2007 ANNUAL REPORT

BJ SERVICES COMPANY




A WORLD OF DIFFERENCE

## SELECTED HIGHLIGHTS

The Company's revenue increased 10% in fiscal 2007 versus fiscal 2006. All of our reporting segments, except Canada Pressure Pumping, contributed to our fiscal 2007 increase in revenue.

Operating income was $1,151 million in fiscal 2007 versus $1,172 million in fiscal 2006. Operating income margins remain strong at 24%. However, margins were hindered during the year by a 27% Canadian drilling activity decline, as well as pricing pressures in the U.S.

Cash flow from operating activities was $841 million. During the year, we invested more than $700 million in plant and equipment, paid $59 million dividends and purchased $75 million in Company stock.

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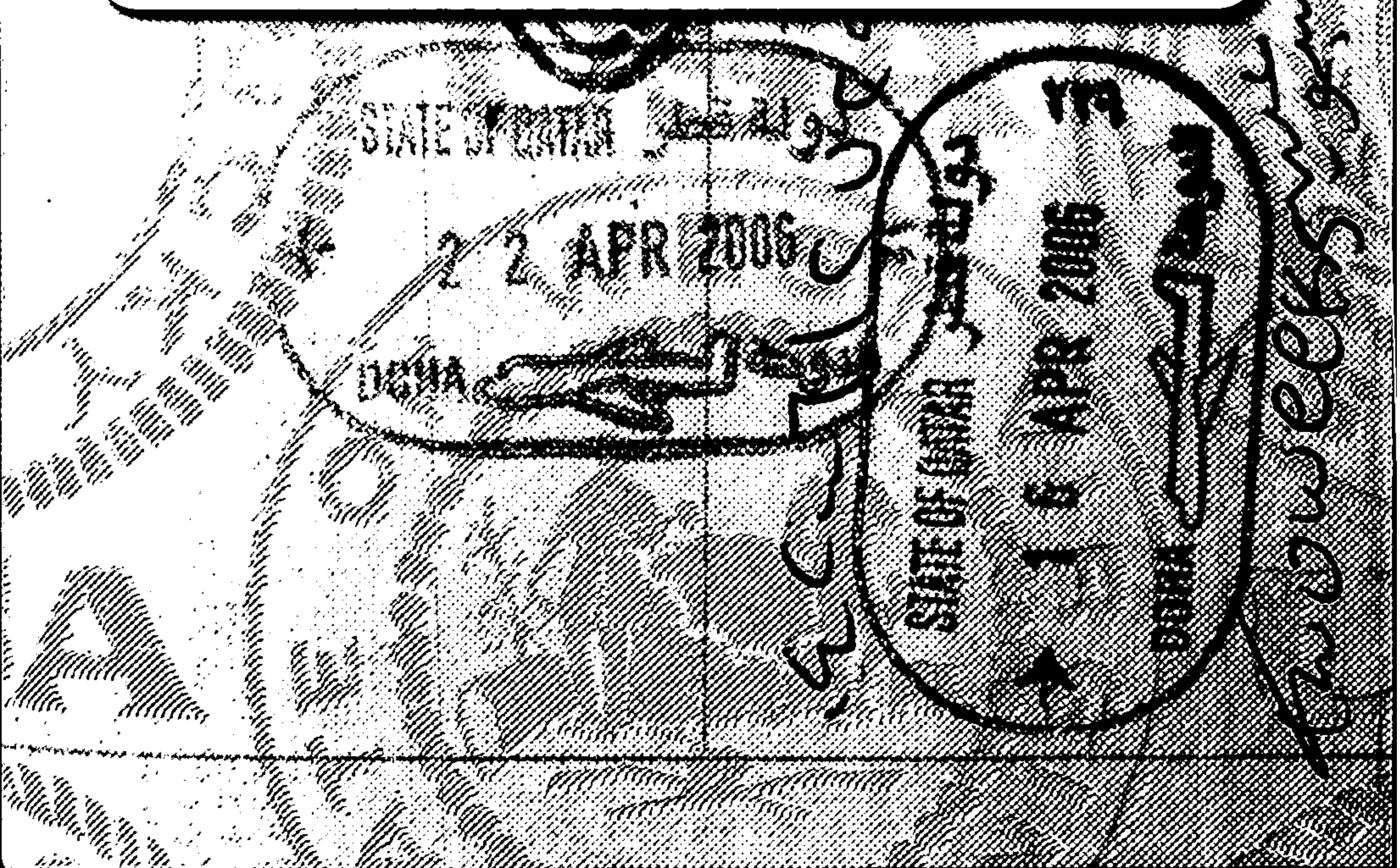
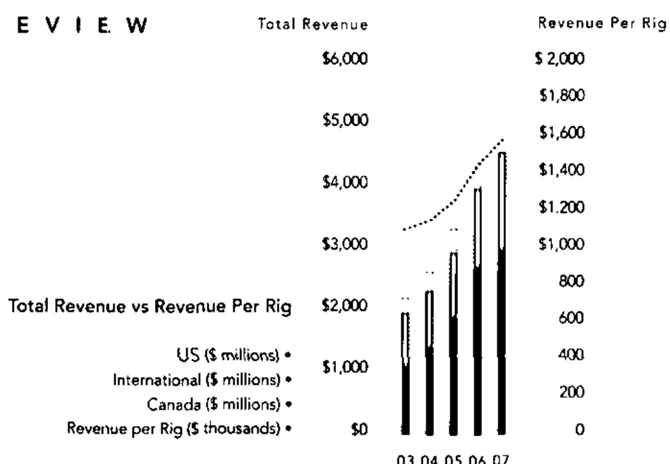
BJ Services Company is listed on the New York Stock Exchange, and its common stock trades under the symbol "BJS." The Company's core business consists of cementing, stimulation and coiled tubing services worldwide. The Company also provides completion tools, completion fluids, tubular services, chemical services, and pipeline and industrial commissioning and inspection services in selected geographic markets.

