product sales in the U.S., Mexico, and Norway. Tubular Services' revenue benefited from increased activity in the North Sea and Asia Pacific.

Fiscal 2005 operating income margins were consistent with fiscal 2004 for all service lines. Operating income improved for the reasons described above; however, there were additional costs for worker's compensation and write off of uncollectible accounts receivable.

Outlook

As stated under "Market Conditions" above, our worldwide operations are primarily driven by the number of oil and natural gas wells being drilled, the depth and drilling conditions of such wells, the number of well completions and the level of workover activity. Drilling activity, in turn, is largely dependent on the price of crude oil and natural gas. Worldwide drilling activity during fiscal 2006 has been the highest since 1985. If the prices of crude oil and natural gas in fiscal 2007 remains consistent with the average prices for these commodities in fiscal 2006, we expect activity in fiscal 2007 to surpass the fiscal 2006 activity levels both in the U.S. and International markets.

Our results of operations also depend heavily on pricing. During fiscal 2006, we have experienced improved pricing in the U.S., Canadian, and select markets internationally.

Based on our forecasted increase in rig activity and improved pricing, we expect continued improvement in our results of operations in fiscal 2007. We expect revenue improvement from all of our business segments.

Other Expenses

The following table sets forth our other operating expenses (in millions):

	2006	% of Revenue	2005	% of Revenue	2004	% of Revenue
Research and engineering	$ 63.9	1.5%	$ 54.2	1.7%	$47.3	1.8%
Marketing expense	103.3	2.4%	92.3	2.8%	82.1	3.2%
General and administrative expense	132.0	3.0%	111.3	3.4%	79.0	3.0%

Research and engineering and marketing expense: The total of these expenses increased 14% for fiscal 2006, compared to fiscal 2005. The increase was due primarily to higher activity levels experienced throughout our business. However, each of these expenses were lower as a percent of revenue compared to the same periods in the prior fiscal year. This is due to our revenue increasing at a higher rate than expenses related to research and engineering and marketing.

The aggregate of these expenses increased 13% for fiscal 2005, compared to fiscal 2004. As a percent of revenue, each of these expenses was relatively consistent with the same periods of the prior year.

General and administrative expense: These expenses increased 19% in fiscal 2006, compared to 2005, due primarily to an overall increase in salaries and incentive expense caused by increased personnel. Average headcount in this area increased 9% compared to fiscal 2005. In addition, stock based compensation expense increased $2.5 million related to our adoption of Statement of Financial Accounting Standards ("SFAS") 123(R) on October 1, 2005 (see Note 13 of the Notes to the Consolidated financial Statements).

Legal and other costs associated with the ongoing investigation in our Asia Pacific Region (see "Investigations Regarding Misappropriation and Possible Illegal Payments" below), as well as fees of $10.9 million related to preparations for our first year under Section 404 of the Sarbanes-Oxley Act, led to higher general and administrative expenses for fiscal 2005 that did not occur in fiscal 2004. In addition, due to increased activity levels, labor costs and incentive compensation costs increased during fiscal 2005, compared to fiscal 2004.

The following table shows a comparison of interest expense, interest income, and other income (expense), net (in millions):

	2006	2005	2004
Interest expense	$(14.6)	$(11.0)	$(16.4)
Interest income	14.9	11.3	6.1
Other income (expense), net	—	16.0	92.7

Interest Expense and Interest Income: The increase in interest expense of $3.6 million for fiscal 2006, compared to fiscal 2005, was due to our public offering of $500.0 million aggregate principal amount of Senior Notes in June 2006 as well as borrowing $160.0 million under our Revolving Credit Facility during the period. See "Liquidity and Capital Resources" below for further discussion of the debt issuance and the Revolving Credit Facility agreement. As a result, interest expense, net of interest income, in fiscal 2007 will increase and is projected to be approximately $29 million.

In April 2005, we redeemed the outstanding Convertible Senior Notes due 2022 for $422.4 million. As a result, interest expense decreased for fiscal 2005.

Interest income increased $3.6 million in fiscal 2006, compared to the prior year, as a result of increased cash and cash equivalents balances as well as favorable interest rates.

Interest income increased for fiscal 2005, compared to fiscal 2004, as a result of increases in average cash and cash equivalents.

Other Income (Expense), net: In fiscal 2006, we received $2.8 million for the recovery of misappropriated funds (see "Investigations Regarding Misappropriation and Possible Illegal Payments" below), offset by other expenses. Other Income increased during fiscal 2005 due to recording a gain of $9.0 million relating to the recovery of misappropriated funds in the first quarter and $9.5 million recorded in the fourth quarter to reflect the reversal of excess accrued liabilities in the Asia Pacific region.

For fiscal 2004, we recorded a gain of $86.4 million for the Halliburton award (see Note 12 of the Notes to the Consolidated Financial Statements). In addition, $12.2 million was recorded for the reversal of excess liabilities in the Asia Pacific region.

For additional details of this account, see Note 12 of the Notes to the Consolidated Financial Statements.

Liquidity and Capital Resources

Historical Cash Flow

The following table sets forth the historical cash flows for the years ended September 30 (in millions):

	2006	2005	2004
Cash flow from operations	$ 832.5	$ 545.7	$ 528.6
Cash flow used in investing	(503.2)	(86.2)	(443.7)
Cash flow (used) in / provided by financing	(593.4)	(527.8)	58.2
Effect of exchange rate changes on cash	—	—	3.9
Change in cash and cash equivalents	$(264.1)	$ (68.2)	$ 147.1

Fiscal 2006

Cash flow from operations increased principally as a result of increased activity levels. Our working capital decreased $139.8 million at September 30, 2006 compared to September 30, 2005. This is largely a result of utilizing our cash to repurchase treasury stock. Accounts receivable increased $215.0 million, inventory increased $111.2 million, and accounts payable increased $105.8 million primarily as a result of an increase in worldwide activity levels. Also as a result of increased activity, we increased the number of employees and therefore, our employee compensation and benefits liability increased $26.8 million.

The cash flow used in investing was almost entirely due to $460.0 million of purchases of property, plant, and equipment in fiscal 2006. We used $52.2 million to make two acquisitions (see Note 3 in the Notes to the Consolidated Financial Statements).

In fiscal 2006, we spent $1,133.3 million to repurchase 31.7 million shares of stock. During the year, cash flow from financing activities included proceeds from our additional long-term debt in the amount of $499.7 million in Senior Notes. These proceeds were primarily used to repurchase treasury stock. We also had $160.0 million in borrowings under our Revolving Credit Facility and paid dividends of $64.3 million.

Fiscal 2005

Our working capital increased $136.8 million at September 30, 2005 compared to September 30, 2004. Accounts receivable increased $154.7 million, inventory increased $53.2 million, and accounts payable and accrued employee compensation increased $81.8 million and $26.9 million, respectively, primarily as a result of an increase in U.S. and Canadian activity. In April 2005, we redeemed the outstanding Convertible Senior notes for $422.4 million (see Note 5 of the Notes to the Consolidated Financial Statements) thereby reducing cash and cash equivalents and current debt. In addition, the outstanding unsecured 7% Series B Notes in the amount of $79.0 million were classified as current during fiscal 2005 (see Note 5 of the Notes to the Consolidated Financial Statements).

The cash flow provided by investing was primarily attributable to our investment in U.S. treasury notes maturing during 2005 in the amount of $229.8 million offset by capital expenditures of $323.8 million for fiscal 2005.

Cash flows used in financing were primarily the result of the redemption of all of the outstanding Convertible Senior Notes referred to above, repurchases of our common stock totaling $98.4 million and the payment of dividends in the amount of $51.9 million during fiscal 2005.

Fiscal 2004

Increased activity resulted in positive cash flow from operations, as well as $86.4 million of cash received in connection with the Halliburton award (see Note 12 of the Notes to the Consolidated Financial Statements). Accounts receivable increased $78.0 million and accounts payable increased $31.5 million primarily as a result of an increase in U.S. activity.

Cash flow from investing was primarily attributable to the purchase of U.S. treasury bills and notes for $229.9 million in May 2004, which have maturities between six and ten months.

Cash flow from financing activities included proceeds from stock option exercises in the amount of $61.4 million.

During fiscal 2004, due to the poor market performance of the pension plan investments in fiscal 2001 and 2002, we made required pension contributions of $10.4 million, and made a discretionary contribution of an additional $9 million.

On July 22, 2004, we announced the initiation of a regular quarterly cash dividend and declared a dividend of $.04 per common share, paid on October 15, 2004 to stockholders of record at the close of business on September 15, 2004 in the aggregate amount of $12.9 million.

Liquidity and Capital Resources

Cash flows from operations are expected to be our primary source of liquidity in fiscal 2007. Our sources of liquidity also include cash and cash equivalents of $92.4 million at September 30, 2006 and the available financing facilities listed below (in millions):

Financing Facility	Expiration	Borrowings at September 30, 2006	Available at September 30, 2006
Revolving Credit Facility	June 2009	$160.0	$240.0
Discretionary	Various times within the next 12 months	$ 0.3	$ 64.1

On June 8, 2006, we completed a public offering of $500.0 million aggregate principal amount of Senior Notes, consisting of $250.0 million of floating rate Senior Notes due 2008, with an annual interest rate of three-month LIBOR plus 17 basis points, and $250.0 million of 5.75% Senior Notes due 2011. The net proceeds from the offering of approximately $497.1 million, after deducting underwriting discounts and commissions and expenses, were used primarily to repurchase outstanding shares of common stock and also repay indebtedness, fund capital expenditures and for other corporate purposes. As of September 30, 2006, we had $250.0 million of the Senior Notes due 2008 issued and outstanding and $249.7 million, net of discount, of the 5.75% Senior Notes due 2011 issued and outstanding.

In June 2004, we replaced our then existing credit facility with a revolving credit facility (the "Revolving Credit Facility") that permits borrowings up to $400 million in principal amount. The Revolving Credit Facility includes a $50 million sublimit for the issuance of standby letters of credit and a $20 million sublimit for swingline loans. Swingline loans have short-term maturities and the remaining amounts outstanding under the Revolving Credit Facility become due and payable in June 2009. Interest on outstanding borrowings is charged based on prevailing market rates. We are charged various fees in connection with the Revolving Credit Facility, including a commitment fee based on the average daily unused portion of the commitment, totaling $0.5 million in fiscal 2006 and 2005. In addition, the Revolving Credit Facility charges a utilization fee on all outstanding loans and letters of credit when usage of the Revolving Credit Facility exceeds 33%, though there were no such charges in fiscal 2005, and no material fees in fiscal 2006. At September 30, 2006, there was $160.0 million in borrowings outstanding. There were no outstanding borrowings under the Revolving Credit Facility at September 30, 2005.

The Senior Notes and Revolving Credit Facility include various customary covenants and other provisions, including the maintenance of certain profitability and solvency ratios, none of which materially restrict our activities. We are currently in compliance with these covenants.

In addition to the Revolving Credit Facility, we had $64.4 million of unsecured, discretionary lines of credit at September 30, 2006, which expire at the bank's discretion. There are no requirements for commitment fees or compensating balances in connection with these lines of credit and interest is at prevailing market rates. There was $0.3 million and $3.4 million in outstanding borrowings under these lines of credit at September 30, 2006 and 2005, respectively. The weighted average interest rates on short-term borrowings outstanding as of September 30, 2006 and 2005 were 5.95% and 7.75%, respectively.

Management believes that cash flows from operations combined with cash and cash equivalents, the Revolving Credit Facility and other discretionary credit facilities provide us with sufficient capital resources and liquidity to manage our routine operations, meet debt service obligations, fund projected capital expenditures, repurchase common stock, pay a regular quarterly dividend and support the development of our short-term and long-term operating strategies. If the discretionary lines of credit are not renewed, or if borrowings under these lines of credit otherwise become unavailable, we expect to refinance this debt by arranging additional committed bank facilities or through other long-term borrowing alternatives.

At September 30, 2005, we had issued and outstanding $79.0 million of unsecured 7% Series B Notes due February 1, 2006, net of discount. This debt obligation was repaid with available cash on the maturity date, February 1, 2006.

Cash Requirements

We anticipate capital expenditures to be $690 million to $700 million in fiscal 2007, compared to $460 million in fiscal 2006. The 2007 capital expenditure program is expected to consist primarily of capital for facilities, new pressure pumping equipment, new equipment for our Oilfield Services Group, and capital to extend the useful life of existing assets. We have made significant progress adding new equipment. However, much of the older equipment still remains in operation due to the increases in market activity in the U.S. During fiscal 2004, we expanded our U.S. fleet recapitalization initiative to include additional equipment, such as cementing, nitrogen and acidizing equipment. Recapitalization of our pressure pumping equipment in Canada began in fiscal 2005. The actual amount of fiscal 2007 capital expenditures will depend primarily on maintenance requirements and expansion opportunities and our ability to execute our budgeted capital expenditures.

In fiscal 2007, our minimum pension and postretirement funding requirements are anticipated to be approximately $8.1 million. We contributed $9.2 million during fiscal 2006.

We paid cash dividends in the amount of $.05 per common share on a quarterly basis in fiscal 2006, totaling $64.3 million in fiscal 2006. We anticipate paying a quarterly dividend in fiscal 2007; however, dividends are subject to approval of our Board of Directors each quarter and the Board has the ability to change the dividend policy at any time.

As of September 30, 2006, we had $250.0 million of the Senior Notes due 2008 issued and outstanding and $249.7 million of the 5.75% Senior Notes due 2011 issued and outstanding, net of discount (collectively "the Notes"). We expect cash paid for net interest expense (net of interest income) will be approximately $29 million in fiscal 2007.

Subsequent to September 30, 2006, we have purchased 668,889 shares for $20.0 million through November 30, 2006 under our stock repurchase program as discussed in Note 14 of the Notes to the Consolidated Financial Statements. We have authority remaining to purchase up to an additional $449.3 million in stock as of November 30, 2006.

The following table summarizes our contractual cash obligations and other commercial commitments as of September 30, 2006 (in thousands):

Contractual Cash Obligations	Total	Less than 1 year	1-3 Years	4-5 Years	After 5 Years
Long term and short term debt	$ 660,274	$160,274	$250,000	$250,000	$ —
Interest on long term debt and capital leases	98,036	29,963	39,323	28,750	—
Capital lease obligations	446	240	206	—	—
Operating leases	132,831	38,382	59,565	25,822	9,062
Equipment financing arrangements[1]	122,756	23,803	66,368	32,585	—
Purchase obligations[2]	534,307	534,307	—	—	—
Purchase commitments[3]	139,015	37,192	48,798	33,873	19,152
Other long-term liabilities[4]	81,349	1,025	144	96	80,084
Total contractual cash obligations	$1,769,014	$825,186	$464,404	$371,126	$108,298

(1) As discussed below, we have the option, but not the obligation, to purchase the pumping service equipment in these two partnerships for approximately $27 million and $32 million in 2009 and 2010, respectively. Currently, we expect to purchase the pumping service equipment and have therefore included the option payments in the table above.

(2) Includes agreements to purchase goods or services that have been approved and that specify all significant terms (pricing, quantity and timing). Our policies do not require a purchase order to be completed for items that are under $200 and are for miscellaneous items, such as office supplies.

(3) We have entered into agreements with certain suppliers to ensure that a certain level of materials are maintained in the U.S. and Canada.

(4) Includes expected cash payments for long-term liabilities reflected in the consolidated balance sheet where the amounts and timing of the payment are known. Amounts include: Asset retirement obligations, known pension funding requirements, post-retirement benefit obligation, environmental accruals and other miscellaneous long-term obligations. Amounts exclude: Deferred gains (see "*Off Balance Sheet Transactions*" below), pension obligations in which funding requirements are uncertain and long-term contingent liabilities.

We expect that cash and cash equivalents and cash flows from operations will generate sufficient cash flows to fund all of the cash requirements described above.

Off Balance Sheet Transactions

In 1999, we contributed certain pumping service equipment to a limited partnership. We own a 1% interest in the limited partnership. The equipment is used to provide services to our customers for which we pay a service fee over a period of at least six years, but not more than 13 years, at approximately $12 million annually. This is accounted for as an operating lease. We assessed the terms of this agreement and determined it was a variable interest entity as defined in FIN 46, *Consolidation of Variable Interest Entities*. However, we were not deemed to be the primary beneficiary, and therefore, consolidation was not required. The transaction resulted in a gain that is being deferred and amortized over 13 years. The balance of the deferred gain was $16.1 million and $22.1 million as of September 30, 2006 and September 30, 2005, respectively. The agreement permits substitution of equipment within the partnership as long as the implied fair value of the new property transferred in at the date of substitution equals or exceeds the implied fair value, as defined, of the current property in the partnership that is being replaced. As a result of the substitutions, the deferred gain was reduced by $2.8 million in fiscal 2006 and $1.1 million in fiscal 2005. In September 2010, we have the option, but not the obligation, to purchase the pumping service equipment for approximately $32 million. We currently have the intent to exercise this option.

In 1997, we contributed certain pumping service equipment to a limited partnership. We own a 1% interest in the limited partnership. The equipment is used to provide services to our customers for which we pay a service fee over a period of at least eight years, but not more than 13 years, at approximately $10 million annually. This is accounted for as an operating lease. We assessed the terms of this agreement and determined it was a variable interest entity as defined in FIN 46, *Consolidation of Variable Interest Entities*. However, we were not deemed to be the primary beneficiary, and therefore, consolidation was not required. The transaction resulted in a gain that is being deferred and amortized over 12 years. There was no deferred gain at September 30, 2006 and the deferred gain balance at September 30, 2005 was $0.3 million. The agreement permits substitution of equipment within the partnership as long as the implied fair value of the new property transferred in at the date of substitution equals or exceeds the implied fair value, as defined, of the current property in the partnership that is being replaced. As a result of the substitutions, the deferred gain was reduced by $0.3 million in fiscal 2006. In June 2009, we have the option, but not the obligation, to purchase the pumping service equipment for approximately $27 million. We currently have the intent to exercise this option.

The option prices to purchase the equipment under the partnerships depend in part on the fair market value of the equipment held by the partnerships at the time the option are exercised as well as other factors specified in the agreements.

Contractual Obligations

We routinely issue Parent Company Guarantees ("PCGs") in connection with service contracts entered into by our subsidiaries. The issuance of these PCGs is frequently a condition of the bidding process imposed by our customers for work in countries outside of North America. The PCGs typically provide that we guarantee the performance of the services by our local subsidiary. The term of these PCGs varies with the length of the service contract. To date, the parent company has not been called upon to perform under any of these PCGs.

We arrange for the issuance of a variety of bank guarantees, performance bonds and standby letters of credit. The vast majority of these are issued in connection with contracts we, or our subsidiary, have entered into with customers. The customer has the right to call on the bank guarantee, performance bond or standby letter of credit in the event that we, or our subsidiary, default in the performance of services. These instruments are required as a condition to being awarded the contract, and are typically released upon completion of the contract. The balance of these instruments are predominantly standby letters of credit issued in connection with a variety of our financial obligations, such as in support of fronted insurance programs, claims administration funding, certain employee benefit plans and temporary importation bonds. The following table summarizes our other commercial commitments as of September 30, 2006 (in thousands):

		Amount of commitment expiration per period			
Other Commercial Commitments	**Total Amounts Committed**	**Less than 1 Year**	**1–3 Years**	**4–5 Years**	**Over 5 Years**
Standby Letters of Credit	$ 62,821	$ 52,274	$10,547	$ —	$ —
Guarantees	105,719	51,727	19,860	20,080	14,052
Total Other Commercial Commitments	$168,540	$104,001	$30,407	$20,080	$14,052

Investigations Regarding Misappropriation and Possible Illegal Payments

In October 2004, the Company received a report from a whistleblower alleging that its Asia Pacific Region Controller had misappropriated Company funds in fiscal 2001. The Company began an internal investigation into the misappropriation and whether other inappropriate actions occurred in the Region. The Region Controller admitted to multiple misappropriations totaling approximately $9.0 million during a 30-month period ended April 2002. The misappropriations of approximately $9.0 million were repaid to the Company and the Region Controller's employment was terminated. The misappropriations were an expense of the Company in the form of theft that were recorded in the Consolidated Statement of Operations in periods prior to April 2002. The $9.0 million repayment represents a gain contingency and was reflected in Other Income in the Consolidated Condensed Statement of Operations for the quarter ended December 31, 2004 in accordance with SFAS 5, *Accounting for Contingencies*.

The Company is continuing to investigate whether additional funds were misappropriated beyond the $9.0 million originally identified. The Company has identified an additional $1.7 million that it believes was misappropriated by the former Region Controller. The additional $1.7 million of likely misappropriations were expenses of the Company that were recorded in the Consolidated Statement of Operations in periods prior to April 2002. It is possible that additional information could emerge resulting in further adjustments in the Consolidated Statements of Operations, but no material adjustments are known at this time.

In October 2004, the Company also received whistleblower allegations that illegal payments to foreign officials had been made in the Asia Pacific Region. The Audit Committee of the Board of Directors engaged independent counsel to conduct a separate investigation to determine whether any such illegal payments were made. The investigation found information indicating a significant likelihood that payments, made by the Company to an entity in the Asia Pacific Region with which the Company has certain contractual relationships, were then used to make payments to government officials in the Asia Pacific Region. This information included information indicating that certain employees of the Company in the Asia Pacific Region believed that the funds paid to the entity would be used to make payments to government officials. The payments, which may have been illegal, aggregated approximately $2.6 million and were made from fiscal 1999 through 2004.

Thereafter, in December 2005, the Company received a payment of approximately $2.8 million from the entity referenced above. The entity said that the funds represented the $2.6 million of funds described above, plus an interest amount, and that the $2.6 million had been misappropriated for the benefit of certain of that entity's employees and was not used to make payments to government officials. The Audit Committee's investigation was not able to verify this claim. The $2.8 million payment represents a gain contingency and was reflected in Other Income in the Consolidated Condensed Statement of Operations for the quarter ended December 31, 2005 in accordance with SFAS 5, *Accounting for Contingencies*.

The Company and the Audit Committee also investigated a large volume of other payments made by the Company during the period of fiscal 1998 through 2004 in the Asia Pacific Region. With respect to approximately $10 million of these payments, the investigations to date either have not been able to establish the legitimacy of the transactions reflected in the underlying documents or have not been able to resolve questions about the adequacy of the underlying documents to support the accounting entries. These payments may have been proper, but due to circumstances surrounding the payments, the investigations have not been able to determine whether theft, illegal payments or other improprieties may have been involved. The payments have been previously expensed, and therefore the Company believes that no additional expense is required to be recorded for such payments.

The Company has voluntarily disclosed information found in the special Audit Committee investigation, as well as related information from the Company's theft investigation, to the U.S. Department of Justice ("DOJ") and U.S. Securities and Exchange Commission ("SEC") and is engaged in ongoing discussions with these authorities as they review the matter. The Company cannot predict whether further investigative efforts may be required or initiated by the authorities.

In connection with discussions regarding possible illegal payments in the Asia Pacific Region, U.S. government officials raised a question whether the Company had made illegal payments to a contractor or intermediary to obtain business in a country in Central Asia. The Audit Committee has investigated this question. The Company has voluntarily disclosed information found in the investigation to the DOJ and SEC and is engaged in ongoing discussions with these authorities as they review the matter.

The DOJ, SEC and other authorities have a broad range of civil and criminal sanctions under the U.S. Foreign Corrupt Practices Act and other laws, which they may seek to impose against corporations and individuals in appropriate circumstances including, but not limited to, injunctive relief, disgorgement, fines, penalties and modifications to business practices and compliance programs. Such agencies and authorities have entered into agreements with, and obtained a range of sanctions against, several public corporations and individuals arising from allegations of improper payments and deficiencies in books and records and internal controls, whereby civil and criminal penalties were imposed, including in some cases multi-million dollar fines and other sanctions. We are in discussions with the DOJ and SEC regarding certain of the matters described above. It is not possible to accurately predict at this time when any of these matters will be resolved. Based on current information, we cannot predict the outcome of such investigations, whether we will reach resolution through such discussions or what, if any, actions may be taken by the DOJ, SEC or other authorities or the effect the foregoing may have on our consolidated financial statements.

The misappropriations and related accounting adjustments in the Asia Pacific Region were possible because of certain internal control operating deficiencies. During fiscal 2002, the Company implemented policy changes worldwide for disbursements. Significant personnel changes were also made in the Asia Pacific Region. The Company has assigned a new Region Manager and a new Region Controller, an Assistant Controller and replaced several accountants in the Asia Pacific region. The Company also took further disciplinary action against personnel in the Region. In addition, we have put in place an Internal Control and Process Improvement function, led by an internal control manager at the corporate office and supported by managers at each of our five regional bases worldwide to document, enhance, and test our control processes.

Critical Accounting Policies

For an accounting policy to be deemed critical, the accounting policy must first include an estimate that requires a company to make assumptions about matters that are highly uncertain at the time the accounting estimate is made. Second, different estimates that the company reasonably could have used for the accounting estimate in the current period, or changes in the accounting estimate that are reasonably likely to occur from period to period, must have a material impact on the presentation of the company's financial condition or results of operations.

Estimates and assumptions about future events and their effects cannot be perceived with certainty. We base our estimates on historical experience and on other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. Materially different results can occur as circumstances change and additional information becomes known, including estimates not deemed "critical" under the proposed rule by the SEC. We believe the following are the most critical accounting policies used in the preparation of our consolidated financial statements and the significant judgments and uncertainties affecting the application of these policies. The selection of accounting estimates, including those deemed "critical," and the associated disclosures in this discussion have been discussed by management with the Audit Committee of the Board of Directors. The critical accounting policies should be read in conjunction with the disclosures elsewhere in the Notes to the Consolidated Financial Statements. Significant accounting policies are discussed in Note 2 to the Consolidated Financial Statements.

Goodwill: We account for goodwill in accordance with SFAS 142, *Goodwill and Other Intangible Assets.* SFAS 142 requires goodwill to be reviewed for possible impairment using fair value measurement techniques on an annual basis, or if circumstances indicate that an impairment may exist. Specifically, goodwill impairment is determined using a two-step process. The first step of the goodwill impairment test compares the fair value of a reporting unit to its net book value, including goodwill. If the fair value of the reporting unit exceeds the net book value, no impairment is required and the second step is unnecessary. If the fair value of the reporting unit is less than the net book value, the second step is performed to determine the amount of the impairment, if any. Fair value measures include quoted market price, present value technique (estimate of future cash flows), and a valuation technique based on multiples of earnings or revenue. The second step compares the implied fair value of a reporting unit with the net book value of the reporting unit. If the net book value of a reporting unit exceeds the implied fair value, an impairment loss shall be recognized in the amount equal to that excess. The implied fair value is determined in the same manner as the amount of goodwill recognized in a business combination. That is, the fair value of the reporting unit is allocated to all the assets and liabilities as if the reporting unit had just been acquired in a business combination and the fair value of the reporting unit was the purchase price paid to acquire the reporting unit.

Determining fair value and the implied fair value of a reporting unit is judgmental and often involves the use of significant estimates and assumptions. These estimates and assumptions could have a significant impact on whether or not an impairment charge is recognized and also the magnitude of the impairment charge. Our estimate of fair value is primarily determined using discounted cash flows. This approach uses significant assumptions such as a discount rate, growth rate, terminal value multiples, rig count, our price book increases or decreases, and inflation rate.

No impairment adjustment was necessary to our $928.3 million goodwill balance at September 30, 2006. See Note 11 of the Notes to the Consolidated Financial Statements for more information on goodwill.

Pension Plans: Pension expense is determined in accordance with the provisions of SFAS 87, *Employers' Accounting for Pensions*. In accordance with SFAS 87, we utilize an estimated long-term rate of return on plan assets and any difference from the actual return is the unrecognized gain/loss which is amortized into earnings in future periods.

We determine the annual net periodic pension expense and pension plan liabilities on an annual basis using a third-party actuary. In determining the annual estimate of net periodic pension cost, we are required to make an evaluation of critical assumptions such as discount rate, expected long-term rate of return on plan assets and expected increase in compensation levels. These assumptions may have an effect on the amount and timing of future contributions. Discount rates are based on high quality corporate fixed income investments. Long-term rate of return assumptions are based on actuarial review of our asset allocation and returns being earned by similar investments. The rate of increase in compensation levels is reviewed with the actuaries based upon our historical salary experience. The effects of actual results differing from our assumptions are accumulated and amortized over future periods, and, therefore, generally affect our recognized expense in future periods.

In fiscal 2007, we will have a pension and postretirement funding requirement of $8.1 million. We expect to fund this amount with cash flows from operating activities. See Note 9 of the Notes to Consolidated Financial Statements for more information on our pension plans.

In September 2006, we entered into an agreement to settle our obligation with respect to the U.S. defined benefit plan. Plan assets of approximately $72 million, plus our contribution of $1.5 million, were used to purchase an insurance contract that will be used to fund the benefits and settle the plan. The proposed settlement requires approval from the Pension Benefit Guaranty Corporation and the Internal Revenue Service to relieve us of primary responsibility for the pension benefit obligation. Once regulatory approval is obtained, which is expected in fiscal 2007, we will expense approximately $23.3 million of prepaid pension cost. The $23.3 million asset represents the difference between the amounts we have funded over time and the amount required to be expensed under SFAS No. 87. By relieving us of our obligation, the expense that would have otherwise been recognized over the remaining plan life will be accelerated to the period in which approval is received. As a result of these actions, we have reclassified the pension asset and recorded the payment for the annuity as current assets.

Income Taxes: The effective income tax rates were 31.4%, 30.7%, and 30.7% for the years ended September 30, 2006, 2005, and 2004, respectively. These rates vary primarily due to fluctuations in taxes from the mix of domestic versus foreign income. Deferred tax assets and liabilities are recognized for differences between the book basis and tax basis of the net assets of the Company. In providing for deferred taxes, management considers current tax laws, estimates of future taxable income and available tax planning strategies. This process also involves making forecasts of current and future years' United States taxable income. Unforeseen events and industry conditions may impact these forecasts which in turn can affect the carrying value of deferred tax assets and liabilities and impact our future reported earnings. Our tax filings for various periods are subjected to audit by tax authorities in the jurisdictions where we conduct business. These audits may result in assessments of additional taxes that are resolved with the authorities or potentially through the courts. Resolution of these situations inevitably includes some degree of uncertainty; accordingly, we provide taxes only for the amounts we believe will ultimately result from these proceedings. In addition to the aforementioned assessments that have been received from various taxing authorities, we provide for taxes in certain situations where assessments have not been received. In those situations, we accrue income taxes where we consider it probable that the taxes ultimately payable will exceed those amounts reflected in filed tax returns; accordingly, taxes are provided in those situations under the guidance in SFAS 5.

Self Insurance Accruals and Loss Contingencies: We are self-insured for certain losses relating to workers' compensation, general liability, property damage and employee medical benefits for claims filed and claims incurred but not reported. Management reviews the liability on a quarterly basis. The liability is based primarily on an actuarial undiscounted basis using individual case-based valuations and statistical analysis and is based upon judgment and historical experience; however, the final cost of many of these claims may not be known for five years or longer. This estimate is subject to trends, such as loss development factors, historical average claim volume, average cost for settled claims and current trends in claim costs. Significant and unanticipated changes in these trends or future actual payouts could result in additional increases or decreases to the recorded accruals. We have purchased stop-loss coverage in order to limit, to the extent feasible, our aggregate exposure to certain claims. There is no assurance that such coverage will adequately protect us against liability from all potential consequences.

As discussed in Note 10 of the Notes to Consolidated Financial Statements, legal proceedings covering a wide range of matters are pending or threatened against the Company. It is not possible to predict the outcome of the litigation pending against the Company and litigation is subject to many uncertainties. It is possible that there could be adverse developments in these cases. We record provisions in the consolidated financial statements for pending litigation when we determine that an unfavorable outcome is probable and the amount of the loss can be reasonably estimated. While we believe that our accruals for these matters are adequate, if the actual loss from a loss contingency is significantly different than the estimated loss, our results of operations may be over or understated.

Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)* ("SFAS 158"). This will require companies to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity. It also requires companies to measure the funded status of a plan as of the date of its year-end statement of financial position. Additionally, companies will need to:

a. Recognize the funded status of a benefit plan (measured as the difference between plan assets at fair value (with limited exceptions) and the benefit obligation) in its statement of financial position. For a pension plan, the benefit obligation is the projected benefit obligation; for any other postretirement benefit plan, such as a retiree health care plan, the benefit obligation is the accumulated postretirement benefit obligation.

b. Recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost.

c. Measure defined benefit plan assets and obligations as of the date of the employer's fiscal year-end statement of financial position.

d. Disclose in the notes to financial statements additional information about certain effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and transition asset or obligation.

Recognition of an asset or liability related to the funded status of a pension plan and disclosures are effective for fiscal years ending after December 15, 2006 and the required changes in the measurement date are effective for fiscal years ending after December 15, 2008. We currently measure our defined benefit plan assets and obligations as of our fiscal year-end so, this portion of SFAS 158 will not impact our financial statements. We are currently in the process of evaluating the impact on our financial statements the other requirements of SFAS 158.

In September 2006, the FASB issued SFAS No. 157 ("SFAS 157"), *Fair Value Measurements*, effective for financial statements issued for fiscal years beginning after November 15, 2007. SFAS 157 introduces a new definition of fair value, a fair value hierarchy (requiring market based assumptions be used, if available) and new disclosures of assets and liabilities measured at fair value based on their level in the hierarchy. We are currently in the process of evaluating the impact of SFAS 157 on our financial statements.

In July 2006, the FASB issued Interpretation No. 48 ("FIN 48"), *Accounting for Uncertainty in Income Taxes*, effective for fiscal years beginning after December 15, 2006. FIN 48 prescribes a recognition threshold and measurement attribute, as well as criteria for subsequently recognizing, derecognizing and measuring tax positions for financial statement purposes and requires companies to make disclosures about uncertain income tax positions, including a detailed rollforward of tax benefits taken that do not qualify for financial statement recognition. We are currently in the process of evaluating the impact of FIN 48 on our financial statements.

In May 2005, the FASB issued SFAS 154, *Accounting Changes and Error Corrections*. This is a replacement of APB Opinion No. 20, *Accounting Changes* and SFAS 3, *Reporting Accounting Changes in Interim Financial Statements*. Under SFAS 154, all voluntary changes in accounting principle as well as changes pursuant to accounting pronouncements that do not include specific transition requirements, must be applied retrospectively to prior periods' financial statements. Retrospective application requires the cumulative effect of the change be reflected in the carrying value of assets and liabilities as of the first period presented and the offsetting adjustments are recorded to beginning retained earnings. Each period presented must be adjusted to reflect the period specific effects of applying the change. Also, under SFAS 154, a change in accounting estimate continues to be accounted for in the period of change and in future periods if necessary. Corrections of errors should continue to be reported by restating prior period financial statements as of the beginning of the first period presented, if material. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. We adopted SFAS 154 on October 1, 2006. Adoption did not have a material impact on our financial position and results of operations, since SFAS 154 is to be applied prospectively.

In October 2004, the American Jobs Creation Act of 2004 (the "Act") was signed into law. The Act contains new provisions that may impact our U.S. income tax liability beginning in the current fiscal year. The Act provides a deduction for income from qualified domestic production activities, which will be phased in from 2005 through 2010. Under the guidance in FASB Staff Position No. 109-1, *Application of FASB Statement No. 109, "Accounting for Income Taxes," to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004*, the deduction is treated as a "special deduction" as described in FASB Statement No. 109. As such, the special deduction has no effect on deferred tax assets and liabilities existing at the enactment date. Rather, the impact of this deduction is reported in the period in which the deduction is incurred.

In December 2004, the FASB issued FASB Staff Position No. 109–2 ("FSP 109–2"), *Accounting and Disclosure Guidance for the Foreign Repatriation Provision within the American Jobs Creation Act of 2004*, which provides guidance with respect to recording the potential impact of the repatriation provisions of the Act under SFAS 109 on a company's income tax expense and deferred tax liability. FSP 109–2 states that a company is allowed time beyond the financial reporting period of enactment to evaluate the effect of the Act on its plan for reinvestment or repatriation of foreign earnings for purposes of applying SFAS 109. We have remitted qualifying dividends from our foreign subsidiaries in the amount of $67 million this fiscal year to claim the benefits of this provision of the Act. Furthermore, we believe that any residual U.S. tax liability from this planned repatriation would be fully offset with usable excess foreign tax credits.

Forward Looking Statements

This document contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 and Section 21E of the Securities Exchange Act of 1934 concerning, among other things, our prospects, expected revenue, expenses and profits, developments and business strategies for our operations, all of which are subject to certain risks, uncertainties and assumptions. These forward-looking statements are identified in statements described as "Outlook" and by their use of terms and phrases such as "expect," "estimate," "project," "forecast," "believe," "achievable," "anticipate", "should" and similar terms and phrases. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate under the circumstances. Such statements are subject to:

- fluctuating prices of crude oil and natural gas,
- conditions in the oil and natural gas industry, including drilling activity,
- reduction in prices or demand for our products and services and level of acceptance of price book increases in our markets,
- general global economic and business conditions,
- international political instability, security conditions, hostilities, and declines in customer activity due to adverse local and regional conditions,
- our ability to expand our products and services (including those we acquire) into new geographic markets,
- our ability to generate technological advances and compete on the basis of advanced technology,
- risks from operating hazards such as fire, explosion, blowouts and oil spills,
- litigation for which insurance and customer agreements do not provide protection,
- adverse consequences that may be found in or result from internal investigations, including potential financial and business consequences and governmental actions, proceedings, charges or penalties,
- changes in currency exchange rates,
- severe weather conditions, including hurricanes, that affect conditions in the oil and natural gas industry,
- the business opportunities that may be presented to and pursued by us,
- competition and consolidation in our business,
- changes in law or regulations and other factors, many of which are beyond our control, and
- other risks and uncertainties detailed from time to time in our filings with the Securities and Exchange Commission.

If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, actual results may vary materially from those expected, estimated or projected. Other than as required under securities laws, we do not assume a duty to update these forward looking statements. This list of risk factors is not intended to be comprehensive. See "Risk Factors" included elsewhere in this Annual Report on Form 10-K.

ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk

The table below provides information about our market sensitive financial instruments and constitutes a "forward-looking statement." Our major market risk exposure is to foreign currency fluctuations internationally and changing interest rates, primarily in the United States, Canada and Europe. Our policy is to manage interest rates through use of a combination of fixed and floating rate debt. If the floating rates were to increase by 10% from September 30, 2006 rates, our combined interest expense to third parties would increase by a total of $195 thousand each month in which such increase continued. At September 30, 2006, we had issued fixed-rate debt of $249.7 million, net of discount. These instruments are fixed-rate and, therefore, do not expose us to the risk of loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase by approximately $5.6 million if interest rates were to decline by 10% from their rates at September 30, 2006.

Periodically, we borrow funds which are denominated in foreign currencies, which exposes us to market risk associated with exchange rate movements. There were $0.3 million borrowings denominated in foreign currencies at September 30, 2006. When management believes prudent, we enter into forward foreign exchange contracts to hedge the impact of foreign currency fluctuations. There were no such forward foreign exchange contracts at September 30, 2006. The expected maturity dates and fair value of our market risk sensitive instruments are stated below (in thousands). All items described are non-trading and are stated in U.S. dollars.

	Expected Maturity Dates							Fair Value
	2006	2007	2008	2009	2010	Thereafter	Total	9/30/06
SHORT-TERM BORROWINGS								
Bank borrowings; U.S. $ denominated—average rate 3.88%	$ 274						$ 274	$ 274
Revolving Credit Facility—Average rate 5.95%	160,000						160,000	160,000
LONG-TERM BORROWINGS								
Floating rate Senior Notes due 2008—Average rate 5.57%			250,000				250,000	249,990
5.75% Senior Notes due 2011						249,694	249,694	253,543
Total	**$160,274**	**$—**	**$250,000**	**$—**	**$—**	**$249,694**	**$659,968**	**$663,807**

ITEM 8. Financial Statements and Supplementary Data

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

We are responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined by the Securities and Exchange Act of 1934 Rule 13a-15(f). Our internal controls are designed to provide reasonable assurance as to the reliability of our financial statements for external purposes in accordance with accounting principles generally accepted in the U.S.

Internal control over financial reporting has inherent limitations and may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance, not absolute, assurance with respect to the financial statement preparation and presentation. Further, because of changes in conditions, the effectiveness of internal control over financial reporting may vary over time.