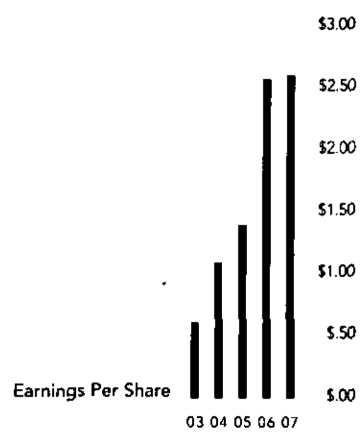


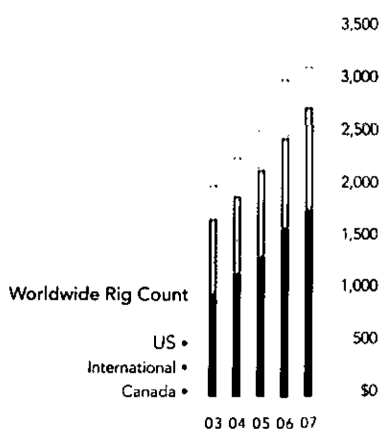
# Summary of Selected Financial Data

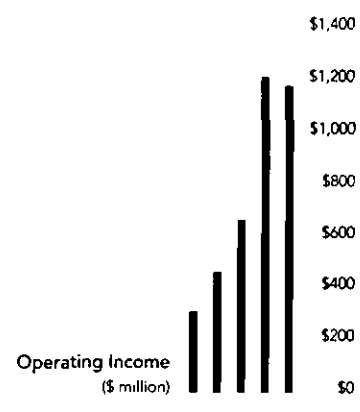
| (in thousands, except per share amounts) | 2007 | 2006 |
|---|---|---|
| Revenue | $4,802,409 | $4,367,864 |
| Operating income | 1,150,539 | 1,171,736 |
| Income before taxes | 1,112,848 | 1,172,083 |
| Net income | 753,640 | 804,610 |
| Basic earnings per share | 2.57 | 2.55 |
| Diluted earnings per share | 2.55 | 2.52 |
| Total assets | 4,715,212 | 3,862,288 |
| Total interest-bearing debt | 671,028 | 659,968 |
| Stockholders' equity | 2,851,398 | 2,146,940 |
| Capital expenditures | 752,113 | 459,974 |
| Employees | 16,700 | 16,000 |

## Year in Review




**The Company generated record revenue of $4.8 billion, up 10% from the prior year and earnings per diluted share was a record $2.55 up $.03 from the prior year. Cash flow from operations was $841 million and the Company's debt to capitalization at year-end was 19%.**

*Entries*
*Entrées /*

***Departures***
***Sorties / Salidas***

Simultaneous fracture stimulation of three shale gas wells.

Unconventional gas reservoirs present real challenges to the industry. A new technique we call "simo fracs" provides a unique, creative way to apply fracture stimulation treatments to wells in tight shale-gas formations in order to increase production. In this photo, BJ crews are simultaneously fracturing three adjacent horizontal wells in the Barnett Shale in North Texas. While the industry is far from perfecting gas extraction from shales, incremental changes like these make it easier to mobilize gas-in-place by imparting opposing hydraulic forces on multiple wells. This is a great example of BJ personnel using existing technologies to create new solutions for our customers.

The Company generated record revenue of $4.8 billion, up 10% from the prior year and earnings per diluted share was a record $2.55, up $.03 from the prior year. Cash flow from operations was $841 million and the Company's debt to capitalization at year-end was 19%. During the year, cash generated from operations was used for the investment of $704 million in plant and equipment for the business (excluding the $48 million purchase of partnership assets), payment of $59 million in dividends to our stockholders and the purchase of $75 million in Company Stock (2.6 million shares). Since the Company began its share repurchase program in 1997, the Company has repurchased 87 million shares for $1.8 billion, representing a 23% reduction in the number of shares that would have been outstanding as of September 30, 2007 without these repurchases.

## MARKET CONDITIONS

Natural gas prices for the year averaged $6.90 per thousand cubic feet. The price at the beginning of the year was $4.12 and was $6.14 at the end of the year. This price range was sufficient to maintain natural gas production in the U.S. market and support an average of just under 1,800 rigs drilling there. However, natural gas prices were generally lower in the Canadian market which led to a 27% decline in Canadian drilling activity compared to the prior year. Crude oil prices for the year averaged $64.62 per barrel. The price at the beginning of the year was $61.03 and was $81.66 at the end of the year. International politics and concern about supply disruptions coupled with significant demand growth in the emerging markets has propelled oil prices beyond our expectations.

Driven primarily by natural gas prices and crude oil prices, drilling activity in the U.S. was up 10% for the year. In Canada, drilling activity was down 27% from the prior year. Mexico experienced a 6% increase in average drilling activity. Outside North America, average drilling activity was up 10% from the prior year, with gains in each of our operating regions.

## PRESSURE PUMPING RESULTS

Pressure pumping service operations in U.S./Mexico achieved record revenue for the year with revenue up 9% from the prior year. Operating income margins were 34%, down from 38% in the prior year. As noted above, average drilling activity increased 10% in the U. S. and 6% in Mexico. Increased competition with modest activity growth resulted in lower prices which contributed to the margin compression compared to the prior year. Canadian pressure pumping revenue was down 20% from the prior year with average rig count down 27% and operating income was down 68% from the prior year. The Company reduced personnel and moved pressure pumping capacity out of Canada to better align ourselves with the market demand. We have decreased personnel in Canada by 19%, transferred pumping equipment capacity to other international locations and changed reporting lines. The U.S. and Canadian markets are similar with many independent customers, short term contracts and volatile drilling activity. We now have one management team over North American pressure pumping. We continue to focus on labor cost efficiencies as well as labor and equipment utilization and maintain tight controls over discretionary spending. We expect to realize favorable year over year earnings comparisons from our Canadian operations as we move into fiscal year 2008.

Outside North America, drilling activity increased 10% and our international pressure pumping operations achieved 21% revenue growth and 11% increase in operating income. During the year, we restructured our Russia operations. We sold our workover rig business there to focus on our pressure pumping business and we reduced personnel by 38% compared to fiscal 2006. Similar to Canada, we are transferring excess capacity to other international markets. In Africa, we have exited smaller countries and will focus our efforts in Libya, Algeria and Nigeria.

## OILFIELD SERVICE GROUP RESULTS

The Oilfield Service Group had an exceptionally good year. Revenue for the group was up 20% and operating income improved by 24%. Each of the service lines except Completion Fluids experienced double-digit revenue growth with Chemical Services and Tubular Services achieving greater than 30% revenue growth. Completion Fluids was adversely impacted by significantly reduced activity in the Gulf of Mexico. We continue to integrate the Group service and product offerings throughout our global operations and with revenue of $778 million for the year, the Oilfield Service Group is making a material contribution to the Company's financial results.

## EXPANSIONS

**International Pressure Pumping** – The Latin America region continued to experience significant growth as revenue increased by 21% compared to the prior year. Much of the growth in the region is a result of expanding our stimulation capacity. Revenue growth was fueled by the addition of fracturing assets in Argentina, Colombia and Brazil. We are a stimulation market leader in Latin America and will further advance this position through the award of several new contracts in 2007. Most significantly, our award of a new stimulation vessel contract for the Blue Angel, our award of a new stimulation vessel contract for a new vessel, the Blue Marlin, and the existing stimulation vessel contract for the Blue Shark will position BJ as a major offshore fracturing company in Brazil.

The business in India was greatly enhanced in late 2007 as a result of two offshore stimulation vessel contracts awarded to BJ. The MV Vestfonn was transferred from the North Sea to India to perform services under a three-year contract. In addition, the MV Discovery was transferred from the Gulf of Mexico to India to perform services under a two-year contract. These significant contract awards position the Company to participate in the growing offshore stimulation market in India for many years.