Under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our internal control over financial reporting as of September 30, 2006 as required by the Securities and Exchange Act of 1934 Rule 13a-15(c). In making its assessment, we have utilized the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework.* We concluded that based on our evaluation, our internal control over financial reporting was effective as of September 30, 2006.

Our assessment of the effectiveness of our internal control over financial reporting as of September 30, 2006 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein.

J.W. Stewart
President and Chief Executive Officer

Jeffrey E. Smith
Vice President and Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of BJ Services Company:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that BJ Services Company and subsidiaries (the "Company") maintained effective internal control over financial reporting as of September 30, 2006, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment of the effectiveness of internal control over financial reporting based on our audit.

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

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of September 30, 2006, is fairly stated, in all material respects based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also, in our opinion, the Company maintained in all material respects, effective internal control over financial reporting as of September 30, 2006, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended September 30, 2006 of the Company and our report dated December 7, 2006 expressed an unqualified opinion on those consolidated financial statements and financial statement schedule.

Deloitte & Touche LLP

Houston, Texas
December 7, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of BJ Services Company:

We have audited the accompanying consolidated statements of financial position of BJ Services Company and subsidiaries (the "Company") as of September 30, 2006 and 2005, and the related consolidated statements of operations, stockholders' equity and other comprehensive income, and cash flows for each of the three years in the period ended September 30, 2006. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of BJ Services Company and subsidiaries at September 30, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2006, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of September 30, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated December 7, 2006 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Deloitte & Touche LLP

Houston, Texas
December 7, 2006

BJ SERVICES COMPANY

CONSOLIDATED STATEMENT OF OPERATIONS

	Year Ended September 30,		
	2006	2005	2004
	(in thousands, except per share amounts)		
Revenue	$4,367,864	$3,243,186	$2,600,986
Operating expenses:			
Cost of sales and services	2,895,749	2,334,198	1,951,022
Research and engineering	63,875	54,197	47,287
Marketing	103,319	92,255	82,105
General and administrative	132,011	111,285	78,978
Loss on long-lived assets	1,174	14,192	3,209
Total operating expenses	3,196,128	2,606,127	2,162,601
Operating income	1,171,736	637,059	438,385
Interest expense	(14,558)	(10,951)	(16,389)
Interest income	14,916	11,281	6,073
Other (expense) income, net	(11)	15,958	92,668
Income before income taxes	1,172,083	653,347	520,737
Income tax expense	367,473	200,305	159,696
Net income	$ 804,610	$ 453,042	$ 361,041
Earnings per share:			
Basic	$ 2.55	$ 1.40	$ 1.13
Diluted	$ 2.52	$ 1.38	$ 1.10
Weighted average shares outstanding:			
Basic	315,022	323,763	320,358
Diluted	318,820	329,115	326,828

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

BJ SERVICES COMPANY

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

ASSETS

	As of September 30, 2006	As of September 30, 2005
	(in thousands)	
Current assets:		
Cash and cash equivalents	$ 92,445	$ 356,508
Receivables, less allowance for doubtful accounts: 2006, $18,976; 2005, $13,938	927,027	695,359
Inventories:		
Products	185,249	151,641
Work-in-progress	27,308	7,545
Parts	143,347	75,905
Total inventories	355,904	235,091
Deferred income taxes	5,103	16,107
Prepaid expenses	36,311	21,667
Other current assets	42,070	12,250
Total current assets	1,458,860	1,336,982
Property:		
Land	26,573	17,339
Buildings and other	317,337	269,191
Machinery and equipment	2,232,240	1,712,366
Total property	2,576,150	1,998,896
Less accumulated depreciation	1,183,224	911,964
Property, net	1,392,926	1,086,932
Goodwill	928,297	885,212
Deferred income taxes	29,557	24,140
Investments and other assets	52,648	76,376
Total assets	$3,862,288	$3,409,642

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

LIABILITIES AND STOCKHOLDERS' EQUITY

	As of September 30, 2006	2005
	(in thousands, except shares)	
Current liabilities:		
Accounts payable, trade	$ 435,040	$ 326,632
Short-term borrowings	160,274	3,390
Current portion of long-term debt	—	78,984
Accrued employee compensation and benefits	131,725	104,962
Income taxes	60,160	36,568
Deferred income taxes	327	197
Taxes other than income	25,385	22,679
Accrued insurance	19,051	19,343
Other accrued liabilities	115,974	93,549
Total current liabilities	947,936	686,304
Long-term debt	499,694	—
Deferred income taxes	66,584	66,958
Accrued postretirement benefits	54,296	48,561
Other long-term liabilities	146,838	115,778
Commitments and contingencies (Note 10)		
Stockholders' equity:		
Preferred stock (authorized 5,000,000 shares, none issued)		
Common stock, $.10 par value (authorized 910,000,00 shares; 347,510,648 shares issued and 293,193,764 outstanding in 2006; 347,510,648 shares issued and 323,410,991 outstanding in 2005)	34,752	34,752
Capital in excess of par	1,028,813	1,016,333
Retained earnings	2,494,350	1,747,445
Accumulated other comprehensive income	22,833	24,371
Unearned compensation	—	(9,195)
Treasury stock, at cost (2006 – 54,316,884 shares; 2005 – 24,099,657 shares)	(1,433,808)	(321,665)
Total stockholders' equity	2,146,940	2,492,041
Total liabilities and stockholders' equity	$ 3,862,288	$3,409,642

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

BJ SERVICES COMPANY

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY AND OTHER COMPREHENSIVE INCOME
(in thousands)

	Common Stock Shares	Common Stock	Capital In Excess of Par	Treasury Stock	Unearned Compe-nsation	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance, September 30, 2003, as reported	**316,612**	**$34,752**	**$ 964,348**	**$ (348,277)**	**$ —**	**$1,009,456**	**$ (9,647)**	**$ 1,650,632**
Step acquisition of BJSP (Note 3)						8,288		8,288
Balance, September 30, 2003, as restated	**316,612**	**$34,752**	**$ 964,348**	**$ (348,277)**	**$ —**	**$1,017,744**	**$ (9,647)**	**$ 1,658,920**
Comprehensive income:								
Net income						361,041		
Other comprehensive income, net of tax:								
Cumulative translation adjustments							10,468	
Minimum pension liability adjustment							(1,729)	
Comprehensive income								369,780
Dividend declared						(12,935)		(12,935)
Reissuance of treasury stock for:								
Stock option plan	5,946			66,566		(17,304)		49,262
Stock purchase plan	990			11,157		(217)		10,940
Stock incentive plan	190		(3,103)	2,144		898		(61)
Stock incentive plan grant			7,273		(7,273)			—
Recognition of unearned compensation					3,772			3,772
Revaluation of stock incentive plan awards			3,460		(3,460)			—
Tax benefit from exercise of options			22,746					22,746
Balance, September 30, 2004	**323,738**	**$34,752**	**$ 994,724**	**$ (268,410)**	**$(6,961)**	**$1,349,227**	**$ (908)**	**$ 2,102,424**
Comprehensive income:								
Net income						453,042		
Other comprehensive income, net of tax:								
Cumulative translation adjustments							11,482	
Minimum pension liability adjustment							13,797	
Comprehensive income								478,321
Dividends declared						(55,005)		(55,005)
Treasury stock purchase	(3,982)			(98,360)				(98,360)
Reissuance of treasury stock for:								
Stock option plan	2,809			35,461		(2,447)		33,014
Stock purchase plan	836			9,523		2,628		12,151
Director stock award	10		(121)	121				—
Stock incentive plan grant			6,468		(6,468)			—
Director stock award grant expense			874					874
Recognition of unearned compensation					7,807			7,807
Revaluation of stock incentive plan awards			3,573		(3,573)			—
Tax benefit from exercise of options			10,815					10,815
Balance, September 30, 2005	**323,411**	**$34,752**	**$1,016,333**	**$ (321,665)**	**$(9,195)**	**$1,747,445**	**$ 24,371**	**$ 2,492,041**
Comprehensive income:								
Net income						804,610		
Other comprehensive income, net of tax:								
Cumulative translation adjustments							9,511	
Minimum pension liability adjustment							(11,049)	
Comprehensive income								803,072
Dividends declared						(63,272)		(63,272)
Treasury stock purchase	(31,726)			(1,133,313)				(1,133,313)
Reissuance of treasury stock for:								
Stock option plan	911			13,180		454		13,634
Stock purchase plan	572			7,635		5,113		12,748
Director stock award	26		(355)	355				—
Stock based compensation			21,397					21,397
Adoption of SFAS 123(R) (Note 13)			(9,195)		9,195			—
Tax benefit from exercise of options			633					633
Balance, September 30, 2006	**293,194**	**$34,752**	**$1,028,813**	**$(1,433,808)**	**$ —**	**$2,494,350**	**$ 22,833**	**$ 2,146,940**

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

BJ SERVICES COMPANY

CONSOLIDATED STATEMENT OF CASH FLOWS

	Year Ended September 30,		
	2006	2005	2004
	(in thousands)		
Cash flows from operating activities:			
Net income	$ 804,610	$ 453,042	$ 361,041
Adjustments to reconcile net income to cash provided from operating activities:			
Depreciation	166,763	136,861	125,668
Net loss on long-lived assets	1,174	14,192	3,209
Excess tax benefits from stock compensation	(3,419)	—	—
Recognition of unearned compensation	—	8,681	3,772
Deferred income tax expense (benefit)	6,024	(7,111)	109,775
Minority interest expense	3,970	3,725	2,286
Changes in:			
Receivables	(215,020)	(154,677)	(78,042)
Accounts payable, trade	105,833	81,756	31,509
Inventories	(111,189)	(53,161)	(20,975)
Employee compensation and benefits	26,763	26,913	8,844
Current income tax	34,726	(7,611)	(31,509)
Other current assets	(20,561)	12,456	(7,411)
Other current liabilities	17,612	(979)	577
Other, net	15,168	31,618	19,863
Net cash flows provided from operating activities	832,454	545,705	528,607
Cash flows from investing activities:			
Property additions	(459,974)	(323,763)	(200,577)
Proceeds from disposal of assets	8,932	7,834	2,149
Proceeds (purchases) of U.S. Treasury securities	—	229,774	(229,930)
Acquisitions of businesses, net of cash acquired	(52,172)	—	(15,337)
Net cash used for investing activities	(503,214)	(86,155)	(443,695)
Cash flows from financing activities:			
Proceeds from exercise of stock options and stock purchase plan	26,142	45,165	61,413
Purchase treasury stock	(1,133,313)	(98,360)	—
Proceeds from long-term debt	499,673	—	—
Repayment of long-term debt	(79,000)	(422,369)	—
(Repayment) proceeds of short-term borrowings, net	156,884	(364)	(2,134)
Dividends paid to shareholders	(64,338)	(51,855)	—
Excess tax benefits from stock compensation	3,419	—	—
Debt issuance costs	(2,824)	—	(1,042)
Net cash flows provided from/(used in) financing activities	(593,357)	(527,783)	58,237
Effect of exchange rate changes on cash	54	16	3,910
(Decrease) increase in cash and cash equivalents	(264,063)	(68,217)	147,059
Cash and cash equivalents at beginning of year	356,508	424,725	277,666
Cash and cash equivalents at end of year	$ 92,445	$ 356,508	$ 424,725

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

BJ SERVICES COMPANY

Notes to the Consolidated Financial Statements

1. Business and Basis of Presentation

BJ Services Company (the "Company"), whose operations trace back to the Byron Jackson Company (which was founded in 1872), was organized in 1990 under the corporate laws of the state of Delaware. We are a leading worldwide provider of pressure pumping and other oilfield services for the petroleum industry. Our pressure pumping services consist of cementing and stimulation services used in the completion of new oil and natural gas wells and in remedial work on existing wells, both onshore and offshore. The Oilfield Services Group includes completion tools, completion fluids and casing and tubular services provided to the oil and natural gas exploration and production industry, commissioning and inspection services provided to refineries, pipelines and offshore platforms, and production chemical services.

We consolidate all investments in which we own greater than 50%, or in which we control. All material intercompany balances and transactions are eliminated in consolidation. Investments in companies in which our ownership interest ranges from 20% to 50% and we exercise significant influence over operating and financial policies are accounted for using the equity method. Other investments are accounted for using the cost method.

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

Share and earnings per share amounts have been restated for all periods presented to reflect the increased number of common shares outstanding resulting from the 2-for-1 stock split payable on September 1, 2005 to stockholders of record as of August 18, 2005.

Certain amounts for 2005 and 2004 have been reclassified in the accompanying consolidated financial statements to conform to the current year presentation.

2. Summary of Significant Accounting Policies

Cash and cash equivalents: We consider all highly liquid investments purchased with original maturities of three months or less at the time of purchase to be cash equivalents.

Allowance for doubtful accounts: We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer's current credit worthiness, as determined by our review of their available credit information. We continuously monitor collections and payments from our customers and maintain a provision for estimated uncollectible accounts based upon our historical experience and any specific customer collection issues that we have identified. While such credit losses have historically been within our expectations and the provisions established, we cannot give any assurances that we will continue to experience the same credit loss rates that we have in the past. The cyclical nature of our industry may affect our customers' operating performance and cash flows, which could impact our ability to collect on these obligations. In addition, many of our customers are located in certain international areas that are inherently subject to risks of economic, political and civil instabilities, which may impact our ability to collect these receivables.

Inventories: Inventories, which consist principally of (i) products which are consumed in our services provided to customers, (ii) spare parts for equipment used in providing these services and (iii) manufactured components and attachments for equipment used in providing services, are stated primarily at the lower of weighted-average cost or market. Cost primarily represents invoiced costs. We regularly review inventory quantities on hand and record provisions for excess or obsolete inventory based primarily on our estimated forecast of product demand, market conditions, production requirements and technological developments. Significant or unanticipated changes in market condition or to our forecast could require additional provisions for excess or obsolete inventory.

Property: Property is stated at cost less amounts provided for permanent impairments and includes capitalized interest of $2.0 million, $1.2 million, and $0.8 million for the years ended September 30, 2006, 2005 and 2004, respectively. Depreciation is generally provided using the straight-line method over the estimated useful lives of individual items. Leasehold improvements are amortized on a straight-line basis over the shorter of their estimated useful lives or the lease terms. The estimated useful lives are 10 to 30 years for buildings and leasehold improvements and range from 3 to 12 years for machinery and equipment. We make judgments and estimates in conjunction with the carrying value of these assets, including amounts to be capitalized, depreciation and amortization methods and useful lives. Additionally, the carrying values of these assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. The determination of recoverability is made based upon estimated undiscounted future cash flows. An impairment loss is recorded in the period in which it is determined that the carrying amount is not recoverable. The amount of the impairment, if any, is the amount by which the net book value of the asset exceeds fair value. Fair value determination requires us to make long-term forecasts of future revenue and costs related to the assets subject to review. These forecasts require assumptions about demand for our products and services, future market conditions and technological developments. Significant and unanticipated changes to these assumptions could require a provision for impairment in a future period. Rig count has experienced double digit growth over the last three years. As such, substantially all of our equipment that can perform is currently working. In fiscal 2005, it was determined that certain equipment that was not able to operate would be written down to the fair value of the usable major components. The fair value of these assets was based on market prices for the same, or similar assets. In fiscal 2005, we recorded an $11.7 million impairment during our fourth fiscal quarter of 2005, related to idle assets. This impairment is reflected in the Corporate results.

Intangible assets: Goodwill represents the excess of cost over the fair value of the net assets of companies acquired in purchase transactions. We account for goodwill in accordance with Statement of Financial Accounting Standards ("SFAS") 142, *Goodwill and Other Intangible Assets* which requires goodwill to be reviewed for possible impairment on an annual basis, or if circumstances indicate that an impairment may exist. We performed our annual evaluation as of September 30 and concluded that an impairment adjustment was not necessary to our goodwill balance at September 30, 2006 and 2005, respectively. Other intangible assets primarily consist of technology based intangible assets and are being amortized on a straight-line basis ranging from 5 to 20 years, with the weighted average amortization period being 17.7 years. We utilize undiscounted estimated cash flows to evaluate any possible impairment of intangible assets. If such cash flows are less than the net carrying value of the intangible assets, we would record an impairment loss equal to the difference in discounted estimated cash flows and the net carrying value. The discount rate utilized is based on market factors at the time the loss is determined.

Income Taxes: We provide for income taxes in accordance with SFAS 109, *Accounting for Income Taxes*. This standard takes into account the differences between financial statement treatment and tax treatment of certain transactions. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates is recognized as income or expense in the period that includes the enactment date. This calculation requires us to make certain estimates about our future operations. Changes in state, federal and foreign tax laws as well as changes in our financial condition could affect these estimates. We record a valuation allowance to reduce our deferred tax assets when it is more likely than not that some portion or all of the deferred tax assets will not be utilized. We consider all available evidence, both positive and negative, to determine whether a valuation allowance is needed. The ultimate realization of the deferred tax assets depends on the ability to generate sufficient taxable income of the appropriate character within the carryback or carryforward period set forth under the applicable tax law. Our tax filings for various periods are subjected to audit by tax authorities in the jurisdictions where we conduct business. These audits may result in assessments of additional taxes that are resolved with the authorities or potentially through the courts. Resolution of these situations inevitably includes some degree of uncertainty; accordingly, we provide taxes only for the amounts we believe will ultimately result from these proceedings. In addition to the aforementioned assessments that have been received from various taxing authorities, we provide for taxes in certain situations where assessments have not been received. In those situations, we accrue income taxes where we consider it probable that the taxes ultimately payable will exceed those amounts reflected in filed tax returns; accordingly, taxes are provided in those situations under the guidance in SFAS 5, *Accounting for Contingencies*.

Self Insurance Accruals: We are self-insured for certain losses relating to workers' compensation, general liability, property damage and employee medical benefits for claims filed and claims incurred but not reported. Our liability is based primarily on an actuarial undiscounted basis using individual case-based valuations and statistical analysis and is based upon judgment and historical experience; however, the final cost of many of these claims may not be known for five years or longer. Management reviews the reserve on a quarterly basis. Changes in claims experience, health care costs, etc. could affect these estimates.

Contingencies: Contingencies are accounted for in accordance with SFAS 5. This standard requires that we record an estimated loss from a loss contingency when information available prior to the issuance of our financial statements indicates that it is probable that an asset has been impaired or a liability has been incurred at the date of the financial statements and the amount of the loss can be reasonably estimated. Accounting for contingencies such as environmental, legal, and income tax matters requires us to use judgment. While we believe that our accruals for these matters are adequate, if the actual loss from a loss contingency is significantly different than the estimated loss, our results of operations may be adversely impacted. For significant litigation, we accrue for our legal costs.

Environmental remediation and compliance: Environmental remediation costs are accrued based on estimates of known environmental exposures using currently available facts, existing environmental permits and technology and presently enacted laws and regulations. For sites where we are primarily responsible for the remediation, our estimate of costs are developed based on internal evaluations and are not discounted. Such accruals are recorded when environmental assessments and/or remedial efforts are probable and the cost can be reasonably estimated. The accrual is recorded even if significant uncertainties exist over the ultimate cost of the remediation and is updated as additional information becomes available. Ongoing environmental compliance costs, such as obtaining environmental permits, installation of pollution control equipment and waste disposal, are expensed as incurred. Where we have been identified as a potentially responsible party in a U.S. federal or state Superfund site, we accrue our share of the estimated remediation costs of the site based on the ratio of the estimated volume of waste contributed to the site by us to the total estimated volume of waste at the site.

Revenue Recognition: Our revenue is composed of product sales, rental, service and other revenue. Products, rentals, and services are generally sold based on fixed or determinable priced purchase orders or contracts with the customer and do not include the right of return. We recognize revenue from product sales when title passes to the customer, the customer assumes risks and rewards of ownership, and collectibility is reasonably assured. Rental, service and other revenue is recognized when the services are provided and collectibility is reasonably assured.

Research and development expenditures: Research and development expenditures are expensed as incurred.

Maintenance and repairs: Expenditures for maintenance and repairs are expensed as incurred. Expenditures for renewals and improvements are capitalized if they extend the life, increase the capacity, or improve the efficiency of the asset.

Foreign currency translation: Our functional currency is primarily the U.S. dollar. Gains and losses resulting from financial statement translation of foreign operations where a foreign currency is the functional currency are included as a separate component of stockholders' equity. Our operation in Canada, Hungary and Algeria use their respective local currencies as the functional currency.

Derivative instruments: We occasionally enter into forward foreign exchange contracts to hedge the impact of currency fluctuations on certain transactions and assets and liabilities denominated in foreign currencies. We do not enter into derivative instruments for speculative or trading purposes. SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, requires that we recognize all derivatives on the balance sheet at fair value. We record derivative transactions in accordance with SFAS 133.

Employee stock-based compensation: Beginning October 1, 2005, employee services received in exchange for stock are expensed in accordance with SFAS 123(R), *Share-Based Payment*. The fair value of the employee services received in exchange for stock is measured based on the grant-date fair value. The fair value is determined using the Black-Scholes option-pricing model for the stock option awards and a Monte-Carlo simulation model for the stock incentive awards. Awards granted are expensed pro-ratably over the vesting period of the award. As stock based compensation expense is recognized based on awards ultimately expected to vest ,we have therefore reduced the expense for estimated forfeitures based on historical forfeiture rates. SFAS 123(R) requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods to reflect actual forfeitures.

Prior to October 1, 2005 we had adopted the disclosure-only provisions of SFAS 123 and accounted for substantially all of its stock-based compensation using the intrinsic value method prescribed in APB 25. Under APB 25, no compensation expense was recognized for stock options or the stock purchase plan. Compensation expense was recognized for the stock incentive awards and director stock awards. See Note 13 for additional information.

New accounting pronouncements: In September 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)* ("SFAS 158"). This will require companies to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity. It also requires companies to measure the funded status of a plan as of the date of its year-end statement of financial position. Additionally, companies will need to:

a. Recognize the funded status of a benefit plan (measured as the difference between plan assets at fair value (with limited exceptions) and the benefit obligation) in its statement of financial position. For a pension plan, the benefit obligation is the projected benefit obligation; for any other postretirement benefit plan, such as a retiree health care plan, the benefit obligation is the accumulated postretirement benefit obligation.

b. Recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost.

c. Measure defined benefit plan assets and obligations as of the date of the employer's fiscal year-end statement of financial position.

d. Disclose in the notes to financial statements additional information about certain effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and transition asset or obligation.

Recognition of an asset or liability related to the funded status of a pension plan and disclosures are effective for fiscal years ending after December 15, 2006 and the required changes in the measurement date are effective for fiscal years ending after December 15, 2008. We currently measure our defined benefit plan assets and obligations as of our fiscal year-end so, this portion of SFAS 158 will not impact our financial statements. We are currently in the process of evaluating the impact on our financial statements the other requirements of SFAS 158.

In September 2006, the FASB issued SFAS No. 157 ("SFAS 157"), *Fair Value Measurements*, effective for financial statements issued for fiscal years beginning after November 15, 2007. SFAS 157 introduces a new definition of fair value, a fair value hierarchy (requiring market based assumptions be used, if available) and new disclosures of assets and liabilities measured at fair value based on their level in the hierarchy. We are currently in the process of evaluating the impact of SFAS 157 on our financial statements.

In July 2006, the FASB issued Interpretation No. 48 ("FIN 48"), *Accounting for Uncertainty in Income Taxes*, effective for fiscal years beginning after December 15, 2006. FIN 48 prescribes a recognition threshold and measurement attribute, as well as criteria for subsequently recognizing, derecognizing and measuring tax positions for financial statement purposes and requires companies to make disclosures about uncertain income tax positions, including a detailed rollforward of tax benefits taken that do not qualify for financial statement recognition. We are currently in the process of evaluating the impact of FIN 48 on our financial statements.

In May 2005, the FASB issued SFAS 154, *Accounting Changes and Error Corrections*. This is a replacement of APB Opinion No. 20, *Accounting Changes* and SFAS 3, *Reporting Accounting Changes in Interim Financial Statements*. Under SFAS 154, all voluntary changes in accounting principle as well as changes pursuant to accounting pronouncements that do not include specific transition requirements, must be applied retrospectively to prior periods' financial statements. Retrospective application requires the cumulative effect of the change be reflected in the carrying value of assets and liabilities as of the first period presented and the offsetting adjustments are recorded to beginning retained earnings. Each period presented must be adjusted to reflect the period specific effects of applying the change. Also, under SFAS 154, a change in accounting estimate continues to be accounted for in the period of change and in future periods if necessary. Corrections of errors should continue to be reported by restating prior period financial statements as of the beginning of the first period presented, if material. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. We adopted SFAS 154 on October 1, 2006. Adoption did not have a material impact on our financial position and results of operations, since SFAS 154 is to be applied prospectively.

In October 2004, the American Jobs Creation Act of 2004 (the "Act") was signed into law. The Act contains new provisions that may impact our U.S. income tax liability beginning in the current fiscal year. The Act provides a deduction for income from qualified domestic production activities, which will be phased in from 2005 through 2010. Under the guidance in FASB Staff Position No. 109-1, *Application of FASB Statement No. 109, "Accounting for Income Taxes," to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004*, the deduction is treated as a "special deduction" as described in FASB Statement No. 109. As such, the special deduction has no effect on deferred tax assets and liabilities existing at the enactment date. Rather, the impact of this deduction is reported in the period in which the deduction is incurred.

In December 2004, the FASB issued FASB Staff Position No. 109–2 ("FSP 109–2"), *Accounting and Disclosure Guidance for the Foreign Repatriation Provision within the American Jobs Creation Act of 2004*, which provides guidance with respect to recording the potential impact of the repatriation provisions of the Act under SFAS 109 on a company's income tax expense and deferred tax liability. FSP 109–2 states that a company is allowed time beyond the financial reporting period of enactment to evaluate the effect of the Act on its plan for reinvestment or repatriation of foreign earnings for purposes of applying SFAS 109. We have remitted qualifying dividends from our foreign subsidiaries in the amount of $67 million this fiscal year to claim the benefits of this provision of the Act. Furthermore, we believe that any residual U.S. tax liability from this planned repatriation would be fully offset with our usable excess foreign tax credits.

3. Acquisitions of Businesses

On June 25, 2006, we acquired an additional 2% interest in our Algerian joint venture, Societe Algerienne de Stimulation de Puits Productures d'Hydrocarbures ("BJSP"), for $4.6 million, increasing our total ownership in BJSP to 51%. L'Enterprise de Services aux Puits ("ENSP"), an indirect subsidiary of Sonatrach, owns the remaining 49%. BJSP provides coiled tubing and cementing services to the Algerian market. Prior to obtaining controlling interest in BJSP, we accounted for the investment using the cost method, as we could not exercise significant influence over the entity. Following this transaction, which is being accounted for as a step-acquisition, we have control of BJSP and now consolidate the entity. In accordance with APB 18, *Equity Method of Accounting of Investments in Common Stock*, and ARB 51, *Consolidated Financial Statements*, we have retroactively adjusted beginning retained earnings to adopt the equity method of accounting for our ownership interest in previous periods. This adjustment resulted in a $8.3 million increase to beginning retained earnings as reflected in the consolidated statement of stockholders' equity and other comprehensive income. The statement of operations has not been restated as the impact of adopting the equity method was not material in any given period.

Following the transaction, the assets and liabilities and results of operations of BJSP are included in our consolidated results, in the International Pressure Pumping segment. The consolidation resulted in an increase of $42.4 million in total current assets (including approximately $14.1 million in cash), $12.1 million in total current liabilities, $19.3 million in minority interest and $0.2 million in goodwill. We are in the process of completing our purchase price allocation for this step acquisition. The pro forma financial information for this acquisition is not included as it is not material to our consolidated financial statements.

On August 15, 2006, we purchased substantially all of the operating assets of Dyna Coil of South Texas, Ltd., Dyna Coil Injection Systems, Inc. and Dynochem, Ltd. (collectively, "Dyna-Coil") for $61.7 million in cash. Dyna-Coil is focused on production optimization services, particularly the installation and service of capillary injection systems and associated products (production chemicals) mostly in the U.S. and Canada and is included in our production chemicals business in the Oilfield Services segment. The acquisition resulted in an increase of $8.2 million in total current assets, $3.4 million in property and equipment, $7.1 million of technology based intangibles and $42.9 million in goodwill. We are in the process of completing our purchase price allocation. The pro forma financial information for this acquisition is not included as it is not material to our consolidated financial statements.

4. Earnings Per Share

Basic EPS excludes dilution and is computed by dividing net income by the weighted-average number of common shares outstanding for the period. Diluted EPS is based on the weighted-average number of shares outstanding during each period and the assumed exercise of dilutive instruments (stock options, employee stock purchase plan, stock incentive awards, and director stock awards) less the number of treasury shares assumed to be purchased with the exercise proceeds using the average market price of our common stock for each of the periods presented.

The following table presents information necessary to calculate earnings per share for the three years ended September 30, 2006 (in thousands, except per share amounts):

	2006	2005	2004
Net Income	$804,610	$453,042	$361,041
Weighted-average common shares outstanding	315,022	323,763	320,358
Basic earnings per share	$ 2.55	$ 1.40	$ 1.13
Weighted-average common and dilutive potential common shares outstanding:			
Weighted-average common shares outstanding	315,022	323,763	320,358
Assumed exercise of stock options[1]	3,798	5,352	6,470
Weighted-average dilutive shares outstanding	318,820	329,115	326,828
Diluted earnings per share	$ 2.52	$ 1.38	$ 1.10

[1] For the years ended September 30, 2006, 2005 and 2004, respectively, no stock options were excluded from the computation of diluted earnings per share due to their antidilutive effect.

In November 2006, we granted 1,702,045 shares for stock options and 144,000 for director stock awards and have reserved 774,911 shares for the employee stock purchase plan and 113,180 units for stock incentive awards,. See Note 13 for further information of the terms and conditions of these plans.

5. Debt

Long term debt at September 30 consisted of the following (in thousands):

	2006	2005
7% Series B Notes due February 1, 2006, net of discount	$ —	$ 78,984
Floating rate Senior Notes due 2008	250,000	—
5.75% Senior Notes due 2011, net of discount	249,694	—
	499,694	78,984
Less current maturities of long-term debt	—	(78,984)
Long term debt	$499,694	$ —

On June 8, 2006, we completed a public offering of $500.0 million aggregate principal amount of Senior Notes, consisting of $250.0 million of floating rate Senior Notes due 2008, with an annual interest rate of three-month LIBOR plus 17 basis points, and $250.0 million of 5.75% Senior Notes due 2011. The net proceeds from the offering of approximately $497.1 million, after deducting underwriting discounts and commissions and expenses, were used primarily to repurchase outstanding shares of common stock and also repay indebtedness, fund capital expenditures and for other corporate purposes. As of September 30, 2006, we had $250.0 million of the Senior Notes due 2008 issued and outstanding and $249.7 million, net of discount, of the 5.75% Senior Notes due 2011 issued and outstanding.

In June 2004, we replaced our then existing credit facility with a revolving credit facility (the "Revolving Credit Facility") that permits borrowings up to $400 million in principal amount. The Revolving Credit Facility includes a $50 million sublimit for the issuance of standby letters of credit and a $20 million sublimit for swingline loans. Swingline loans have short-term maturities and the remaining amounts outstanding under the Revolving Credit Facility become due and payable in June 2009. Interest on outstanding borrowings is charged based on prevailing market rates. We are charged various fees in connection with the Revolving Credit Facility, including a commitment fee based on the average daily unused portion of the commitment, totaling $0.5 million in fiscal 2006 and 2005. In addition, the Revolving Credit Facility charges a utilization fee on all outstanding loans and letters of credit when usage of the Revolving Credit Facility exceeds 33%, though there were no such charges in fiscal 2005, and no material fees in fiscal 2006. At September 30, 2006, there was $160.0 million outstanding. There were no outstanding borrowings under the Revolving Credit Facility at September 30, 2005.

In addition to the Revolving Credit Facility, we had $64.4 million of unsecured, discretionary lines of credit at September 30, 2006, which expire at the bank's discretion. There are no requirements for commitment fees or compensating balances in connection with these lines of credit and interest is at prevailing market rates. There was $0.3 million and $3.4 million in outstanding borrowings under these lines of credit at September 30, 2006 and 2005, respectively. The weighted average interest rates on short-term borrowings outstanding as of September 30, 2006 and 2005 were 5.95% and 7.75%, respectively.

At September 30, 2005, we had issued and outstanding $79.0 million of unsecured 7% Series B Notes due February 1, 2006, net of discount. We repaid this debt obligation with available cash on the maturity date, February 1, 2006.

The Senior Notes and Revolving Credit Facility include various customary covenants and other provisions, including the maintenance of certain profitability and solvency ratios, none of which materially restrict the our activities. We are currently in compliance with all covenants imposed.

6. Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable.

Cash and Cash Equivalents, Short-term Investments, Trade Receivables, Trade Payables and Short-Term Borrowings: The carrying amount approximates fair value because of the short maturity of those instruments.

Long-term Debt: Fair value is based on the rates currently available to us for debt with similar terms and average maturities.

Foreign Exchange Contracts: Periodically, we borrow funds which are denominated in foreign currencies, which exposes us to market risk associated with exchange rate movements. There were $0.3 million borrowings denominated in foreign currencies at September 30, 2006 and no such borrowings at September 30, 2005.

The fair value of financial instruments that differed from their carrying value at September 30, 2006 and 2005 was as follows (in thousands):

	2006		2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Floating rate Senior Notes due 2008	$250,000	$249,990	$ —	$ —
5.75% Senior Notes due 2011	249,694	253,543	—	—
7% Series B Notes	—	—	78,984	79,637

7. Income Taxes

The geographical sources of income before income taxes for the three years ended September 30 were as follows (in thousands):

	2006	2005	2004
United States	$ 848,586	$425,399	$342,983
Foreign	323,497	227,948	177,754
Income before income taxes	$1,172,083	$653,347	$520,737

The provision for income taxes for the three years ended September 30 is summarized below (in thousands):

	2006	2005	2004
Current:			
United States	$281,579	$130,088	$ 29,387
Foreign	79,870	77,328	20,534
Total current	361,449	207,416	49,921
Deferred:			
United States	8,263	9,587	81,368
Foreign	(2,239)	(16,698)	28,407
Total deferred	6,024	(7,111)	109,775
Income tax expense	$367,473	$200,305	$159,696

The consolidated effective income tax rates (as a percent of income (loss) before income taxes) for the three years ended September 30, 2005 varied from the United States statutory income tax rate for the reasons set forth below:

	2006	2005	2004
Statutory rate	35.0%	35.0%	35.0%
Foreign earnings at varying rates	(2.9)	(3.6)	(3.2)
State income taxes, net of federal benefit	0.8	0.6	0.3
Other income taxes	0.7	1.1	—
Changes in valuation reserve	0.3	0.5	—
Foreign income recognized domestically	6.9	9.7	1.4
Foreign expense recognized domestically	(1.4)	—	—
Dividends received deduction	(1.7)	—	—
Domestic production activity	(0.7)	—	—
Amortization	—	(0.2)	—
Tax credits	(5.9)	(12.3)	(3.4)
Nondeductible expenses	0.8	0.5	0.1
Other, net	(0.5)	(0.6)	0.5
	31.4%	30.7%	30.7%

Deferred tax assets and liabilities are recognized for the estimated future tax effects of temporary differences between the tax basis of assets or liabilities and its reported amount in the financial statements. The measurement of deferred tax assets and liabilities is based on enacted tax laws and rules currently in effect in each of the taxing jurisdictions in which we have operations. Generally, deferred tax assets and liabilities are classified as current or noncurrent according to the classification of the related asset or liability for financial reporting. The estimated deferred tax effect of temporary differences and carryforwards as of September 30 were as follows (in thousands):

	2006	2005
Assets:		
Accrued compensation expense	$ 11,333	$ 12,368
Accrued postretirement benefits	19,882	17,843
Pension liability	14,042	7,975
Deferred gain[1]	6,467	9,386
Accrued insurance expense	7,790	6,701
Other accrued expenses	28,737	20,509
Foreign tax credit carryforwards	37,211	26,287
Net operating and capital loss carryforwards	18,934	18,578
Valuation allowance	(45,013)	(31,062)
Total deferred tax asset	$ 99,383	$ 88,585
Liabilities		
Differences in depreciable basis of property	$(111,992)	$ (97,679)
Unrealized gain/loss	(8,771)	(7,604)
Pension asset	(8,526)	(7,342)
Earnings of foreign affiliates	(2,345)	(2,345)
Income accrued for financial reporting purposes, not yet reported for tax	—	(523)
Total deferred tax liability	(131,634)	(115,493)
Net deferred tax liability	$ (32,251)	$ (26,908)

[1] Deferred gain on the contribution of pumping service equipment to the partnerships referred to in Note 10.

At September 30, 2006, we had approximately $57.6 million of foreign net operating loss carryforwards and $20.4 million of state net operating loss carryforwards. The foreign net operating loss carryforwards expire as follows: $13.9 million by fiscal year 2016 and the remaining $43.7 million does not expire. The state net operating losses will expire between fiscal year 2007 and fiscal year 2018. We also had $37.2 million of U.S. foreign tax credit carryforwards. Substantially all of these US foreign tax credits expire in 2012. The tax impact of the net operating loss and foreign tax credit carryforwards that are more likely than not to expire before realization of the benefit is reflected in the valuation allowance balance as of September 30, 2006.

We record a valuation allowance to reduce our deferred tax assets when it is more likely than not that some portion or all of the deferred tax assets will expire before realization of the benefit. Because management believes that it is more likely than not that a portion of the foreign net operating loss carry forwards and the U.S. foreign tax credits will not be realized, a valuation allowance has been recorded on these amounts. Furthermore, with respect to this valuation allowance, approximately $2.8 million of such valuation allowance, if subsequently realized, will be allocated to reduce goodwill.

Our stock basis difference in foreign subsidiaries, for which a U.S. deferred tax liability has not been established, is approximately $281 million as of September 30, 2006. This stock basis difference arises from the existence of unremitted foreign earnings and cumulative translation adjustments. We have provided additional taxes for the anticipated repatriation of foreign earnings of our foreign subsidiaries where we have determined that the foreign subsidiaries earnings are not indefinitely reinvested. For foreign subsidiaries whose earnings are indefinitely reinvested, no provision for U.S. federal and state income taxes has been provided. If we were to record a tax liability for the full tax versus book basis difference of its foreign subsidiaries, an additional net deferred tax liability of approximately $18.6 million would be necessary.

8. Segment Information

We currently have thirteen operating segments for which separate financial information is available and that have separate management teams that are engaged in oilfield services. The results for these operating segments are evaluated regularly by the chief operating decision maker in deciding how to allocate resources and assessing performance. The operating segments have been aggregated into four reportable segments: U.S./Mexico Pressure Pumping, International Pressure Pumping, Canada Pressure Pumping and the Oilfield Services Group. Canada Pressure Pumping was added as a segment in fiscal 2006, and as a result, International Pressure Pumping has been recast to reflect this change.

The U.S./Mexico Pressure Pumping has two operating segments and includes cementing services and stimulation services (consisting of fracturing, acidizing, sand control, nitrogen, coiled tubing and service tool services) provided throughout the United States and Mexico. These two operating segments have been aggregated into one reportable segment because they offer the same type of services, have similar economic characteristics, have similar production processes and use the same methods to provide their services.

The International Pressure Pumping segment has five operating segments. Similar to U.S./Mexico Pressure Pumping, it includes cementing and stimulation services (consisting of fracturing, acidizing, sand control, nitrogen, coiled tubing and service tool services). These services are provided to customers in more than 50 countries in the major international oil and natural gas producing areas of Latin America, Europe and Africa, Asia Pacific, Russia and the Middle East. The operating segments have been aggregated into one reportable segment because they have similar economic characteristics, offer the same type of services, have similar production processes and use the same methods to provide their services. They also serve the same or similar customers, which include major multi-national, independent and national or state-owned oil companies.

Canada Pressure Pumping segment has one operating segment. Like International and U.S./Mexico Pressure Pumping, it includes cementing and stimulation services (consisting of fracturing, acidizing, sand control, nitrogen, coiled tubing and service tool services). These services are provided to customers in major oil and natural gas producing areas of Canada.

The Oilfield Services segment has five operating segments. These operating segments provide other oilfield services such as production chemicals, casing and tubular services, process and pipeline services, completion tools and completion fluids services in the U.S. and in select markets internationally. The operating segments have been aggregated into one reportable segment as they all provide other oilfield services, serve same or similar customers and some of the operating segments share resources.