The Asia Pacific Region experienced a second consecutive year of over 25% revenue growth during 2007. Driving this revenue growth is the expansion of hydraulic fracturing throughout the region. We placed our first permanent frac fleet in Australia during 2007 and immediately had success in the market. We were awarded a five year offshore


New InjectSafe™ chemical injection system for offshore wells

BJ acquired Dyna-Coil™ capillary tubing technology late in fiscal 2006 and successfully moved this technology offshore during fiscal 2007 with the first installations of our InjectSafe™ systems. These systems deliver high-efficiency chemicals deep inside offshore gas wells, giving operators a mean to "unload" liquid and extend well life more reliably and economically. The Dyna-Coil acquisition and our purchase of Allis-Chalmers' capillary assets in 2007 gave BJ more than 7,000 land-based capillary installations, the largest fleet of capillary service equipment -- and the most advanced 'cap string' capabilities in the world.

stimulation contract in China during 2007 which involves BJ skid mounted fracturing equipment on a vessel and will be the only stimulation vessel operating offshore China.

**Chemical Services** – Chemical Services realized a second consecutive year of revenue growth in excess of 35%, driven by growth in traditional chemical services, growth in capillary services and geographic expansion. In 2007, we developed a new revenue base in the Northeast U.S. with the introduction of our LiteChem™ well treating chemicals and services. This proprietary technology was developed for production chemical applications in very low pressure wells and has had tremendous success in improving chemical treatment of downhole tubulars. In addition, we have received several new contracts internationally which will fuel continued geographic expansion of the chemical services product line.

Following the acquisition of Dyna-Coil in the last quarter of fiscal 2006, capillary services has become a significant contributor to revenue growth for Chemical Services and an important vehicle for gaining production chemical business. In July 2007, we expanded our capillary services capacity through the acquisition of Allis-Chalmers' capillary assets. Capillary services are now being conducted in the Asia Pacific Region as well as North America.

**Tubular Services** – Tubular Services continued with aggressive revenue growth and geographic expansion during 2007. Overall revenue increased 30% from 2006, driven by market expansion in several of our traditional operating countries such as Saudi Arabia, Brazil and the U.K. and expansion into new markets in Brunei, Malaysia and Norway. The division increased capital spending during the year to fuel revenue growth opportunities in 2007 and beyond.

**Completion Tools** – Completion Tools revenue increased 28% in 2007, driven by significant growth in international revenue. Since the acquisition of OSCA, Inc. in 2002, the Gulf of Mexico market (OSCA's primary market) has experienced steady deterioration. However, we have been able to significantly expand the revenue in this division through international expansion and through new product offerings.

In 2007, we relocated our completion tool component manufacturing facility from Mansfield, Texas, to Houston and increased our manufacturing capacity by 50%. This capacity increase will support further revenue expansion in completion tools and reduce our overall component production cost.

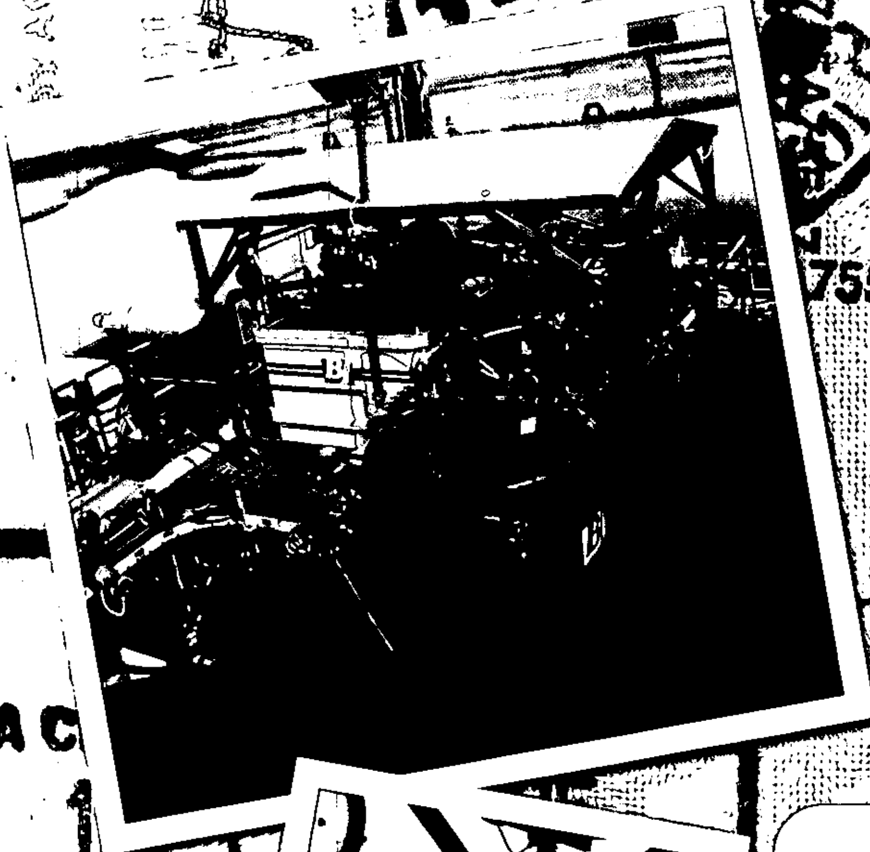
**Completion Fluids** – The operating results for the completion fluids business has historically been impacted by demand for and pricing of high-density brines used in offshore well completions. In recent years, our strategy has been to obtain improved margin revenue from products and services that are ancillary to completion fluid sales. These ancillary services include wellbore clean-out services, lost circulation services and specialty chemicals.

In 2007, we completed the acquisition of Tekcor Technology, Ltd. ("Tekcor"), a company that specialized in a unique lost circulation control technology. Since the acquisition, we have expanded the capacity of the TekTote® delivering systems for our TekPlug® fluid loss control products by 50% and expect to double our revenue in this new product line during 2008.

**Process and Pipeline Services** – Process and Pipeline Services had a very successful year with revenue up 21% for the year and operating income improving by 23% . These

**Coiled tubing fracturing for wells in multi-zone reservoirs**

Coiled tubing fracturing is emerging as an effective, economical method for stimulating production from multi-zone reservoirs and BJ Services is at the forefront of this technological trend. Coiled tubing offers an especially efficient means for re-entering older wells to boost production and postpone their abandonment. At the Developing Unconventional Gas (DUG) conference this year, one operator credited our OptiFrac™ coiled tubing fracturing services for helping them "crack the code" for stimulating the Hosston trend, multiple thin productive zones bypassed when the industry drilled deeper Cotton Valley wells in east Texas and Louisiana years ago. Now BJ technology is extending the life of these fields for years to come.