The accounting policies of the segments are the same as those described in the summary of significant accounting policies. We evaluate the performance of our segments based on operating income. Intersegment sales and transfers are not material.

Summarized financial information concerning our segments for each of the three years ended September 30, 2006 is shown in the following tables (in thousands). The "Corporate" column includes corporate expenses not allocated to the operating segments. Revenue by geographic location is determined based on the location in which services are rendered or products are sold. For the years ended September 30, 2006, 2005 and 2004, we provided services to several thousand customers, none of which accounted for more than 5% of consolidated revenue.

Business Segments

	U.S./Mexico Pressure Pumping	International Pressure Pumping	Canada Pressure Pumping	Oilfield Services Group	Corporate	Total
2006						
Revenue	$2,353,772	$ 884,670	$481,380	$648,042	$ —	$4,367,864
Operating income (loss)	899,213	138,069	102,094	132,420	(100,060)	1,171,736
Total assets	1,294,946	1,022,265	471,362	707,015	366,700	3,862,288
Capital expenditures	202,423	87,822	106,352	42,499	20,878	459,974
Depreciation	65,569	49,119	24,025	22,730	5,320	166,763
2005						
Revenue	$1,683,202	$ 693,462	$348,448	$517,650	$ 424	$3,243,186
Operating income (loss)	524,893	77,525	58,313	67,626	(91,298)	637,059
Total assets	1,049,019	855,054	351,034	594,950	559,585	3,409,642
Capital expenditures	149,986	49,222	66,135	34,906	23,514	323,763
Depreciation	51,990	43,835	16,892	20,206	3,938	136,861
2004						
Revenue	$1,269,786	$ 597,881	$293,546	$438,788	$ 985	$2,600,986
Operating income (loss)	337,030	44,069	47,340	54,030	(44,084)	438,385
Total assets	901,272	781,717	275,011	549,051	783,646	3,290,697
Capital expenditures	92,080	47,402	15,286	31,704	14,105	200,577
Depreciation	45,699	40,997	15,417	19,492	4,063	125,668

Geographic Information

	Revenue	Long-Lived Assets
2006		
United States	$2,600,864	$1,732,411
Canada	526,609	260,530
Other countries	1,240,391	380,930
Consolidated total	$4,367,864	$2,373,871
2005		
United States	$1,820,191	$1,519,193
Canada	392,380	172,609
Other countries	1,030,615	346,085
Consolidated total	$3,243,186	$2,037,887
2004		
United States	$1,357,139	$1,385,343
Canada	331,521	114,642
Other countries	912,326	342,505
Consolidated total	$2,600,986	$1,842,490

Revenue by Product Line

	2006	2005	2004
Cementing	$1,090,787	$ 822,447	$ 745,929
Stimulation	2,560,063	1,835,560	1,361,273
Other	717,014	585,179	493,784
Total revenue	$4,367,864	$3,243,186	$2,600,986

A reconciliation from the segment information to consolidated income before income taxes for each of the three years ended September 30, 2006 is set forth below (in thousands):

	2006	2005	2004
Total operating profit for reportable segments	$1,171,736	$637,059	$438,385
Interest expense	(14,558)	(10,951)	(16,389)
Interest income	14,916	11,281	6,073
Other (expense) income, net	(11)	15,958	92,668
Income before income taxes	$1,172,083	$653,347	$520,737

9. Employee Benefit Plans

We administer defined contribution plans for employees in the U.S., the U.K and Canada whereby eligible employees may elect to contribute from 2% to 20% of their base salaries to an employee benefit trust. We match employee contributions at the rate of $1.00 per $1.00 up to 6% of the employee's base salary in the U.S., and an equal matching up to 5.5% of the employee's base salary in the U.K. In addition, we contribute between 2% and 6% of each employee's base salary depending on their age or years of service in the U.S., the U.K. and Canada. Our matching contributions vest immediately while our base contributions become fully vested after five years of employment. Contributions to these defined contribution plans were $23.9 million, $16.6 million, and $14.3 million, in fiscal 2006, 2005, and 2004, respectively.

Effective October 1, 2000, we established a non-qualified supplemental executive retirement plan. The unfunded defined benefit plan will provide our executives with supplemental retirement benefits based on the highest consecutive three years compensation out of the final ten years and become vested at age 55. The expense associated with this plan was $2.9 million, $2.1 million, and $3.4 million for the years ended September 30, 2006, 2005, and 2004, respectively. The related accrued benefit obligation was $16.5 million and $14.1 million as of September 30, 2006 and 2005, respectively.

Effective December 7, 2000, we established a non-qualified directors' benefit plan. The unfunded defined benefit plan will provide our non-employee directors with benefits upon termination of their service based on the number of years of service and the last annual retainer fee. The expense associated with this plan was $0.7 million, $0.5 million and $0.1 million for the years ended September 30, 2006, 2005, and 2004, respectively. The related accrued benefit obligation was $2.9 million and $2.3 million as of September 30, 2006 and 2005, respectively.

Defined Benefit Pension Plans

We have defined benefit pension plans covering certain employees in the U.S., the U.K., Norway and Canada. During fiscal 2004, the plans were frozen to new entrants in the U.K. and Canada.

The defined benefit pension plan in the U.S. was frozen effective December 31, 1995, at which time all earned benefits were vested. In September 2006, we entered into an agreement to settle our obligation with respect to the U.S. defined benefit plan. Plan assets of approximately $72 million, plus our contribution of $1.5 million, were used to purchase an insurance contract that will be used to fund the benefits and settle the plan. The proposed settlement requires approval from the Pension Benefit Guaranty Corporation and the Internal Revenue Service to relieve us of primary responsibility for the pension benefit obligation. Once regulatory approval is obtained, which is expected in fiscal 2007, we will expense approximately $23.3 million of prepaid pension cost. The $23.3 million asset represents the difference between the amounts we have funded over time and the amount required to be expensed under SFAS No. 87. By relieving us of our obligation, the expense that would have otherwise been recognized over the remaining plan life will be accelerated to the period in which approval is received. As a result of these actions, we have reclassified the pension asset and recorded the payment for the annuity as current assets.

We use a September 30 measurement date for these plans. All amounts are presented in thousands unless otherwise stated.

Obligations and Funded Status

	U.S.		Non-U.S.	
	2006	2005	2006	2005
Change in benefit obligation				
Benefit obligation, beginning of year	$64,490	$68,451	$149,758	$125,003
Service cost	—	—	5,077	4,823
Interest cost	3,582	3,826	8,481	7,609
Actuarial (gain)/loss	689	(4,163)	15,068	14,635
Benefits paid from plan assets	(3,671)	(3,624)	(2,787)	(4,129)
Contributions by plan participants	—	—	2,085	2,155
Foreign currency exchange rate change	—	—	8,761	(338)
Defined benefit plan obligation, end of year	$65,090	$64,490	$186,443	$149,758
Change in plan assets				
Fair value of plan assets, beginning of year	$69,082	$64,765	$107,217	$ 85,026
Actual return on plan assets	5,320	6,883	9,249	16,248
Contributions by employer	1,465	1,058	7,259	7,757
Contributions by plan participants	—	—	2,085	2,155
Benefits paid from plan assets	(3,671)	(3,624)	(2,787)	(4,129)
Foreign currency exchange rate change	—	—	6,104	160
Fair value of plan assets, end of year	$72,196	$69,082	$129,127	$107,217
Over (under) funded status	$ 7,106	$ 4,592	$ (57,316)	$ (42,541)
Unrecognized net actuarial loss	16,040	15,526	55,346	43,061
Unrecognized prior service cost	—	—	—	23
Unrecognized transitional (gain) loss	—	—	2,280	(140)
Prepaid (accrued) net amount recognized	$23,146	$20,118	$ 310	$ 403

Amounts recognized in the consolidated statement of financial position consist of:

	U.S.		Non-U.S.	
	2006	2005	2006	2005
Prepaid benefit cost	$23,146	$20,118	$ 3,409	$ 3,578
Accrued benefit cost	—	—	(49,996)	(32,688)
Intangible assets	—	—	—	23
Accumulated other comprehensive income	—	—	46,897	29,490
Net amount recognized	$23,146	$20,118	$ 310	$ 403

Accumulated Benefit Obligations (ABO) in Excess of Plan Assets

The ABO is the actuarial present value of the pension benefits at the employees' current compensation levels. This differs from the projected benefit obligation, in that the ABO does not include any assumptions about future compensation levels. The ABO for all the plans was $239.8 million and $197.2 million at September 30, 2006 and 2005, respectively.

	U.S.		Non-U.S.	
	2006	2005	2006	2005
Projected benefit obligation	$65,090	$64,490	$186,443	$149,758
Accumulated benefit obligation	65,090	64,490	174,735	132,719
Plan assets at fair value	72,196	69,082	129,127	107,217

Components of Net Periodic Benefit Cost

	U.S.			Non-U.S.		
	2006	2005	2004	2006	2005	2004
Service cost for benefits earned	$ —	$ —	$ —	$ 5,074	$ 4,823	$ 4,452
Interest on projected benefit obligation	3,582	3,826	3,802	8,456	7,609	6,254
Expected return on plan assets	(5,732)	(5,343)	(4,010)	(8,114)	(6,898)	(5,627)
Recognized actuarial loss	587	587	—	2,170	2,209	1,820
Net amortization	—	—	628	122	74	43
Net pension cost (benefit)	$(1,563)	$ (930)	$ 420	$ 7,708	$ 7,817	$ 6,942

Additional Information

	U.S.		Non-U.S.	
	2006	2005	2006	2005
Increase (decrease) in minimum liability included in other comprehensive income	N/A	$(13,854)	$11,049	$57

Assumptions

Assumptions used to determine benefit obligations at September 30, were as follows:

	U.S.			Non-U.S.		
	2006	2005	2004	2006	2005	2004
Weighted-average discount rate	6.0%	5.7%	5.8%	5.0-5.5%	5.0-5.5%	5.8-6.3%
Weighted-average expected long-term rate of return on assets	8.5%	8.5%	8.5%	6.0-7.3%	6.0-7.6%	6.3-8.2%

Assumptions used to determine net periodic benefit cost for the years ended September 30, were as follows:

	U.S.			Non-U.S.		
	2006	2005	2004	2006	2005	2004
Weighted-average discount rate	5.7%	5.8%	5.8%	5.0-5.5%	5.0-5.5%	5.8-6.3%
Weighted-average expected long-term rate of return on assets	8.5%	8.5%	8.5%	6.0-7.3%	6.0-7.6%	6.3-8.2%
Weighted-average rate of increase in future compensation	N/A	N/A	N/A	3.8-4.5%	3.5-4.5%	3.8-4.5%

The expected long-term rate of return assumptions represent the rate of return on plan assets reflecting the average rate of earnings expected on the funds invested or to be invested to provide for the benefits included in the projected benefit obligation. The assumption has been determined by reflecting expectations regarding future rates of return for the portfolio considering the asset distribution target and related historical rates of return. The redemption yield on government fixed interest bonds as well as corporate bonds were used as proxies for the return on debt securities, weighted by the relative proportion of each within the actual portfolio. The return on equities was based on the historical long-term performance of the equity classes. This rate is reassessed at least on an annual basis.

Plan Assets

Our objective is to diversify the portfolio among several asset classes to reduce volatility while maintaining an asset mix that provides the highest rate of return with an acceptable risk. This is primarily through a mix of equity securities (between 60 – 75%) and fixed income funds (between 25 – 40%) to generate asset returns comparable with the general market.

We have investment committees that meet at least annually to review the portfolio returns and to determine asset-mix targets based on asset/liability studies. Nationally recognized third-party investment consultants assist us in developing an asset allocation strategy to determine our expected rate of return and expected risk for various investment portfolios. The investment committees consider these studies in the formal establishment of the current asset-mix targets based on the projected risk and return levels for each asset class. Investment portfolio as of September 30, 2006 and 2005 was:

	U.S.			Non-U.S.		
	Target	2006	2005	Target	2006	2005
Equity securities	60%	0%	62%	60-75%	62%	69%
Debt securities	40%	0%	34%	25-35%	35%	29%
Other[1]	0%	100%	4%	0-5%	3%	2%

[1] Plan assets of approximately $71 million, plus our contribution of $1.5 million, were used to purchase an insurance contract that will be used to fund the benefits and settle the U.S. plan.

Contributions and Estimated Benefit Payments

The pension plans are generally funded with the amounts necessary to meet the legal or contractual minimum funding requirements, which totaled $7.3 million in fiscal 2006. We infrequently make discretionary contributions. We expect to contribute $8.1 million to the defined benefit plans in fiscal 2007, which represents the legal or contractual minimum funding requirements.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Years ended September 30,	
2007[1]	$ 2,149
2008	2,366
2009	2,737
2010	3,417
2011	3,679
Years 2012-2016	21,742

[1] As disclosed above, an annuity contract was purchased for the U.S. plan and therefore, approximately $72 million will be distributed to plan participants in the form of individual annuity contracts in 2007. As such, the benefit payments related to this plan are not included in the above schedule.

Postretirement Benefit Plans

We sponsor plans that provide certain health care and life insurance benefits for retired employees (primarily U.S.) who meet specified age and service requirements, and their eligible dependents. These plans are unfunded and we retain the right, subject to existing agreements, to modify or eliminate them. Our postretirement medical benefit plan provides credits based on years of service that can be used to purchase coverage under the retiree plan. This plan effectively caps our health care inflation rate at a 4% increase per year. We use a September 30 measurement date for these plans. All amounts are presented in thousands unless otherwise stated.

Obligations and Funded Status

	2006	2005
Change in benefit obligation		
Benefit obligation, beginning of year	$ 49,906	$ 45,801
Service cost	3,467	3,295
Interest cost	2,870	2,634
Actuarial (gain)/loss	(751)	(1,333)
Benefits paid from plan assets	(460)	(491)
Contributions by plan participants	—	—
Defined benefit plan obligation, end of year	$ 55,032	$ 49,906
Change in plan assets		
Fair value of plan assets, beginning of year	$ —	$ —
Contributions by employer	460	491
Benefits paid from plan assets	(460)	(491)
Fair value of plan assets, end of year	$ —	$ —
Funded status	$(55,032)	$(49,906)
Unrecognized net actuarial loss	659	1,411
Unrecognized prior service cost	—	—
Prepaid (accrued) net amount recognized	$(54,373)	$(48,495)

The ABO was $55.0 million and $49.9 million at September 30, 2006 and 2005, respectively.

Amounts recognized in the consolidated statement of financial position consist of:

	2006	2005
Prepaid benefit cost	$ —	$ —
Accrued benefit cost	(54,372)	(48,495)
Intangible assets	—	—
Accumulated other comprehensive income	—	—
Net amount recognized	$(54,372)	$(48,495)

The postretirement benefit obligation at September 30, 2006 and 2005 was determined using a discount rate of 6.0% and 5.75%, respectively, and a health care cost trend rate of 4%, reflecting the cap described above. Increasing the assumed health care cost trend rates by one percentage point would not have a material impact on the accumulated postretirement benefit obligation or the net periodic postretirement benefit cost because these benefits are capped.

Components of Net Periodic Benefit Cost

	2006	2005	2004
Service cost for benefits earned	$3,468	$3,295	$2,915
Interest on projected benefit obligation	2,870	2,634	2,389
Net pension cost (benefit)	$6,338	$5,929	$5,304

The postretirement benefit cost at September 30, 2006, 2005 and 2004 was determined using a discount rate of 5.75%, 5.75% and 5.85%, respectively, and a health care cost trend rate of 4%, reflecting the cap described above.

Contributions and Estimated Benefit Payments

The postretirement plan is generally funded with the amounts necessary to meet benefit costs as they are incurred. We expect to contribute $1.3 million to the post retirement plan in fiscal 2007, which represents the anticipated claims.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Years ended September 30,	
2007	$ 1,326
2008	1,800
2009	2,286
2010	2,844
2011	3,444
Years 2012-2016	26,798

10. Commitments and Contingencies

Litigation

We, through performance of our service operations, are sometimes named as a defendant in litigation, usually relating to claims for bodily injuries or property damage (including claims for well or reservoir damage). We maintain insurance coverage against such claims to the extent deemed prudent by management. Further, through a series of acquisitions, we assumed responsibility for certain claims and proceedings made against the Western Company of North America, Nowsco Well Service Ltd., OSCA and other companies whose stock we acquired in connection with their businesses. Some, but not all, of such claims and proceedings will continue to be covered under insurance policies of our predecessors that were in place at the time of the acquisitions.

Although the outcome of the claims and proceedings against us (including Western, Nowsco and OSCA) cannot be predicted with certainty, management believes that there are no existing claims or proceedings that are likely to have a material adverse effect on our financial position or results of operations for which it has not already provided.

Newfield Litigation

On April 4, 2002, a jury rendered a verdict adverse to OSCA in connection with litigation pending in the United States District Court for the Southern District of Texas (Houston). The lawsuit, filed by Newfield Exploration on September 29, 2000, arose out of a blowout that occurred in 1999 on an offshore well owned by Newfield. The jury determined that OSCA's negligence caused or contributed to the blowout and that it was responsible for 86% of the damages suffered by Newfield. The total damage amount awarded to Newfield was $15.6 million (excluding pre- and post-judgment interest). The Court delayed entry of the final judgment in this case pending the completion of the related insurance coverage litigation filed by OSCA against certain of its insurers and its former insurance broker. The Court elected to conduct the trial of the insurance coverage issues based upon the briefs of the parties. In the interim, the related litigation filed by OSCA against its former insurance brokers for errors and omissions in connection with the policies at issue in this case has been stayed. On February 28, 2003, the Court issued its final judgment in connection with the Newfield claims, based upon the jury's verdict. At the same time, the Court issued rulings adverse to OSCA in connection with its claim for insurance coverage. Motions for New Trial were denied by the Judge and the case was appealed to the U.S. Court of Appeals for the Fifth Circuit, both with regard to the liability case and the insurance coverage issues. The Fifth circuit issued its ruling on April 12, 2006 finding against OSCA on the liability issues, but ruling in OSCA's favor on insurance coverage. Based on the Fifth Circuit's opinion, we believe that over half of the judgment against OSCA is covered by an insurance policy issued by AISLIC (an AIG affiliate). AISLIC filed a Motion for Re-hearing with the Fifth Circuit, which was denied. The case has been remanded to the District Court (as of June 5, 2006) for further consideration of one exclusion contained in the AISLIC policy. Even if the interpretation of this exclusion is resolved in a manner that is adverse to OSCA, a majority of the judgment against OSCA will remain covered by the AISLIC policy. Upon remand, Newfield filed a motion to enforce its judgment against OSCA, which the court denied. Great Lakes Chemical Corporation, (which owned the majority of the outstanding shares of OSCA at the time of the acquisition) agreed to indemnify OSCA for 75% of any uninsured liability in excess of $3 million arising from the Newfield litigation. Taking this indemnity into account and without regard to the outcome of the insurance coverage dispute, our share of the verdict is approximately $5.5 million. We are fully reserved for our share of this liability.

Asbestos Litigation

In August 2004, certain predecessors of the Company, along with numerous other defendants were named in four lawsuits filed in the Circuit Courts of Jones and Smith Counties in Mississippi. These four lawsuits included 118 individual plaintiffs alleging that they suffer various illnesses from exposure to asbestos and seeking damages. The lawsuits assert claims of unseaworthiness, negligence, and strict liability, all based upon the status of the Company's predecessors as Jones Act employers. The plaintiffs were required to complete data sheets specifying the companies they were employed by and the asbestos-containing products to which they were allegedly exposed. Through this process, approximately 25 plaintiffs have identified the Company or its predecessors as their employer. Amended lawsuits were filed by four individuals against the Company and the remainder of the original claims (114) were dismissed. Of these four lawsuits, three failed to name the Company as an employer or manufacturer of asbestos containing products so we were thereby dismissed. Subsequently an individual from one of these lawsuits brought his own action against the Company. As a result, we are currently named as an employer in two of the Mississippi lawsuits. It is possible that as many as 21 other claimants who identified the Company or its predecessors as their employer could file suit against the Company, but they have not done so at this time. Only minimal medical information regarding the alleged asbestos-related disease suffered by the plaintiffs in the two lawsuits has been provided. Accordingly, the Company is unable to estimate its potential exposure to these lawsuits. The Company and its predecessors in the past maintained insurance which may be available to respond to these claims. In addition to the Jones Act cases, the Company has been named in a small number of additional asbestos cases. The allegations in these cases vary, but generally include claims that the Company provided some unspecified product or service which contained or utilized asbestos. Some of the allegations involve claims that the Company is the successor to the Byron Jackson Company. To date, the Company has been successful in obtaining dismissals of such cases without any payment in settlements or judgments, although some remain pending at the present time. The Company intends to defend itself vigorously in all of these cases and, based on the information available to the Company. At this time, the Company does not expect the outcome of these lawsuits, individually or collectively, to have a material adverse effect on its financial position, results of operations or cash flows; however, there can be no assurance as to the ultimate outcome of these lawsuits or additional similar lawsuits, if any, that may be filed.

Gene Ellison et al v FPC Disposal et al

On December 12, 2000, Gene and Marcia Ellison filed a lawsuit in State District Court of Canadian County, Oklahoma against the Company and about 120 defendants, including Western and FPC Disposal, Inc., which owns and operates a commercial facility for the disposal of oil/gas well drilling fluids, cuttings and salt water located one-half mile from property owned by the Ellisons on which they conduct farming and ranching activities in Canadian County, Oklahoma. In their original Complaint, the Ellisons alleged that both the Company and Western sent flow-back water to the well for disposal and that the disposal activities polluted their water and therefore their property. In the original Complaint, the Ellisons sought actual and punitive damages in excess of $10 thousand for property damage, personal annoyance and endangerment of their comfort, health, tranquility and safety.

In April 2002, the Company filed a Motion for Summary Judgment, which was granted by the State District Court. The Plaintiffs appealed the motion for summary judgment. The Oklahoma Appeals Court reversed the Trial Court's decision. The Company ultimately filed a Petition for Writ of Certiorari that was denied by the Oklahoma Supreme Court. The lawsuit was sent back to the trial court and the case has proceeded. In late September 2006, the Plaintiffs quantified their actual damages in excess of $500.0 million, claiming under theories of remediation, unjust enrichment and lost profits. In addition, the Plaintiffs are seeking punitive damages against the Company of up to $51.8 million.

The Company and Western allegedly supplied approximately 1.75% of the loads alleged to have polluted the disposal pit between 1988 and 1995. Loads were diluted by the operator, FPC, in accordance with procedures known to and approved by the Oklahoma Corporation Commission. At this time, the Company does not expect the outcome of this lawsuit to have a material adverse effect on its financial position, results of operations or cash flows; however, there can be no assurance as to the ultimate outcome.

Environmental

Federal, state and local laws and regulations govern our operation of underground fuel storage tanks. Rather than incur additional costs to restore and upgrade tanks as required by regulations, management has opted to remove the existing tanks. We have completed the removal of these tanks and have remedial cleanups in progress related to the tank removals. In addition, we are conducting environmental investigations and remedial actions at current and former Company locations and, along with other companies, is currently named as a potentially responsible party at four waste disposal sites owned by third parties. An accrual of approximately $4.2 million has been established for such environmental matters, which is management's best estimate of our portion of future costs to be incurred. Insurance is also maintained for some environmental liabilities.

Lease and Other Long-Term Commitments

In 1999, we contributed certain pumping service equipment to a limited partnership. We own a 1% interest in the limited partnership. The equipment is used to provide services to our customers for which we pay a service fee over a period of at least six years, but not more than 13 years, at approximately $12 million annually. This is accounted for as an operating lease. We assessed the terms of this agreement and determined it was a variable interest entity as defined in FIN 46, *Consolidation of Variable Interest Entities*. However, we were not deemed to be the primary beneficiary, and therefore, consolidation was not required. The transaction resulted in a gain that is being deferred and amortized over 13 years. The balance of the deferred gain was $16.1 million and $22.1 million as of September 30, 2006 and September 30, 2005, respectively. The agreement permits substitution of equipment within the partnership as long as the implied fair value of the new property transferred in at the date of substitution equals or exceeds the implied fair value, as defined, of the current property in the partnership that is being replaced. As a result of the substitutions, the deferred gain was reduced by $2.8 million in fiscal 2006 and $1.1 million in fiscal 2005. In September 2010, we have the option, but not the obligation, to purchase the pumping service equipment for approximately $32 million. We currently have the intent to exercise this option.

In 1997, we contributed certain pumping service equipment to a limited partnership. We own a 1% interest in the limited partnership. The equipment is used to provide services to our customers for which we pay a service fee over a period of at least eight years, but not more than 13 years, at approximately $10 million annually. This is accounted for as an operating lease. We assessed the terms of this agreement and determined it was a variable interest entity as defined in FIN 46, *Consolidation of Variable Interest Entities*. However, we were not deemed to be the primary beneficiary, and therefore, consolidation was not required. The transaction resulted in a gain that is being deferred and amortized over 12 years. There was no deferred gain at September 30, 2006 and the deferred gain balance at September 30, 2005 was $0.3 million. The agreement permits substitution of equipment within the partnership as long as the implied fair value of the new property transferred in at the date of substitution equals or exceeds the implied fair value, as defined, of the current property in the partnership that is being replaced. As a result of the substitutions, the deferred gain was reduced by $0.3 million in fiscal 2006. In June 2009, we have the option, but not the obligation, to purchase the pumping service equipment for approximately $27 million. We currently have the intent to exercise this option.

The option prices to purchase the equipment under the partnerships depend in part on the fair market value of the equipment held by the partnerships at the time the options are exercised as well as other factors specified in the agreements.

At September 30, 2006, we had long-term operating leases and service fee commitments covering certain facilities and equipment, as well as other long-term commitments, with varying expiration dates. Minimum annual commitments for the years ending September 30, 2007, 2008, 2009, 2010 and 2011 are $62.4 million, $55.5 million, $42.9 million, $12.1 million and $10.1 million, respectively and $14.0 million in the aggregate thereafter.

Contractual Obligations

We routinely issue Parent Company Guarantees ("PCGs") in connection with service contracts entered into by our subsidiaries. The issuance of these PCGs is frequently a condition of the bidding process imposed by our customers for work in countries outside of North America. The PCGs typically provide that we guarantee the performance of the services by our local subsidiary. The term of these PCGs varies with the length of the service contract. To date, the parent company has not been called upon to perform under any of these PCGs.

We arrange for the issuance of a variety of bank guarantees, performance bonds and standby letters of credit. The vast majority of these are issued in connection with contracts we, or our subsidiary, have entered into with customers. The customer has the right to call on the bank guarantee, performance bond or standby letter of credit in the event that we, or our subsidiary, default in the performance of services. These instruments are required as a condition to being awarded the contract, and are typically released upon completion of the contract. The balance of these instruments are predominantly standby letters of credit issued in connection with a variety of our financial obligations, such as in support of fronted insurance programs, claims administration funding, certain employee benefit plans and temporary importation bonds. The following table summarizes our other commercial commitments as of September 30, 2006 (in thousands):

		Amount of commitment expiration per period			
Other Commercial Commitments	**Total Amounts Committed**	**Less than 1 Year**	**1–3 Years**	**4–5 Years**	**Over 5 Years**
Standby Letters of Credit	$ 62,821	$ 52,274	$10,547	$ —	$ —
Guarantees	105,719	51,727	19,860	20,080	14,052
Total Other Commercial Commitments	$168,540	$104,001	$30,407	$20,080	$14,052

The following table summarizes our contractual cash obligations and other commercial commitments as of September 30, 2006 (in thousands):

Contractual Cash Obligations	Total	Less than 1 year	1-3 Years	4-5 Years	After 5 Years
Long term and short term debt	$ 660,274	$160,274	$250,000	$250,000	$ —
Interest on long term debt and capital leases	98,036	29,963	39,323	28,750	—
Capital lease obligations	446	240	206	—	—
Operating leases	132,831	38,382	59,565	25,822	9,062
Equipment financing arrangements[(1)]	122,756	23,803	66,368	32,585	—
Purchase obligations[(2)]	534,307	534,307	—	—	—
Purchase commitments[(3)]	139,015	37,192	48,798	33,873	19,152
Other long-term liabilities[(4)]	81,349	1,025	144	96	80,084
Total contractual cash obligations	$1,769,014	$825,186	$464,404	$371,126	$108,298

(1) As discussed previously, we have the option, but not the obligation, to purchase the pumping service equipment in these two partnerships for approximately $27 million and $32 million in 2009 and 2010, respectively. Currently, we expect to purchase the pumping service equipment and have therefore included the option payment in the table above.

(2) Includes agreements to purchase goods or services that have been approved and that specify all significant terms (pricing, quantity and timing). Our policies do not require a purchase order to be completed for items that are under $200 and are for miscellaneous items, such as office supplies.

(3) We have entered into agreements with certain suppliers to ensure that a certain level of materials are maintained in the U.S. and Canada.

(4) Includes expected cash payments for long-term liabilities reflected in the consolidated balance sheet where the amounts and timing of the payment are known. Amounts include: Asset retirement obligations, known pension funding requirements, post-retirement benefit obligation, environmental accruals and other miscellaneous long-term obligations. Amounts exclude: Deferred gains (see "*Lease and Other Long-Term Commitments*" above), pension obligations in which funding requirements are uncertain and long-term contingent liabilities.

11. Intangible Assets

The changes in the carrying amount of goodwill by reporting unit for the year ended September 30, 2006, are as follows (in thousands):

	U.S./Mexico Pressure Pumping Services	International Pressure Pumping Services	Canada Pressure Pumping Services	Oilfield Services Group	Total
Balance 9/30/04	$274,058	$255,101	$116,223	$240,523	$885,905
Resolution of tax contingency	(2,277)	—	1,584	—	(693)
Balance 9/30/05	$271,781	$255,101	$117,807	$240,523	$885,212
Acquisitions	—	176	—	42,909	43,085
Balance 9/30/06	$271,781	$255,277	$117,807	$283,432	$928,297

During fiscal 2005, goodwill was reduced by $0.7 million in connection with the resolution of certain tax uncertainties relating to prior acquisitions. Under EITF 93-7, *Uncertainties Related to Income Taxes in a Purchase Business Combination*, the resolution of these tax uncertainties is treated as an adjustment of the goodwill originally recorded in the acquisition. As discussed in Note 3, acquisitions of BJSP and Dyna-Coil increased goodwill by $43.1 million in fiscal 2006.

Technology based intangible assets net of accumulated amortization were $19.7 million and $8.2 million at September 30, 2006 and 2005, respectively. As a result of the Dyna-Coil acquisition, other intangibles increased $7.1 million and the remaining increase is primarily a result of the development of specialty tools. Amortization for the three years ended September 30, 2006, 2005 and 2004 was $0.7 million, $0.5 million and $0.3 million, respectively.

12. Supplemental Financial Information

Supplemental financial information for the years ended September 30 is as follows (in thousands):

	2006	2005	2004
Consolidated statement of operations:			
Research and development expense	$ 24,263	$ 21,172	$20,414
Rent expense	74,222	75,811	73,072
Net operating foreign exchange loss (gain)	(1,303)	(740)	608
Consolidated statement of cash flows:			
Income tax paid	336,230	187,195	52,355
Interest paid	8,393	8,078	8,073
Details of acquisitions:			
Fair value of assets acquired	51,042	—	9,254
Liabilities assumed	31,324	—	112
Goodwill[1]	43,087	—	6,195
Cash paid for acquisitions, net of cash acquired	52,172	—	15,337

[1] Includes step acquisition entries for BJSP (see Note 3).

Other (expense) income, net for the years ended September 30 is summarized as follows (in thousands):

	2006	2005	2004
Rental income	$ 620	$ 159	$ 214
Minority interest	(3,970)	(3,725)	(2,286)
Non-operating net foreign exchange gain / (loss)	(1,800)	746	(146)
Gain on insurance recovery	1,099	239	272
Gain (loss) from equity method investments	432	1,546	(6,605)
Refund of indirect taxes	—	85	705
Halliburton award	—	—	86,413
Recovery of misappropriated funds (see below)	2,791	9,020	—
Reversal of excess liabilities in Asia Pacific (see below)	—	9,484	12,206
Other, net	817	(1,596)	1,895
Other (expense) income, net	$ (11)	$15,958	$92,668

In October 2004, the Company received a report from a whistleblower alleging that its Asia Pacific Region Controller had misappropriated Company funds in fiscal 2001. The Company began an internal investigation into the misappropriation and whether other inappropriate actions occurred in the Region. The Region Controller admitted to multiple misappropriations totaling approximately $9.0 million during a 30-month period ended April 2002. The misappropriations of approximately $9.0 million were repaid to the Company and the Region Controller's employment was terminated. The misappropriations were an expense of the Company in the form of theft that were recorded in the Consolidated Statement of Operations in periods prior to April 2002. The $9.0 million repayment represents a gain contingency and was reflected in Other Income in the Consolidated Condensed Statement of Operations for the quarter ended December 31, 2004 in accordance with SFAS 5, *Accounting for Contingencies*.

Prior to filing our report on Form 10-K for fiscal 2004, we conducted a review of the Asia Pacific Region's balance sheet and determined that net excess accrued liabilities had accumulated over a period of years which still existed at September 30, 2004 in the amount of $12.2 million. Based on a comprehensive analysis, we identified a further $9.5 million of excess accrued liabilities in the Asia Pacific Region, which were reversed in the fourth quarter of fiscal 2005. The following adjustments were recorded in accordance with GAAP and our policies:

	2005	2004
Gross reduction of other accrued liabilities	$ 2.8	$10.6
Adjustments of and reclassifications to balance sheet accounts	7.6	(7.8)
Net reduction of excess accruals	10.4	2.8
(Addition) reduction of minority interest liability	(0.9)	9.4
Net increase to income before tax	9.5	12.2
Income tax provision	(2.9)	(.9)
Total increase to net income	$ 6.6	$11.3

The net effect of these adjustments was reported in Other Income in the Consolidated Statement of Operations for the years ended September 30, 2005 and 2004. No such adjustments were identified in fiscal 2006.

The Company is continuing to investigate whether additional funds were misappropriated beyond the $9.0 million originally identified. The Company has identified an additional $1.7 million that it believes was misappropriated by the former Region Controller. The additional $1.7 million of likely misappropriations were expenses of the Company that were recorded in the Consolidated Statement of Operations in periods prior to April 2002. It is possible that additional information could emerge resulting in further adjustments in the Consolidated Statements of Operations, but no material adjustments are known at this time.

In October 2004, the Company also received whistleblower allegations that illegal payments to foreign officials had been made in the Asia Pacific Region. The Audit Committee of the Board of Directors engaged independent counsel to conduct a separate investigation to determine whether any such illegal payments were made. The investigation found information indicating a significant likelihood that payments, made by the Company to an entity in the Asia Pacific Region with which the Company has certain contractual relationships, were then used to make payments to government officials in the Asia Pacific Region. This information included information indicating that certain employees of the Company in the Asia Pacific Region believed that the funds paid to the entity would be used to make payments to government officials. The payments, which may have been illegal, aggregated approximately $2.6 million and were made from fiscal 1999 through 2004.

Thereafter, in December 2005, the Company received a payment of approximately $2.8 million from the entity referenced above. The entity said that the funds represented the $2.6 million of funds described above, plus an interest amount, and that the $2.6 million had been misappropriated for the benefit of certain of that entity's employees and was not used to make payments to government officials. The Audit Committee's investigation was not able to verify this claim. The $2.8 million payment represents a gain contingency and was reflected in Other Income in the Consolidated Condensed Statement of Operations for the quarter ended December 31, 2005 in accordance with SFAS 5, *Accounting for Contingencies*.

The Company and the Audit Committee also investigated a large volume of other payments made by the Company during the period of fiscal 1998 through 2004 in the Asia Pacific Region. With respect to approximately $10 million of these payments, the investigations to date either have not been able to establish the legitimacy of the transactions reflected in the underlying documents or have not been able to resolve questions about the adequacy of the underlying documents to support the accounting entries. These payments may have been proper, but due to circumstances surrounding the payments, the investigations have not been able to determine whether theft, illegal payments or other improprieties may have been involved. The payments have been previously expensed, and therefore the Company believes that no additional expense is required to be recorded for such payments.

The Company has voluntarily disclosed information found in the special Audit Committee investigation, as well as related information from the Company's theft investigation, to the U.S. Department of Justice ("DOJ") and U.S. Securities and Exchange Commission ("SEC") and is engaged in ongoing discussions with these authorities as they review the matter. The Company cannot predict whether further investigative efforts may be required or initiated by the authorities.

In connection with discussions regarding possible illegal payments in the Asia Pacific Region, U.S. government officials raised a question whether the Company had made illegal payments to a contractor or intermediary to obtain business in a country in Central Asia. The Audit Committee has investigated this question. The Company has voluntarily disclosed information found in the investigation to the DOJ and SEC and is engaged in ongoing discussions with these authorities as they review the matter.

The DOJ, SEC and other authorities have a broad range of civil and criminal sanctions under the U.S. Foreign Corrupt Practices Act and other laws, which they may seek to impose against corporations and individuals in appropriate circumstances including, but not limited to, injunctive relief, disgorgement, fines, penalties and modifications to business practices and compliance programs. Such agencies and authorities have entered into agreements with, and obtained a range of sanctions against, several public corporations and individuals arising from allegations of improper payments and deficiencies in books and records and internal controls, whereby civil and criminal penalties were imposed, including in some cases multi-million dollar fines and other sanctions. We are in discussions with the DOJ and SEC regarding certain of the matters described above. It is not possible to accurately predict at this time when any of these matters will be resolved. Based on current information, we cannot predict the outcome of such investigations, whether we will reach resolution through such discussions or what, if any, actions may be taken by the DOJ, SEC or other authorities or the effect the foregoing may have on our consolidated financial statements.

The misappropriations and related accounting adjustments in the Asia Pacific Region were possible because of certain internal control operating deficiencies. During fiscal 2002, the Company implemented policy changes worldwide for disbursements. Significant personnel changes were also made in the Asia Pacific Region. The Company has assigned a new Region Manager and a new Region Controller, an Assistant Controller and replaced several accountants in the Asia Pacific region. The Company also took further disciplinary action against personnel in the Region. In addition, we have put in place an Internal Control and Process Improvement function, led by an internal control manager at the corporate office and supported by managers at each of our five regional bases worldwide to document, enhance, and test our control processes.

Accumulated other comprehensive income (loss) consists of the following (in thousands):

	Minimum Pension Liability Adjustment	Cumulative Translation Adjustment	Total
Balance, September 30, 2003	$(31,190)	$21,543	$(9,647)
Changes	(1,729)	10,468	8,739
Balance, September 30, 2004	$(32,919)	$32,011	$ (908)
Changes	13,797	11,482	25,279
Balance, September 30, 2005	$(19,122)	$43,493	$24,371
Changes	(11,049)	9,511	(1,538)
Balance, September 30, 2006	$(30,171)	$53,004	$22,833

The tax effects allocated to each component of changes in other comprehensive income is summarized as follows (in thousands):

	Before-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
Year Ended September 30, 2004:			
Foreign currency translation adjustment	$ 10,468	$ —	$ 10,468
Minimum pension liability adjustment	(2,363)	634	(1,729)
Change in other comprehensive income	$ 8,105	$ 634	$ 8,739
Year Ended September 30, 2005:			
Foreign currency translation adjustment	$ 11,482	$ —	$ 11,482
Minimum pension liability adjustment	21,783	(7,986)	13,797
Change in other comprehensive income	$ 33,265	$(7,986)	$ 25,279
Year Ended September 30, 2006:			
Foreign currency translation adjustment	$ 9,511	$ —	$ 9,511
Minimum pension liability adjustment	(15,784)	4,735	(11,049)
Change in other comprehensive income	$ (6,273)	$ 4,735	$ (1,538)

13. Employee Stock Plans

On October 1, 2005 we adopted SFAS 123(R), using the modified prospective method. SFAS 123(R) is a revision of SFAS 123, *Accounting for Stock-Based Compensation*, and supersedes APB No. 25, *Accounting for Stock Issued to Employees*. Under SFAS 123(R), the cost of employee services received in exchange for stock is measured based on the grant-date fair value (with limited exceptions). That cost is to be recognized over the period during which an employee is required to provide service in exchange for the award (usually the vesting period). The fair value is to be estimated using an option-pricing model. Excess tax benefits, as defined in SFAS 123(R), are recognized as an addition to paid-in capital.