New-generation BJ Seahawk™ offshore cementing unit

Oil and gas reserves from deepwater plays are increasingly important for both major international operators and national oil companies. BJ Services recorded a nearly 50% increase in deepwater activity during fiscal 2007. BJ is now the second leading provider of cementing units in the Gulf of Mexico, and we achieved early success placing our new-generation Seahawk™ offshore cement mixing units aboard dozens of semi-submersible and jack-up drilling rigs and drillships during 2007. These rigs are due to leave shipyards in 2008 and 2009, so our Seahawk placements promise to provide steady revenue from cementing services for both deepwater and deep shelf drilling in the years ahead.

results are records for the division.

In 2007, we had two acquisitions that added to our process and pipeline business line. In our first fiscal quarter, we completed the acquisition of Profile International Ltd., which provides caliper inspection tools for pipeline integrity assessment to markets worldwide.

We also acquired Aberdeen-based Norson Services Ltd. ("Norson") during our second fiscal quarter. This acquisition strengthens our service capabilities with the addition of hydraulic and electrical umbilical testing services and the services provided by Norson's subsea units, which include remote pigging and flooding and subsea pressure testing.

## 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 include extreme pressure and temperature conditions, fragile formations, shallow water flow and many other extreme subterranean conditions. They are also challenged by regulations and our desire to protect and prevent damage to the environment with the products we use.

Our technology development efforts have been focused in the technical areas that are most challenging to our customers. Those challenges can best be summarized as i) unconventional reservoirs, ii) mature fields, iii) harsh environments and iv) multi-zone completions.

**Unconventional Reservoir Development** - Hydraulic fracturing is the single most critical technology employed in the development of unconventional gas reservoirs. As a leader in hydraulic fracturing, BJ has been instrumental in developing a variety of product technologies and application techniques to improve production performance in unconventional gas reservoirs.

LiteProp™ 108 is the latest in a series of ultra-lightweight (ULW) proppants developed for use in unconventional reservoirs. These proprietary ULW proppants are capable of being carried more efficiently through the entire fracture length of a hydraulically induced fracture and provide the possibility of partial monolayer fractures, the theoretically optimum fracture. The LiteProp products are also now available in a liquid concentrate version called Liquid LiteProp, which provides for operational and economic efficiencies on well locations.

BJ has also been instrumental in refining a technique currently in use in the gas shale formations known as "simo frac". This technique involves the simultaneous fracturing of adjacent wellbores, whereby opposing forces are used to optimize natural gas liberation in gas shale reservoirs. The equipment and operational intensity involved in these treatments can most effectively be carried out by a premier fracturing company.

**Mature Field Production Enhancement** - Older oil and gas fields represent a huge challenge to our customers to extend the productive life of existing wells and capitalize on strong commodity prices. Our customers depend on ever improved solutions to their production challenges in these mature fields and BJ has introduced a variety of new solutions for problems typically experienced in older oil and gas fields.

Our StimTunnel™ technique, originally developed by BJ in Latin America, involves the use of coiled tubing and specialized stimulation fluids to create lateral extensions from existing open hole completions. The chemicals are injected through the coiled tubing and dissolve targeted areas of the formation to create short radius extensions from the wellbore thereby improving well production.

The introduction of capillary services has given us the opportunity to develop a variety of chemical solutions for use in treating production problems in older wells. A primary use of capillary systems has been to inject foam-generating chemicals to lift fluid from low-pressure gas wells. Unique chemistry and engineering is required to provide cost effective solutions in de-watering these low pressure gas wells and new solutions are constantly being developed for providing chemical solutions through these capillary strings.

**Harsh Environment Well Construction and Completion** - The deepwater work environment creates exceptional challenges in wellbore cementing. We have had great success in customizing our DeepSet™ and LiteSet™ cementing systems to meet the extreme conditions that are encountered in deepwater cementing.

Our acquisition of Tekcor this year also provides BJ customers with an extremely effective solution for lost circulation problems in their offshore wells. Our TekPlug® fluid loss products, delivered through the unique TekTote® delivery system, provide our customers with an immediate solution when they encounter lost returns during completion operations.

**Multi-Zone Completion Techniques** - Economics and effectiveness are the key drivers for our customers that pursue multi-zone completions. BJ has developed a series of technologies to address the very difficult challenges associated with these completions.

Last year, we introduced the ComPlete™ MST system for use in sand control applications. This system, which provides zonal isolation for single trip frac packing of individual zones in a multi-zone completion, has been extremely well received by our customers. From the Gulf of Mexico to Asia, operators are selecting this system for their most critical applications.

Multi-zone completions have also become important for our customers that are exploiting unconventional gas formations. The OptiFrac™ system and DirectStim™ system are two new mechanical techniques for isolating zones during hydraulic fracturing in order to target specific zones for stimulation.

## 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 operating equipment. The plan for the year was to build $700 million in additional plant and equipment. Capital was allocated across service lines based on maintenance capital needs and the best growth opportunities. Equipment was produced at our three main manufacturing facilities in Houston, Calgary and Singapore and by outside suppliers. We achieved our planned asset additions for the year, a substantial increase over the prior year and a great achievement for our manufacturing personnel throughout the world.

Incorporated within our manufacturing and marketing strategy was a focus on equipping the large volume of new and rebuilt offshore rigs with BJ cementing equipment. During the course of 2007 and 2008 there will be an influx of new offshore rigs to the marketplace. BJ has focused a sales and manufacturing effort to capitalize on these new rigs.

The introduction of Singapore as our sole manufacturing facility for the new generation Seahawk™ cement unit and the concentrated effort of our engineering, installation and sales organization has resulted in a significant number of new offshore cementing opportunities for the Company. We should realize the results of this effort during 2008/2009 as these new rigs arrive in the field and begin generating revenue for the Company.

## MARKET OUTLOOK

The implications of the credit crisis throughout the world is not yet known, consequently making growth projections for the new year difficult at best. Our plan assumes positive economic growth in the world markets but at a somewhat lower rate of growth than the year just ended. Drilling activity in the U.S. is projected to be up slightly for the year. The addition of new fracturing capacity to the U.S. market by industry participants should begin to abate in the second half of the year. We base our expectations on statements of company management, the tightness in the credit markets and margin compression experienced in the business. In Canada, activity is expected to be up 10% to 15% in the year and our earnings should improve there due to the restructuring done in the year just ended. The international markets are expected to grow in the range of 15% to 20% and we expect to achieve revenue growth in that range with margin improvement. The Oilfield Service Group should have another good year with revenue improvement and good earnings generation. Our capital spending for the year is planned to be down 10% from the prior year with more emphasis on the international markets and the Oilfield Service Group where we expect the better growth opportunities.