Under the modified prospective method, we began recognizing expense on October 1, 2005 on any unvested awards granted prior to the adoption date of October 1, 2005 expected to vest over the remaining vesting period of the awards. New awards granted after the adoption date will be expensed ratably over the vesting period of the award. As stock based compensation expense is recognized based on awards ultimately expected to vest, we have reduced the expense for estimated forfeitures based on historical forfeiture rates. SFAS 123(R) requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods to reflect actual forfeitures.

On November 10, 2005, the FASB issued FASB Staff Position No. FAS 123(R)-3, "*Transition Election Related to Accounting for Tax Effects of Share-Based Payment Awards*" ("FSP 123(R)-3"). FSP 123(R)-3 provides an alternative method of calculating excess tax benefits (the "APIC pool") from the method defined in SFAS123(R). A one-time election to adopt the transition method in FSP 123(R)-3 is available to those entities adopting SFAS 123(R). We have calculated our APIC pool using the method outlined in SFAS 123(R). The impact of adoption did not materially affect our financial position or results of operations.

We currently have three incentive plans and an Employee Stock Purchase Plan that are affected by SFAS 123(R). Our 1997 Incentive Plan, 2000 Incentive Plan and 2003 Incentive Plan (the "Plans") provide for the granting of stock options to officers, key employees and non-employee directors at an exercise price equal to the fair market value of the stock at the date of the grant and the 2003 Plan provides for director stock awards at no exercise price. The Plans also provide for the granting of performance awards to our officers. An aggregate of 32.0 million shares of Common Stock has been authorized for grants, of which 11.7 million shares were available for future grants at September 30, 2006. The 1999 Employee Stock Purchase Plan (the "Purchase Plan") allows all employees to purchase shares of our Common Stock at 85% of market value on the first or last business day, whichever is lower, of the twelve-month plan period beginning each October 1. Purchases are limited to 10% of an employee's regular salary, or $21,250, whichever is less. An aggregate of 12.0 million shares of Common Stock has been authorized for grants, of which 6.5 million shares were available for future grants at September 30, 2006.

Prior to October 1, 2005 we adopted the disclosure-only provisions of SFAS 123 and accounted for certain of our stock-based compensation using the intrinsic value method prescribed in APB 25. Under APB 25, no compensation expense was recognized for stock options or the stock purchase plan. Compensation expense was recognized for the stock incentive awards and director stock awards.

Under SFAS 123(R), our *unearned compensation* balance at September 30, 2005 was reclassified to capital in excess of par on October 1, 2005. The following table summarizes stock based compensation expense recognized under SFAS 123(R) for fiscal 2006 and for fiscal 2005 and 2004 under APB 25, which was allocated as follows (in thousands):

	2006	2005	2004
Cost of sales and services	$ 3,786	$ 2,089	$ 968
Research and engineering	1,163	860	387
Marketing	2,374	1,720	852
General and administrative	11,013	8,491	3,594
Stock based compensation expense	18,336	13,160	5,801
Tax benefit	(3,631)	(4,803)	(2,029)
Stock based compensation expense, net of tax	$14,705	$ 8,357	$ 3,772

The following table illustrates the effect on net income and earnings per share in fiscal 2006 compared with the pro forma effect on net income and earnings per share in fiscal 2005 and 2004 if we had applied the fair value recognition provisions of SFAS 123 to our stock options and shares reserved under the stock purchase plan (in thousands, except per share amounts):

	Actual 2006	Pro Forma 2005	Pro Forma 2004
Net income, as reported	$804,610	$453,042	$361,041
Add: total stock-based employee compensation expense included in reported net income, net of tax	14,705	8,357	3,772
Less: total stock-based employee compensation expense determined under SFAS 123(R) and SFAS 123, respectively, for all awards, net of tax	(14,705)	(17,258)	(17,714)
Net income	$804,610	$444,141	$347,099
Earnings per share:			
Basic, as reported	$ 2.55	$ 1.40	$ 1.13
Basic, pro forma	$ 2.55	$ 1.37	$ 1.08
Diluted, as reported	$ 2.52	$ 1.38	$ 1.10
Diluted, pro forma	$ 2.52	$ 1.35	$ 1.06

Stock Options: The Plans provide for the granting of stock options to officers, key employees and non-employee directors at an exercise price equal to the fair market value of the stock at the date of the grant. Options outstanding generally vest over three or four-year periods and are exercisable for periods ranging from seven to ten years.

Expected life was determined based on exercise history for the last ten years. On October 1, 2005, we began segregating the grants of options to officers and non-officers for fair value determination under SFAS 123(R) due to differences in exercise patterns. Prior to the adoption of SFAS 123(R), we did not segregate grants into these groups. Beginning October 1, 2005, we calculated estimated volatility using historical daily price intervals to generate expected future volatility based on the appropriate expected lives of the options. Prior to October 1, 2005, we calculated volatility using historical daily, weekly and monthly price intervals to generate a reasonable range of expected future volatility and used a factor at the low end of the range in accordance with SFAS 123. The risk-free interest rate is based on observed U.S. Treasury rates appropriate for the expected lives of the options. The dividend yield is based on our history of dividend payouts.

Compensation expense for grants determined under SFAS 123(R) for the fiscal years ended September 30 was calculated using the Black-Scholes option pricing model with the following assumptions:

Officer grants	2006 Actual	2005 Pro forma	2004 Pro forma
Expected life (years)	5.0	4.7	5.0
Interest rate	4.4%	3.6%	3.7%
Volatility	42.8%	30.4%	36.8%
Dividend yield	0.6%	0.7%	—
Weighted-average fair value per share at grant date	$14.68	$6.99	$6.07
Non-officer grants			
Expected life (years)	3.0	4.7	5.0
Interest rate	4.4%	3.6%	3.7%
Volatility	31.9%	30.4%	36.8%
Dividend yield	0.6%	0.7%	—
Weighted-average fair value per share at grant date	$ 9.19	$6.99	$6.07

A summary of stock option activity and related information is presented below (in thousands, except per share prices) as of September 30, 2006:

		Weighted-Average		
	Shares	Exercise Price	Remaining Contractual Term	Intrinsic Value
Outstanding at beginning of year	8,615	$14.68		
Granted	1,708	35.31		
Exercised	(911)	14.88		
Forfeited	(307)	26.83		
Outstanding at end of year	9,105	18.12	3.5	$165,012
Options exercisable at year-end	5,824	12.76	2.5	74,344
Weighted-average grant date fair value of options granted during the year		$11.70		

The weighted-average grant date fair value of options granted during fiscal 2006, 2005, 2004 was $11.70, $6.99 and $6.07, respectively. The total intrinsic value of options exercised during the years ended September 30, 2006, 2005 and 2004 was $21.1 million, $48.2 million and $78.3 million, respectively.

A summary of the status of unvested shares as of September 30, 2006, and changes during fiscal 2006, is presented below (in thousands, except per share prices):

	Shares	Weighted-Average Grant-Date per Share Fair Value
Unvested at October 1, 2005	3,336	$ 6.62
Granted	1,708	11.70
Vested	(1,457)	6.56
Forfeited	(306)	9.24
Unvested at September 30, 2006	3,281	$ 9.04

As of September 30, 2006, there was $17.9 million of total unrecognized compensation cost related to unvested stock options. That cost is expected to be recognized over a weighted-average period of 3.0 years. The total fair value of shares vested during the years ended September 30, 2006, 2005 and 2004 was $9.6 million, $17.0 million and $18.0 million, respectively.

Director Stock Awards: In addition to stock options, non-employee directors may be granted an award of common stock of the Company with no exercise price ("restricted stock"). Restricted stock awards generally vest over a three year period. Compensation expense determined under SFAS 123(R) was calculated using the Black-Scholes option pricing model and the same assumptions as those used to calculate stock based compensation expense for non officer stock option grants. Prior to adopting SFAS 123(R), compensation expense for restricted stock awards was calculated in the same manner. Expense for director stock awards was $1.3 million, $0.6 million and $0.2 million in fiscal 2006, 2005 and 2004, respectively.

Stock Incentive Awards: For awards made under the 1997 Stock Incentive Plan and 2000 Stock Incentive Plan, we have reserved 681,603 shares of Common Stock for issuance for Performance Units ("Units") that have been awarded, representing the maximum number of shares the officers could receive under outstanding awards. Each Unit represents the right to receive from the Company at the end of a stipulated period one unrestricted share of Common Stock, contingent upon achievement of certain financial performance goals over the stipulated period. Under SFAS 123(R) compensation expense is recorded for the entire grant amount and will not be adjusted regardless of achievement level attained. As a result of personnel leaving prior to the end of the performance period, only $3.6 million was expensed in fiscal 2006, exclusive of the cash award component discussed below. Prior to the adoption of SFAS 123(R), the aggregate fair market value of the underlying shares granted under this plan was considered unearned compensation at the time of grant and was adjusted quarterly based on the then current market price for our common stock. Compensation expense was determined based on management's current estimate of the likelihood of meeting the specific financial goals and expensed ratably over the stipulated period.

In addition to the award of Units, each officer is also awarded cash equal to his or her tax liability on the Units they receive, if any, at the end of the performance period. We recognize compensation expense for the cash award ratably over the performance period and the cash liability is marked to market quarterly according to SFAS 123(R), with the adjustment recorded to compensation expense. At September 30, 2006, we have accrued $3.6 million for the cash award liability for all outstanding grants. However, the actual performance results at the end of a performance period could result in a decrease or increase to the actual cash payments, resulting in an increase or decrease to compensation expense at the end of the performance period.

The performance criteria was not met for the fiscal 2004 grant. In accordance with SFAS 123(R), no compensation expense was reversed for the fair value of this award, however, $4.2 million was reversed for the cash award component.

Under SFAS 123(R), we are recognizing compensation expense for Units granted based on the fair value at the date of the grant using a lattice model (Monte Carlo simulation). The fair values for each grant outstanding as of September 30, 2006 and assumptions used to determine the fair value are listed below:

Fiscal Year	Granted	Forfeited	Outstanding	Volatility	Dividend Yield	Weighted Average Fair value per share
2006	206,779	21,773	185,006	45.54%	0.31%	$30.52
2005	282,912	31,252	251,660	52.05%	0.60%	$25.83
2004	405,166	45,240	359,926	53.21%	—	$15.89

As of September 30, 2006, there was $5.9 million of total unrecognized compensation cost related to these Units. That cost is expected to be recognized over a weighted-average period of 3.0 years. We did not have any Units vest during the years ended September 30, 2006, 2005 and 2004.

Stock Purchase Plan: The Purchase Plan allows all employees to purchase shares of our common stock at 85% of market value on the first or last business day, whichever is lower, of the twelve-month plan period beginning each October. Purchases are limited to 10% of an employee's regular salary. We issued a total of 488,542 shares in fiscal 2006 under the purchase plan, and have reserved 774,911 shares for fiscal 2007. Compensation expense determined under SFAS 123(R) for the year ended September 30, 2006 was calculated using the Black-Scholes option pricing model with the following assumptions:

	2006 Actual	2005 Pro forma	2004 Pro forma
Expected life (years)	1.0	1.0	1.0
Interest rate	4.1%	4.1%	2.2%
Volatility	29.6%	16.4%	15.8%
Dividend yield	0.6%	0.6%	—
Weighted-average fair value per share at grant date	$9.35	$5.49	$6.94

We calculated estimated volatility using historical daily prices based on the appropriate expected life of the stock purchase plan. The risk-free interest rate is based on observed U.S. Treasury rates appropriate for the expected life of the stock purchase plan. The dividend yield is based on our history of dividend payouts.

14. Stockholders' Equity

Common Stock: On January 31, 2006, our stockholders approved a charter amendment increasing the authorized number of shares of common stock from 380,000,000 shares to 910,000,000 shares.

Dividends: Our Board of Directors approved a 2 for 1 stock split to be effected in the form of a stock dividend payable on September 1, 2005 to stockholders of record as of August 18, 2005. Common shares and earnings per share amounts have been restated for all prior periods presented to reflect the increased number of common shares outstanding. From its initial public offering in 1990 until 2004, we did not pay any cash dividends to our stockholders. On July 22, 2004, we announced the initiation of a regular quarterly cash dividend. During fiscal 2005, we paid cash dividends in the amount of $.04 per common share on a quarterly basis and $51.9 million in the aggregate annual amount. On July 28, 2005 our Board of Directors approved a 25% increase in the quarterly cash dividend and declared a cash dividend of $.05 per common share. During fiscal 2006, we paid dividends totaling $64.3 million. We anticipate paying cash dividends in the amount of $.05 per common share on a quarterly basis in fiscal 2007. However, dividends are subject to approval of our Board of Directors each quarter, and the Board has the ability to change the dividend policy at any time.

Stockholder Rights Plan: We have a Stockholder Rights Plan (the "Rights Plan") designed to deter coercive takeover tactics and to prevent an acquirer from gaining control of the Company without offering a fair price to all of our stockholders. The Rights Plan was amended September 26, 2002, to extend the expiration date of the Rights to September 26, 2012 and increase the purchase price of the Rights. Under this plan, as amended, each outstanding share of common stock includes one-eighth of a preferred share purchase right ("Right") that becomes exercisable under certain circumstances, including when beneficial ownership of common stock by any person, or group, equals or exceeds 15% of the Company's outstanding common stock. Each Right entitles the registered holder to purchase from the Company one one-thousandth of a share of Series A Junior Participating Preferred Stock at a price of $520, subject to adjustment under certain circumstances. As a result of stock splits effected in the form of stock dividends in 1998, 2001, and 2005, one Right is associated with eight outstanding shares of common stock. The purchase price for the one-eighth of a Right associated with one share of common stock is effectively $65. Upon the occurrence of certain events specified in the Rights Plan, each holder of a Right (other than an "Acquiring Person," as defined under the Rights Plan) will have the right, upon exercise of such Right, to receive that number of shares of common stock of the Company (or the surviving corporation) that, at the time of such transaction, would have a market price of two times the purchase price of the Right. We have not issued any shares of Series A Junior Participating Preferred Stock.

Treasury Stock: On December 19, 1997, our Board of Directors authorized a stock repurchase program of up to $150 million. Through a series of increases, the stock repurchase program was now authorized to repurchase up to $2.2 billion. Repurchases are made at the discretion of management and the program will remain in effect until terminated by our Board of Directors. We purchased 48,366,000 shares at a cost of $499.0 million through fiscal 2004. During fiscal 2005, we purchased a total of 3,982,000 shares at a cost of $98.4 million. During fiscal 2006, we purchased a total of 31,725,882 shares at a cost of $1,133.3 million. As of September 30, 2006, remaining authority to repurchase Common Stock is $469.3 million. Treasury shares have been utilized for our various stock plans as described in Note 13. A total of 1,509,000 treasury shares were used at a cost of $21.2 million in fiscal 2006, 3,655,000 treasury shares were used at a cost of $45.2 million in fiscal 2005, and 7,126,000 treasury shares were used at a cost of $60.1 million in fiscal 2004.

Subsequent to September 30, 2006, we have purchased 668,889 shares for $20.0 million through November 30, 2006 under our stock repurchase program as discussed in Note 14 of the Notes to the Consolidated Financial Statements. We have authority remaining to purchase up to an additional $449.3 million in stock as of November 30, 2006.

15. Quarterly Financial Data (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Fiscal Year Total
	(in thousands, except per share amounts)				
Fiscal Year 2006:					
Revenue	$956,161	$1,078,818	$1,116,906	$1,215,979	$4,367,864
Gross profit[1]	291,744	350,886	365,524	400,086	1,408,240
Net income	159,657	203,484	212,880	228,589	804,610
Earnings per share:					
Basic	.49	.63	.67	.77	2.55
Diluted	.48	.62	.67	.76	2.52
Fiscal Year 2005:					
Revenue	$737,782	$ 795,863	$ 817,261	$ 892,280	$3,243,186
Gross profit[1]	175,234	209,187	216,065	254,305	854,791
Net income	95,033	109,554	114,193	134,262	453,042
Earnings per share:					
Basic	.29	.34	.35	.42	1.40
Diluted	.29	.33	.35	.41	1.38

(1) Represents revenue less cost of sales and services and research and engineering expenses.

PART IV

ITEM 15. Exhibits and Financial Statement Schedules

(a) List of documents filed as part of this report or incorporated herein by reference:

(1) Financial Statements:

The following financial statements of the Registrant as set forth under Part II, Item 8 of this report on Form 10-K on the pages indicated.

	Page in this Form 10-K
Report of Independent Registered Public Accounting Firm	44
Consolidated Statement of Operations for the years ended September 30, 2006, 2005 and 2004	46
Consolidated Statement of Financial Position as of September 30, 2006 and 2005	47
Consolidated Statement of Stockholders' Equity for the years ended September 30, 2006, 2005 and 2004	49
Consolidated Statement of Cash Flows for the years ended September 30, 2006, 2005 and 2004	50
Notes to Consolidated Financial Statements	51

(2) Financial Statement Schedules:

Schedule Number	Description of Schedule	Page Number
II	Valuation and Qualifying Accounts	95

All other financial statement schedules are omitted because of the absence of conditions under which they are required or because all material information required to be reported is included in the consolidated financial statements and notes thereto.

(3) Exhibits:

Exhibit Number	Description of Exhibit
2.1	Agreement and Plan of Merger dated as of November 17, 1994 ("Merger Agreement"), among BJ Services Company, WCNA Acquisition Corp. and The Western Company of North America (filed as Exhibit 2.1 to the Company's Annual Report on Form 10-K for the year ended September 30, 1995 (file no. 1-10570), and incorporated herein by reference).
2.2	First Amendment to Agreement and Plan of Merger dated March 7, 1995, among BJ Services Company, WCNA Acquisition Corp. and The Western Company of North America (filed as Exhibit 2.2 to the Company's Annual Report on Form 10-K for the year ended September 30, 1995 (file no. 1-10570), and incorporated herein by reference).
2.3	Agreement and Plan of Merger dated as of February 20, 2002, among BJ Services Company, BJTX, Co., and OSCA, Inc. (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K dated May 31, 2002 and incorporated herein by reference).
3.1	Certificate of Incorporation, as amended as of October 22, 1996 (filed as Exhibit 3.1 to the Company's Annual Report on Form 10-K for the year ended September 30, 1999 (file no. 1-10570) and incorporated herein by reference).
3.2	Certificate of Amendment to Certificate of Incorporation, dated January 22, 1998 (filed as Exhibit 3.2 to the Company's Annual Report on Form 10-K for the year ended September 30, 1999 (file no. 1-10570) and incorporated herein by reference).

Exhibit Number	Description of Exhibit
3.3	Certificate of Amendment to Certificate of Incorporation, dated May 10, 2001 (filed as Exhibit 3.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2001 and incorporated herein by reference).
3.4	Certificate of Amendment to Certificate of Incorporation, dated January 31, 2006 (filed as Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended December 31, 2005 and incorporated herein by reference).
3.5	Certificate of Designation of Series A Junior Participating Preferred Stock, as amended, dated September 26, 1996 (filed as Exhibit 3.2 to the Company's Annual Report on Form 10-K for the year ended September 30, 1996 (file no. 1-10570) and incorporated herein by reference).
3.6	Amended and Restated Bylaws, as of December 4, 2003 (filed as Exhibit 3.6 to the Company's Annual Report of Form 10-K for the year ended September 30, 2003 and incorporated herein by reference).
4.1	Specimen form of certificate for the Common Stock (filed as Exhibit 4.1 to the Company's Registration Statement on Form S-1 (Reg. No. 33-35187) and incorporated herein by reference).
4.2	Amended and Restated Rights Agreement, dated September 26, 1996, between the Company and First Chicago Trust Company of New York, as Rights Agent (filed as Exhibit 4.1 to the Company's Form 8-K dated October 21, 1996 (file no. 1-10570) and incorporated herein by reference).
4.3	First Amendment to Amended and Restated Rights Agreement and Appointment of Rights Agent, dated March 31, 1997, among the Company, First Chicago Trust Company of New York and The Bank of New York, as successor Rights Agent (filed as Exhibit 4.3 to the Company's Annual Report on Form 10-K for the year ended September 30, 1997 (file no. 1-10570) and incorporated herein by reference).
4.4	Second Amendment to Amended and Restated Rights Agreement dated as of September 26, 2002, between the Company and The Bank of New York, as Rights Agent (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K dated September 26, 2002 and incorporated herein by reference).
4.5	Indenture among the Company, BJ Services Company, U.S.A., BJ Services Company Middle East, BJ Service International, Inc. and Bank of Montreal Trust Company, Trustee, dated as of February 1, 1996, which includes the form of 7% Notes due 2006 and Exhibits thereto (filed as Exhibit 4.1 to the Company's Registration Statement on Form S-4 (Reg. No. 333-02287) and incorporated herein by reference).
4.6	First Supplemental Indenture, dated as of July 24, 2001, among the Company, BJ Services Company, U.S.A., BJ Services Company Middle East, BJ Service International, Inc. and The Bank of New York, as successor Trustee (filed as Exhibit 4.5 to the Company's Form 8-A/A, filed on November 14, 2001, with respect to the Company's preferred share purchase rights and incorporated herein by reference).
4.7	Amended and Restated Indenture effective as of April 24, 2002, between the Company and The Bank of New York, as Trustee, with respect to the Convertible Senior Notes due 2022 (filed as Exhibit 4.4 to the Company's Registration Statement on Form S-3/A (Reg. No. 333-96981) and incorporated herein by reference).
4.8	Indenture, dated June 8, 2006, between BJ Services Company, as issuer, and Wells Fargo Bank, N.A., as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K filed on June 12, 2006 and incorporated herein by reference).
4.9	First Supplemental Indenture, dated June 8, 2006, between BJ Services Company, as issuer, and Wells Fargo Bank, N.A., as trustee, with respect to the 5.75% Senior Notes due 2011 (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K filed on June 12, 2006 and incorporated herein by reference).