J. W. Stewart
Chairman, President and
Chief Executive Officer
December 7, 2007

## Corporate Officers

BJ Services Company Officers, December 2007— left to right, **J. W. Stewart**, Chairman of the Board, President and Chief Executive Officer; **Bret Wells**, Vice President–Treasurer and Chief Tax Officer; **Alasdair Buchanan**, Vice President – International Pressure Pumping Services; **Margaret B. Shannon**, Vice President – General Counsel; **Paul Yust**, Vice President – Chief Information Officer; **David Dunlap**, Executive Vice President – Chief Operating Officer; **L. Scott Biar**, Vice President – Controller; **Ronald F. Coleman**, Vice President – North America Pressure Pumping Services; **Jeffrey E. Smith**, Senior Vice President – Finance and Chief Financial Officer; and **Susan Douget**, Vice President – Human Resources. Not pictured: **Jeff Hibbeler**, Vice President – Technology and Logistics.

## Board of Directors

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

**John R. Huff*‡**
Chairman 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

# 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, 2007**

**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 26, 2007, the registrant had outstanding 292,825,124 shares of Common Stock, $.10 par value per share. The aggregate market value of the Common Stock on March 31, 2007 (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 $8.2 billion.

**DOCUMENTS INCORPORATED BY REFERENCE:**

Portions of the registrant's Proxy Statement for the Annual Meeting of Stockholders to be held February 7, 2008 are incorporated by reference into 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, chemical services, and precommissioning, maintenance and turnaround services in the pipeline and process business, including pipeline inspection.

During the year ended September 30, 2007, we generated approximately 84% of our revenue from pressure pumping services and 16% 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, 2007, 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, 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 31% of total pressure pumping revenue during fiscal 2007, 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 2007, 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 since expanded the U.S. fleet recapitalization initiative to include additional equipment, such as cementing, nitrogen and acidizing equipment and have made significant progress in adding new equipment. However, much of the older equipment still remains in operation due to increased market activity. We plan to continue adding new equipment to our fleet. The market activity level at the time the equipment is ready for use will determine if the new equipment will be used for expansion or used as replacement assets. At the end of fiscal 2007, approximately 20% of our U.S. fleet remained as candidates for future replacement as part of our recapitalization initiative.

*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. Coiled tubing is a flexible steel pipe with a diameter of less than five inches manufactured in continuous lengths of thousands of feet. It 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 16% of our total revenue in fiscal 2007. This segment consists of casing and tubular services, process and pipeline services, chemical services, 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.

*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: (1) the precommissioning of new plants and (2) 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.

Due to regulatory requirements or safety concerns, new pipelines are often tested prior to their initial use. During fiscal 2007, we added subsea umbilical and pipeline testing capability through the acquisition of Norson Services Limited. 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, which include 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 electromagnetic devices that are propelled through a pipeline, recording information about the pipeline. We have developed two principal sets of pipeline inspection tools: one set of tools monitors metal loss from the interior pipe wall caused by either corrosion or mechanical damage utilizing electromagnetic based instruments. A second set of tools monitor 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.

*Chemical Services*

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) through the acquisitions of Dyna-Coil in August 2006 and the capillary string business of Allis-Chalmers in June 2007, the 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 production packers, surface controlled subsurface safety valves, and other tools that are delivered through distribution networks located in key domestic markets and select international markets.

We have 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. In addition, we provide a wide range of downhole tools with chemical systems for removing drilling fluid debris from a well during completion operations.

With the acquisition of Tekcor Technology, Ltd. in December 2006 we entered into the business of providing a unique system for delivery of lost circulation materials used in conjunction with completion operations.

**Raw Materials and Equipment**

Principal materials used in pressure pumping include cement, fracturing proppants, acid, polymers, nitrogen, and other specialty 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 continued to experience 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 certain levels 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. 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. 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 Support

Our engineering support department is divided into the following areas: Software Applications, Instrumentation Engineering, Mechanical Engineering, Coiled Tubing Engineering and Completion Tools Engineering.

### *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*

Our mechanical engineering group is responsible for the design of virtually all of our primary pumping and blending equipment. 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.

*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 design, manufacture 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 technology center in Tomball, Texas houses our main equipment manufacturing facility, primarily serving pressure pumping services. Our other facility in the Houston, Texas area produces certain components and spare parts required for the assembly of downhole completion tools, service tools and well screens. We also have strategic manufacturing facilities located in Calgary and Singapore to support our global manufacturing efforts. 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. We also compete with Weatherford International, Inc. and numerous smaller companies including Calfrac Well Services Ltd., Trican Well Service Ltd., San Antonio and Frac Tech Services, Ltd. During 2007, we have experienced increased competition in the U.S. market from these and other new competitors. 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. 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 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; 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 2007, 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 1,749 in fiscal 2007, a 10% increase over the fiscal 2006 average U.S. rig count of 1,587. In fiscal 2006, the average U.S. rig count was 20% higher than the fiscal 2005 U.S. rig count average of 1,323.

*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 989 in fiscal 2007, a 9% increase over the fiscal 2006 average international rig count of 905. In fiscal 2006, the average international rig count was 9% higher than the fiscal 2005 international rig count average of 833.

In fiscal 2005, we opened an office in Libya 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. Also in fiscal 2006, operating bases in New Zealand, Uzbekistan and Oman were opened. In fiscal 2007, we began operation of stimulation vessels in India and began fracturing work in Australia.

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. in that demand for our pressure pumping services 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 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 2007, the average rig count was 365, 27% lower than the fiscal 2006 rig count average. The results of operations in Canada are impacted by seasonality during Canadian spring break-up. During the annual spring break-up, typically our third fiscal quarter, this region experiences a significant decline in revenue and operating income.

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 dollars. 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, 2007, we employed approximately 16,700 personnel around the world. Approximately 59% of our employees were employed outside the United States. As we experience expanding activity levels in certain markets, 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 on a worldwide basis 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 both inside and outside of the U.S. having 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, 2007, see Note 12 of the Notes to the Consolidated Financial Statements.

Some of our key patented and patent pending technologies include:

(1) fracturing fluids, such as our high-performance SPECTRA FRAC G® and low-polymer loading VISTAR®;

(2) our LITE PROP® low-density proppants capable of producing 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;

(3) water control systems for reducing undesirable water production while increasing oil or natural gas production using our relative water permeability modifier, AQUACON™;

(4) well cleanout systems, including the TORNADO® and SANDVAC® systems, effective at removing sand and other fill material from wells at much greater efficiencies than previously obtainable;

(5) surface-controlled sub-surface safety valves, including our FLOWSAFE™ WR wireline-retrievable and FLOWSAFE™ TR tubing-retrievable valves;

(6) completion tool systems for conventional completions and horizontal well completions in both gravel-packed and conventional configuration, and interventionless intelligent completion systems; and

(7) our 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 to allow continuous chemical treatment up to 22,000 feet (6,700 meters) below the safety valve without interruption or risk to the safety valve.

### 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 | 63 | Chairman of the Board, President and Chief Executive Officer | 1990 |
| Alasdair Buchanan | 47 | Vice President—International Pressure Pumping Services | 2007 |
| Ronald F. Coleman | 52 | Vice President—North America Pressure Pumping Services | 2007 |
| Susan Douget | 47 | Vice President—Human Resources | 2003 |
| David Dunlap | 46 | Executive Vice President—Chief Operating Officer | 2007 |
| Jeff Hibbeler | 42 | Vice President—Technology and Logistics | 2007 |
| Brian T. McCole | 48 | Vice President—Controller | 2002 |
| Margaret B. Shannon | 58 | Vice President—General Counsel | 1994 |
| Jeffrey E. Smith | 45 | Senior Vice President—Finance and Chief Financial Officer | 2006 |
| Bret Wells | 42 | Vice President—Treasurer and Chief Tax Officer | 2006 |
| Paul Yust | 54 | Vice President—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—International Pressure Pumping Services in 2007. He served as Vice President—Technology and Logistics from 2005 through 2007 and 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.

Mr. Coleman joined the Company in 1977 and was named Vice President—North American Pressure Pumping Services in 2007. Prior to be promoted to Vice President—North America Pressure Pumping Services, he held the position of Vice President U.S./Mexico Operations from 1998 through 2007. He previously held various management positions within U.S./Mexico sales and operations.

Ms. Douget joined the Company in 1979 and was promoted to Director, Human Resources in 2003 and then to Vice President in 2007. 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 Executive Vice President—Chief Operating Officer in 2007. Prior to being promoted to Executive Vice President and Chief Operating

Officer, he held the position of Vice President—International Division from 1995 through 2007. He also previously served as Vice President—Sales for the Coastal Division of North America and U.S. Sales and Marketing Manager.

Mr. Hibbeler joined the Company in 1989 as an Associate Engineer and was named Vice President—Technology and Logistics in 2007. He has previously served as Region Manager for Asia Pacific. Prior to that, he held the position of Country Manager for several countries in Asia Pacific and Latin America.

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 and was promoted to Vice President in 2007.

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. In 2007, Mr. Smith was promoted to Senior Vice President.

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 and was promoted to Vice President in 2007.

Mr. Yust joined the Company as Chief Information Officer in 2006 and was promoted to Vice President in 2007. 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 grow businesses we have acquired such that our investment can be fully realized
- 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, including the addition of new competitors and new capacity in the U.S.,
- 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, oil spills and leaks or spills of hazardous materials. 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 an pipeline business, as a result of work performed by us at petrochemical plants as well as on pipelines.

**Risks from 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 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 and our competitive position 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

We 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 strategic manufacturing facilities to support our global manufacturing efforts located in Calgary and Singapore.

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, 2007.

## PART II

### ITEM 5. Market For Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock began trading on The New York Stock Exchange ("NYSE") in July 1990 under the symbol "BJS". At November 26, 2007, there were approximately 1,342 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.

| | Common Stock Price Range | |
|---|---|---|
| | High | Low |
| Fiscal 2007 | | |
| 1st Quarter | $34.14 | $27.43 |
| 2nd Quarter | 29.10 | 25.55 |
| 3rd Quarter | 31.26 | 27.25 |
| 4th Quarter | 29.52 | 23.48 |
| 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 |

At September 30, 2007, there were 347,510,648 shares of common stock issued and 291,735,636 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.

#### 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 was increased 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 52,348,000 shares at a cost of $597.4 million through fiscal 2005. During fiscal 2006, we purchased a total of 31,725,882 shares at a cost of $1,133.3 million. During fiscal 2007, we purchased a total of 2,564,457 shares at a cost of $74.6 million. We currently have remaining authorization to purchase up to an additional $394.7 million in stock.

We made no purchases of equity securities during the quarter ended September 30, 2007.

#### Dividend Program

We have paid cash dividends in the amount of $.05 per common share each quarter for fiscal years 2006 and 2007. We anticipate paying cash dividends in the amount of $.05 per common share on a quarterly basis in fiscal 2008. 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.

**Performance Graph—Total Stockholder Return**

The following is a line graph comparing cumulative, five-year total shareholder return with a general market index (the S&P 500) and a group of peers in the same line of business or industry selected by the Company. The peer group is comprised of the following companies: Baker Hughes Incorporated, Halliburton Company, Schlumberger N.V., Smith International, Inc., and Weatherford International Ltd.

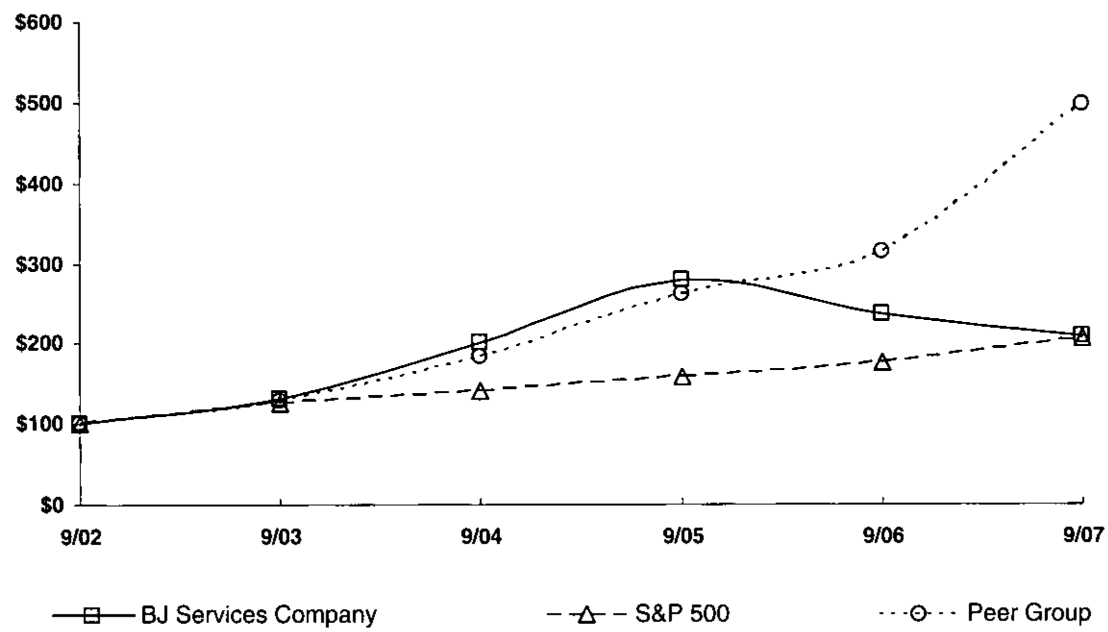
The graph assumes investments of $100 on September 30, 2002 and the reinvestment of all dividends.

The graph shall not be deemed incorporated by reference by any general statement incorporating by reference this Form 10-K into any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, except to the extent that the Company specifically incorporates this information by reference, and shall not otherwise be deemed filed under such Acts.

**COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN**

Among BJ Services Company, The S&P 500 Index

And A Peer Group



## 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, 2007 have been derived from our audited consolidated financial statements, some of which appear elsewhere in this Annual Report on Form 10-K. Our historical results are not necessarily indicative of results to be expected in future periods.

| | As of and For the Year Ended September 30, | | | | |
|---|---|---|---|---|---|
| | 2007 | 2006 | 2005 | 2004 | 2003 |
| | (in thousands, except per share amounts) | | | | |
| **Operating Data** | | | | | |
| Revenue | $ 4,802,409 | $ 4,367,864 | $ 3,243,186 | $ 2,600,986 | $ 2,142,877 |
| Operating expenses | (3,651,870) | (3,196,128) | (2,606,127) | (2,162,601) | (1,849,636) |
| Operating income | 1,150,539 | 1,171,736 | 637,059 | 438,385 | 293,241 |
| Interest expense | (32,731) | (14,558) | (10,951) | (16,389) | (15,948) |
| Interest income | 1,624 | 14,916 | 11,281 | 6,073 | 2,141 |
| Other income (expense), net[1] | (6,584) | (11) | 15,958 | 92,668 | (3,762) |
| Income tax expense | (359,208) | (367,473) | (200,305) | (159,696) | (87,495) |
| Net income | 753,640 | 804,610 | 453,042 | 361,041 | 188,177 |
| Earnings per share[2]: | | | | | |
| Basic | 2.57 | 2.55 | 1.40 | 1.13 | .60 |
| Diluted | 2.55 | 2.52 | 1.38 | 1.10 | .58 |
| Depreciation and amortization | 209,019 | 166,763 | 136,861 | 125,668 | 120,213 |
| Capital expenditures[3] | 752,113 | 459,974 | 323,763 | 200,577 | 167,183 |
| **Financial Position Data (at end of period):** | | | | | |
| Property, net | $ 1,965,719 | $ 1,392,926 | $ 1,086,932 | $ 913,713 | $ 850,340 |
| Total assets | 4,715,212 | 3,862,288 | 3,409,642 | 3,301,330 | 2,800,135 |
| Long-term debt and capital leases, excluding current maturities | 252,709 | 500,140 | 455 | 78,936 | 493,754 |
| Stockholders' equity | 2,851,398 | 2,146,940 | 2,492,041 | 2,102,424 | 1,658,920 |
| Cash dividends declared per common share | .20 | .20 | .17 | .04 | |

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

(2) 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.

(3) Excluding acquisitions of businesses. Includes $47.8 million in fiscal 2007 to purchase assets from an equipment financing partnership. See Note 10 of the Notes to the Consolidated Financial Statements.

## 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 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:

| | 2007 | % Change | 2006 | % Change | 2005 |
|---|---|---|---|---|---|
| Worldwide Rig Count[1]: | | | | | |
| U.S. | 1,749 | 10% | 1,587 | 20% | 1,323 |
| International[2] | 989 | 9% | 905 | 9% | 833 |
| Canada | 365 | -27% | 502 | 20% | 420 |
| Commodity Prices (average): | | | | | |
| Crude Oil (West Texas Intermediate) | $64.62 | -2% | $66.06 | 23% | $53.52 |
| Natural Gas (Henry Hub) | $ 6.90 | -15% | $ 8.16 | 10% | $ 7.40 |

(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 90, 85 and 111 for the fiscal years ended September 30, 2007, 2006 and 2005, respectively.

*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 1,749 in fiscal 2007.

*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 and including Mexico, averaged 616 in fiscal 1999 and the highest annual international rig count averaged 989 in fiscal 2007.

*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**

*Fiscal 2007*

On November 3, 2006, we completed the acquisition of Profile International Ltd. ("Profile") for a total purchase price of $2.5 million, which resulted in $2.2 million of goodwill. Profile, located in Newcastle, England, provides caliper inspection tools for pipeline integrity assessment to markets worldwide. This business complements our pipeline inspection business in the Oilfield Services Group segment.

On December 20, 2006, we purchased substantially all of the operating assets of Tekcor Technology, Ltd. ("Tekcor") for $8.3 million, which resulted in an increase of $3.6 million to total current assets, $0.7 million in property and equipment and $4.0 million to technology based intangible assets. Tekcor provides specialty chemicals and related services to the oil and gas well drilling industry. Located in Houston, Texas, Tekcor services markets along the Texas and Louisiana Gulf Coast and is included in our completion fluids business in the Oilfield Services Group segment.

On March 1, 2007 we acquired Aberdeen-based Norson Services Ltd, ("Norson"), a division of Norson Group Ltd., and substantially all of the assets of Norson Group's United States subsidiary Norson Services LLC. The total purchase price paid for both acquisitions was $29.0 million, including legal fees, which resulted in an increase of $7.4 million in total current assets, $5.9 million in property and equipment, $1.8 million in intangible assets, $5.4 million in current liabilities and $19.3 million of goodwill. The acquisition strengthens our service capabilities with the addition of Norson's hydraulic and electrical umbilical testing services and the services provided by the Norson's subsea units, which include remote pigging and flooding, subsea hydro testing and subsea data logging. This business complements our process and pipeline business in the Oilfield Services Group segment.

On June 30, 2007, we completed the acquisition of substantially all of the capillary tubing assets of Allis-Chalmers for a total purchase price of $16.3 million, which resulted in an increase of $1.5 million in current assets, $1.8 in property and equipment and $13.0 million of goodwill. The assets are used for the installation and service of capillary injection systems primarily in the U.S. and Mexico. The assets complement our Dyna-Coil acquisition which occurred in the fourth quarter of fiscal 2006 and will enhance our chemical services operation in the Oilfield Services Group segment.

*Fiscal 2006*

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, fracturing 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 was accounted for as a step-acquisition, we have control of BJSP and 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*, in 2006, we 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. 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.

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 chemical services business in the Oilfield Services Group 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 currently in the process of completing our review and determination of the fair values of the assets acquired from Norson and Allis-Chalmers. Accordingly, allocation of the purchase price is subject to revision based on final determination of the asset values. Pro forma financial information for our fiscal 2007 and fiscal 2006 acquisitions is not included as they were not material individually or in aggregate to our financial statements.

## Results of Operations

***Consolidated (in millions)***

| | 2007 | % Change | 2006 | % Change | 2005 |
|---|---|---|---|---|---|
| Revenue | $4,802.4 | 10% | $4,367.9 | 35% | $3,243.2 |
| Operating income | $1,150.5 | -2% | $1,171.7 | 84% | $ 637.1 |
| Worldwide rig count[1] | 3,103 | 4% | 2,995 | 16% | 2,576 |

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

*Results for fiscal 2007 compared to fiscal 2006*

All of our reportable segments, except Canada, contributed to the increase in revenue for fiscal 2007 when compared to fiscal 2006. The increase primarily relates to higher activity in all major markets except Canada, where depressed market conditions were present throughout fiscal 2007. Worldwide average active drilling rigs for fiscal 2007 increased 4% compared to the prior year.

Fiscal 2007 consolidated operating income was 24%, a 2% decrease compared to fiscal 2006. Operating income margin was negatively impacted by a 68% decline in operating income from Canada as well as price reductions in the U.S. market.