Exhibit Number	Description of Exhibit
4.10	Second Supplemental Indenture, dated June 8, 2006, between BJ Services Company, as issuer, and Wells Fargo Bank, N.A., as trustee, with respect to the Floating Rate Senior Notes due 2008 (filed as Exhibit 4.3 to the Company's Current Report on Form 8-K filed on June 12, 2006 and incorporated herein by reference).
4.11	Form of Senior Note due 2011(filed as Exhibit 4.4 to the Company's Current Report on Form 8-K filed on June 12, 2006 and incorporated herein by reference).
4.12	Form of Floating Rate Senior Note due 2008 (filed as Exhibit 4.5 to the Company's Current Report on Form 8-K filed on June 12, 2006 and incorporated herein by reference).
10.1	Relationship Agreement dated as of July 20, 1990, between the Company and Baker Hughes Incorporated (filed as Exhibit 10.1 to the Company's Registration Statement on Form S-1 (Reg. No. 33-35187) and incorporated herein by reference).
10.2	Tax Allocation Agreement dated as of July 20, 1990, between the Company and Baker Hughes Incorporated (included as Exhibit A to Exhibit 10.1) (filed as Exhibit 10.2 to the Company's Registration Statement on Form S-1 (Reg. No. 33-35187) and incorporated herein by reference).
†10.3	1990 Stock Incentive Plan, as amended and restated (filed as Exhibit 10.1 to the Company's Registration Statement on Form S-8 (Reg. No. 33-62098) and incorporated herein by reference).
†10.4	Amendment effective December 12, 1996, to 1990 Stock Incentive Plan, as amended and restated (filed as Exhibit 10.4 to the Company's Annual Report on Form 10-K for the year ended September 30, 1996 (file no. 1-10570), and incorporated herein by reference).
†10.5	Amendment effective July 22, 1999 to 1990 Stock Incentive Plan (filed as Exhibit 10.24 to the Company's Annual Report on Form 10-K for the year ended September 30, 1999 (file no. 1-10570), and incorporated herein by reference).
†10.6	Amendment effective January 27, 2000 to 1990 Stock Incentive Plan (filed as Appendix A to the Company's Proxy Statement dated December 20, 1999 (file no. 1-10570) and incorporated herein by reference).
†10.7	BJ Services Company 1995 Incentive Plan (filed as Exhibit 4.5 to the Company's Registration Statement on Form S-8 (Reg. No. 33-58637) and incorporated herein by reference).
†10.8	Amendments effective January 25, 1996, and December 12, 1996, to BJ Services Company 1995 Incentive Plan (filed as Exhibit 10.9 to the Company's Annual Report on Form 10-K for the year ended September 30, 1996 (file no. 1-10570), and incorporated herein by reference).
†10.9	Amendment effective July 22, 1999 to BJ Services Company 1995 Incentive Plan (filed as Exhibit 10.25 to the Company's Annual Report on Form 10-K for the year ended September 30, 1999 (file no. 1-10570), and incorporated herein by reference).
†10.10	Amendment effective January 27, 2000 to BJ Services Company 1995 Incentive Plan (filed as Appendix B to the Company's Proxy Statement dated December 20, 1999 (file no. 1-10570) and incorporated herein by reference).
†10.11	Amendment effective May 10, 2001 to BJ Services Company 1995 Incentive Plan (filed as Appendix B to the Company's Proxy Statement dated April 10, 2001 and incorporated herein by reference).
†10.12	Eighth Amendment effective October 15, 2001 to BJ Services Company 1995 Incentive Plan (filed as Exhibit 10.12 to the Company's Annual Report on Form 10-K for the year ended September 30, 2001 and incorporated herein by reference).
†10.13	1997 Incentive Plan (filed as Appendix B to the Company's Proxy Statement dated December 22, 1997 (file no. 1-10570) and incorporated herein by reference).
†10.14	Amendment effective July 22, 1999 to 1997 Incentive Plan (filed as Exhibit 10.26 to the Company's Annual Report on Form 10-K for the year ended September 30, 1999 (file no. 1-10570), and incorporated herein by reference).

Exhibit Number	Description of Exhibit
†10.15	Amendment effective January 27, 2000 to 1997 Incentive Plan (filed as Appendix C to the Company's Proxy Statement dated December 20, 1999 (file no. 1-10570) and incorporated herein by reference).
†10.16	Amendment effective May 10, 2001 to 1997 Incentive Plan (filed as Appendix C to the Company's Proxy Statement dated April 10, 2001 and incorporated herein by reference).
†10.17	Fifth Amendment effective October 15, 2001 to 1997 Incentive Plan (filed as Exhibit 10.17 to the Company's Annual Report on Form 10-K for the year ended September 30, 2001 and incorporated herein by reference).
†10.18	1999 Employee Stock Purchase Plan (filed as Appendix A to the Company's Proxy Statement dated December 21, 1998 (file no. 1-10570) and incorporated herein by reference).
†10.19	Amendment effective September 23, 1999 to BJ Services Company 1999 Employee Stock Purchase Plan (filed as Exhibit 10.19 to the Company's Annual Report on Form 10-K for the year ended September 30, 2001 and incorporated herein by reference).
†10.20	Third Amendment effective September 1, 2001 to BJ Services Company 1999 Employee Stock Purchase Plan (filed as Exhibit 10.20 to the Company's Annual Report on Form 10-K for the year ended September 30, 2003 and incorporated herein by reference).
†10.21	BJ Services Company 2000 Incentive Plan (filed as Appendix B to the Company's Proxy Statement dated December 20, 2000 and incorporated herein by reference).
†10.22	First Amendment effective March 22, 2001 to BJ Services Company 2000 Incentive Plan (filed as Exhibit 10.2 to the Company's Registration Statement on Form S-8 (Reg. No. 333-73348) and incorporated herein by reference).
†10.23	Second Amendment effective May 10, 2001 to BJ Services Company 2000 Incentive Plan (filed as Appendix D to the Company's Proxy Statement dated April 10, 2001 and incorporated herein by reference).
†10.24	Third Amendment effective October 15, 2001 to BJ Services Company 2000 Incentive Plan (filed as Exhibit 10.24 to the Company's Annual Report on Form 10-K for the year ended September 30, 2001 and incorporated herein by reference).
†10.25	BJ Services Supplemental Executive Retirement Plan effective October 1, 2000 (filed as Exhibit 10.15 to the Company's Annual Report on Form 10-K for the year ended September 30, 2000 and incorporated herein by reference).
†10.26	Key Employee Security Option Plan (filed as Exhibit 10.14 to the Company's Annual Report on Form 10-K for the year ended September 30, 1997 (file no. 1-10570) and incorporated herein by reference).
†10.27	Directors' Benefit Plan, effective December 7, 2000 (filed as Exhibit 10.27 to the Company's Annual Report on Form 10-K for the year ended September 30, 2001 and incorporated herein by reference).
†10.28	BJ Services Deferred Compensation Plan, as amended and restated effective October 1, 2000 (filed as Exhibit 10.29 to the Company's Form 10-Q for the quarter ended March 31, 2001 and incorporated herein by reference).
†10.29	Form of Amended and Restated Executive Severance Agreement between BJ Services Company and certain executive officers (filed as Exhibit 10.28 to the Company's Form 10-Q for the quarter ended March 31, 2000 and incorporated herein by reference).
10.30	Trust Indenture and Security Agreement dated as of August 7, 1997 among First Security Bank, National Association, BJ Services Equipment, L.P. and State Street Bank and Trust Company, as Indenture Trustee (filed as Exhibit 10.15 to the Company's Annual Report on Form 10-K for the year ended September 30, 1997 (file no. 1-10570) and incorporated herein by reference).

Exhibit Number	Description of Exhibit
10.31	Indenture Supplement No. 1 dated as of August 8, 1997 between First Security Bank, as Nonaffiliated Partner Trustee, and BJ Services Equipment, L.P., and State Street Bank and Trust Company, as Indenture Trustee (filed as Exhibit 10.17 to the Company's Annual Report on Form 10-K for the year ended September 30, 1997 (file no. 1-10570) and incorporated herein by reference).
10.32	Amended and Restated Agreement of Limited Partnership dated as of August 7, 1997 of BJ Services Equipment, L.P (filed as Exhibit 10.16 to the Company's Annual Report on Form 10-K for the year ended September 30, 1997 (file no. 1-10570) and incorporated herein by reference).
10.33	Trust Indenture and Security Agreement dated as of December 15, 1999 among First Security Trust Company of Nevada, BJ Services Equipment II, L.P. and State Street Bank and Trust Company, as Indenture Trustee (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K dated December 15, 1999 (file no. 1-10570) and incorporated herein by reference).
10.34	Amended and Restated Agreement of Agreement of Limited Partnership dated as of December 15, 1999 of BJ Services Equipment II, L.P. (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K dated December 15, 1999 (file no. 1-10570) and incorporated herein by reference).
†10.35	Amendment to Directors' Benefit Plan, effected January 1, 2003 (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2003 and incorporated herein by reference).
†10.36	Second Amendment, effective March 22, 2001, to BJ Services Company 1999 Employee Stock Purchase Plan (filed as Exhibit 10.40 to the Company's Annual Report on Form 10-K for the year ended September 30, 2003 and incorporated herein by reference).
†10.37	Fourth Amendment, effective December 4, 2003, to BJ Services Company 1999 Employee Stock Purchase Plan (filed as Exhibit 10.41 to the Company's Annual Report on Form 10-K for the year ended September 30, 2003 and incorporated herein by reference).
†10.38	First Amendment, effective September 25, 2003, to BJ Services Company Supplemental Executive Retirement Plan (filed as Exhibit 10.42 to the Company's Annual Report on Form 10-K for the year ended September 30, 2003 and incorporated herein by reference).
†10.39	BJ Services Company 2003 Incentive Plan (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended December 31, 2003 and incorporated herein by reference).
10.40	Credit Agreement, dated as of June 11, 2004 among the Company, the lenders from time to time party thereto, The Bank of New York and Citibank, N.A., as Co-Syndication Agents, The Royal Bank of Scotland plc and Bank One, N.A., as Co-Documentation Agents, and Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer (filed as Exhibit 10.44 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 and incorporated herein by reference).
†10.41	Form of Indemnification Agreement, dated as of December 9, 2004 between the Company and its directors and executive officers. (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K, filed on December 15, 2004, and incorporated herein by reference).
†10.42	Form of letter agreement setting forth terms and conditions of shares of phantom stock awarded to non-employee directors of the Company on November 17, 2004 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K, filed on November 23, 2004, and incorporated herein by reference).
†10.43	Form of letter agreement setting forth terms and conditions of performance units awarded to executive officers of the Company for performance in fiscal 2004 (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K, filed on November 23, 2004, and incorporated herein by reference).

Exhibit Number	Description of Exhibit
†10.44	Form of letter agreement setting forth terms and conditions of options to purchase shares of common stock awarded to non-employee directors on November 17, 2004 (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K, filed on November 23, 2004, and incorporated herein by reference).
†10.45	Form of letter agreement setting forth terms and conditions of options to purchase shares of common stock awarded to executive officers for performance in fiscal 2004 (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K, filed on November 23, 2004, and incorporated herein by reference).
†10.46	First Amendment to BJ Services Deferred Compensation Plan effective January 1, 2002 (filed as Exhibit 10.50 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 and incorporated herein by reference).
†10.47	Fifth Amendment to 1999 Employee Stock Purchase Plan, effective October 1, 2004 (filed as Exhibit 10.51 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 and incorporated herein by reference).
†10.48	Form of letter agreement setting forth terms and conditions of options to purchase shares of common stock awarded to non-employee directors during fiscal 2000 (filed as Exhibit 10.52 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 and incorporated herein by reference).
†10.49	Form of letter agreement setting forth terms and conditions of options to purchase shares of common stock awarded to non-employee directors during fiscal 2001 and 2003 (filed as Exhibit 10.53 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 and incorporated herein by reference).
†10.50	Form of letter agreement setting forth terms and conditions of options to purchase shares of common stock awarded to non-employee directors during fiscal 2004 (filed as Exhibit 10.54 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 and incorporated herein by reference).
†10.51	Form of letter agreement setting forth terms and conditions of options to purchase shares of common stock awarded to executive officers during fiscal 1997 (filed as Exhibit 10.55 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 and incorporated herein by reference).
†10.52	Form of letter agreement setting forth terms and conditions of options to purchase shares of common stock awarded to executive officers during fiscal 1998 (filed as Exhibit 10.56 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 and incorporated herein by reference).
†10.53	Form of letter agreement setting forth terms and conditions of options to purchase shares of common stock awarded to executive officers during fiscal 1999 (filed as Exhibit 10.57 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 and incorporated herein by reference).
†10.54	Form of letter agreement setting forth terms and conditions of options to purchase shares of common stock awarded to executive officers during fiscal 2001 (filed as Exhibit 10.58 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 and incorporated herein by reference).
†10.55	Form of letter agreement setting forth terms and conditions of options to purchase shares of common stock awarded to executive officers during fiscal 2002 (filed as Exhibit 10.59 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 and incorporated herein by reference).

Exhibit Number	Description of Exhibit
†10.56	Form of letter agreement setting forth terms and conditions of options to purchase shares of common stock awarded to executive officers during fiscal 2003 (filed as Exhibit 10.60 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 and incorporated herein by reference).
†10.57	Form of letter agreement setting forth terms and conditions of options to purchase shares of common stock awarded to executive officers during fiscal 2004 (filed as Exhibit 10.61 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 and incorporated herein by reference).
†10.58	Form of letter agreement setting forth terms and conditions of performance units awarded to executive officers during fiscal 2004 (filed as Exhibit 10.62 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 and incorporated herein by reference).
†10.59	Form of letter agreement setting forth terms and conditions of phantom stock awarded to non-employee directors during fiscal 2004 (filed as Exhibit 10.63 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 and incorporated herein by reference).
†10.60	BJ Services Company 2000 Incentive Plan—First Amendment to Terms and Conditions of Stock Options for Officers (filed as Exhibit 1.1 to the Company's Current Report on Form 8-K filed on March 29, 2006 and incorporated herein by reference).
†10.61	Form of letter agreement setting forth terms and conditions of options to purchase shares of common stock awarded to executive officers during fiscal 2007 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on November 21, 2006 and incorporated herein by reference).
†10.62	Form of letter agreement setting forth terms and conditions of options to purchase shares of common stock awarded to non-employee directors during fiscal 2007 (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed on November 21, 2006 and incorporated herein by reference).
†10.63	BJ Services Company 2000 Incentive Plan—Form of Second Amendment to Terms and Conditions of Stock Options for Officers (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K filed on November 21, 2006 and incorporated herein by reference).
*†10.64	Form of letter agreement setting forth terms and conditions of performance units awarded to executive officers during fiscal 2007.
*†10.65	Form of letter agreement setting forth terms and conditions of bonus stock awarded to executive officers during fiscal 2007.
*†10.66	Form of letter agreement setting forth terms and conditions of phantom stock awarded to executive officers during fiscal 2007.
*†10.67	Form of letter agreement setting forth terms and conditions of phantom stock awarded to non-employee directors during fiscal 2007.
*12.1	Ratio of Earnings to Fixed Charges.
14.1	Code of Ethics (filed as Exhibit 14.1 to the Company's Annual Report on Form 10-K for the year ended September 30, 2003 and incorporated herein by reference).
*21.1	Subsidiaries of the Company.
*23.1	Consent of Deloitte & Touche LLP.
*31.1	Section 302 certification for J. W. Stewart.
*31.2	Section 302 certification for Jeffrey E. Smith.
*32.1	Section 906 certification furnished for J. W. Stewart.

Exhibit Number	Description of Exhibit
*32.2	Section 906 certification furnished for Jeffrey E. Smith.
†99.1	Charter of the Nominating and Governance Committee of the Board of Directors (filed as Exhibit 10.43 to the Company's Annual Report on Form 10-K for the year ended September 30, 2003 and incorporated herein by reference).
†99.2	Charter of the Compensation Committee of the Board of Directors (filed as Exhibit 10.44 to the Company's Annual Report on Form 10-K for the year ended September 30, 2003 and incorporated herein by reference).
†99.3	Charter of the Audit Committee of the Board of Directors (filed as Exhibit 10.45 to the Company's Annual Report on Form 10-K for the year ended September 30, 2003 and incorporated herein by reference).
†99.4	Board of Directors Corporate Governance Guidelines (filed as Exhibit 10.46 to the Company's Annual Report on Form 10-K for the year ended September 30, 2003 and incorporated herein by reference).

* Filed herewith.

† Management contract or compensatory plan or arrangement.

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.

BJ SERVICES COMPANY

By ______________________
J. W. Stewart
President and Chief Executive Officer

Date: December 7, 2006

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
J.W. Stewart	Chairman of the Board, President, and Chief Executive Officer (Principal Executive Officer)	December 7, 2006
Jeffrey E. Smith	Vice President – Finance, and Chief Financial Officer (Principal Financial Officer)	December 7, 2006
Brian T. McCole	Controller (Principal Accounting Officer)	December 7, 2006
L. William Heiligbrodt	Director	December 7, 2006
John R. Huff	Director	December 7, 2006
Don D. Jordan	Director	December 7, 2006
William H. White	Director	December 7, 2006
Michael E. Patrick	Director	December 7, 2006
James L. Payne	Director	December 7, 2006

BJ SERVICES COMPANY

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended September 30, 2006, 2005 and 2004
(in thousands)

	Balance at Beginning Of Period	Additions: Charged to Expense	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
YEAR ENDED SEPTEMBER 30, 2006					
Allowance for doubtful accounts receivable	$13,938	$5,920	$3,228[4]	$(4,110)[1]	$18,976
Reserve for inventory obsolescence	17,429	3,031	4,002[4]	(2,090)[2]	22,372
YEAR ENDED SEPTEMBER 30, 2005					
Allowance for doubtful accounts receivable	$ 9,010	$6,811	$ 258	$(2,141)[1]	$13,938
Reserve for inventory obsolescence	16,144	5,667	(88)	(4,294)[2]	17,429
YEAR ENDED SEPTEMBER 30, 2004					
Allowance for doubtful accounts receivable	$ 8,828	$2,646	$ 55	$(2,519)[1]	$ 9,010
Reserve for inventory obsolescence	11,810	2,937	4,902[3]	(3,505)[2]	16,144

(1) Deductions in the allowance for doubtful accounts principally reflect the write-off of previously reserved accounts.

(2) Deductions in the reserve for inventory obsolescence and adjustment principally reflect the sale or disposal of related inventory.

(3) Reserve was previously netted against the inventory balance and an adjustment was made to reflect the gross amount of the reserve during fiscal 2004.

(4) Additions related to acquisitions.

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