*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.

***U.S./Mexico Pressure Pumping Segment (in millions)***

| | 2007 | % Change | 2006 | % Change | 2005 |
|---|---|---|---|---|---|
| Revenue | $2,562.7 | 9% | $2,353.8 | 40% | $1,683.2 |
| Operating income | $ 881.6 | -2% | $ 899.2 | 71% | 524.9 |
| U.S. rig count[1] | 1,749 | 10% | 1,587 | 20% | 1,323 |
| Mexico rig count[1] | 90 | 6% | 85 | -23% | 111 |

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

*Results for fiscal 2007 compared to fiscal 2006*

Fiscal 2007 U.S./Mexico revenue increased compared to the prior year as the result of activity increases most notably in East Texas, Permian Basin, and Northeast regions of the United States. The Mexico region also benefited from improved revenues attributable to the expansion of our business in southern Mexico. These increases were slightly offset by a decline in activity in the Pacific region. While the U.S./Mexico average active drilling rigs increased 10% for fiscal 2007, revenue was negatively impacted by lower prices received for our products and services stemming from competitive pressures in the market.

Operating income margin declined to 34% compared to 38% in the prior fiscal year, primarily due to lower pricing, increased material and labor costs and increased depreciation expense.

*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. was supported by three price book increases between May of 2005 and May 2006. 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 as activity increases occurred without a proportional increase in headcount. Average headcount increased 12% in fiscal 2006, with revenue increasing

40%. Cost efficiencies were also 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.

***International Pressure Pumping Segment (in millions)***

| | 2007 | % Change | 2006 | % Change | 2005 |
|---|---|---|---|---|---|
| Revenue | $1,074.7 | 21% | $884.7 | 28% | $693.5 |
| Operating income | $ 152.7 | 11% | $138.1 | 78% | $ 77.5 |
| International rig count, excluding Mexico[1] | 899 | 10% | 820 | 13% | 723 |

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

*Results for fiscal 2007 compared to fiscal 2006*

| | % change in Revenue |
|---|---|
| Europe/Africa | 27% |
| Middle East | 21% |
| Asia Pacific | 28% |
| Russia | -5% |
| Latin America | 21% |

All of our operating regions within International Pressure Pumping, except Russia, showed significant increases in revenue in fiscal 2007 compared to fiscal 2006.

Europe/Africa showed improvement as the result of the acquisition of BJSP in July 2006. We have acquired a controlling interest in BJSP and now consolidate its revenue. Excluding the impact from the BJSP acquisition, revenue in the region increased 10%. Activity related revenue increases in the Netherlands and expansion of operations into Libya also contributed to the region's improvement from the prior year. These increases were slightly offset by lower coiled tubing revenue in Norway. The average active drilling rig count increased 8% compared to the prior fiscal year.

Despite a significant decline in revenue from the prior year's non-repeat blowout work in Bangladesh, the Middle East showed improved revenues due to increased activity and the introduction of vessel operations in India and increased coiled tubing work in Saudi Arabia. The average active drilling rig count for fiscal 2007 increased 13% compared to fiscal year 2006.

The award of contracts in Malaysia and activity increases in Australia accounted for most of Asia Pacific's revenue increase. This increase was offset by a decline in revenue from New Zealand due to non-repeat work in the prior fiscal year. The average active drilling rig count for fiscal 2007 increased 4% in Asia Pacific compared to fiscal year 2006.

Our Russian revenue declined as the result of the divesture of our workover rig business in the region in the second quarter of fiscal 2007 as well as lower margin performance activity. Excluding revenue from our workover rig business, revenue from the region increased 10% compared to the prior year.

Our Latin American region improvement was due primarily to increased activity in Argentina, Colombia, and Brazil. The average active drilling rig count increased 10% in Latin America compared to the prior year.

Operating income margin was 14% for fiscal 2007 compared to 16% in the prior year. Margin contributions from the Asia Pacific and Latin America were offset by margin declines from the high margin non-repeat blowout work in Bangladesh in the prior fiscal year and activity declines in Norway.

*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 also added to the overall increase in revenue in fiscal 2006 for Asia Pacific. We acquired a controlling interest in BJSP and accordingly, began consolidating its revenue effective 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.

***Canada Pressure Pumping (in millions)***

| | 2007 | % Change | 2006 | % Change | 2005 |
|---|---|---|---|---|---|
| Revenue | $386.5 | -20% | $481.4 | 38% | $348.4 |
| Operating income | $ 32.5 | -68% | $102.1 | 75% | $ 58.3 |
| Canada rig count[(1)] | 365 | -27% | 502 | 20% | 420 |

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

*Results for fiscal 2007 compared to fiscal 2006*

Lower activity levels influenced by lower natural gas prices caused revenue to decline compared to the prior year. Average active drilling rigs decreased 27% in fiscal 2007, with revenue exhibiting a corresponding decrease of 20%. The region has also experienced lower pricing for our products and services.

Operating income margin decreased to 8% from 21% in the prior year. Along with declining prices for our products and services, the region also had higher depreciation expense, material costs and labor costs during fiscal 2007.

*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.

***Oilfield Services Group (in millions)***

| | 2007 | % Change | 2006 | % Change | 2005 |
|---|---|---|---|---|---|
| Revenue | $778.4 | 20% | $648.0 | 25% | $517.7 |
| Operating income | 163.5 | 23% | 132.4 | 96% | 67.6 |

*Results for fiscal 2007 compared to fiscal 2006*

The following table summarizes the change in revenue for fiscal 2007 compared to fiscal 2006 for each of the operating segments of the Oilfield Services Group:

| | % Change in Revenue |
|---|---|
| Tubular Services | 30% |
| Process and Pipeline Services | 21% |
| Chemical Services | 39% |
| Completion Tools | 28% |
| Completion Fluids | -5% |

All of our operating segments, except Completion Fluids, showed revenue improvement in fiscal 2007. Our Tubular Services' revenue for fiscal 2007 increased largely due to international market expansion, while our Process and Pipeline Services benefited from increased activity in our U.K. and U.S. operations as well as the acquisition of Norson in March 2007. Excluding the impact of the Norson acquisition, Process and Pipeline Services revenue increased 15%. Chemical Services revenue increased largely due to the acquisitions of Dyna-Coil's and Allis-Chalmers' capillary string businesses. Excluding these acquisitions, Chemical Services revenue increased 12%. Our Completion Tools revenue improvement was due to international growth as well as increased domestic deepwater activity, while revenue from our Completion Fluids operations declined due to the closing of low margin operations in the U.K. and Norway in the previous year.

Fiscal 2007 operating income margin for the Oilfield Services Group was 21%, an increase from 20% reported in fiscal year 2006, with Tubular Services being the largest contributor to the increase.

*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.

***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.

We expect a slight increase in fiscal 2008 revenue over fiscal 2007 revenue. Our U.S./Mexico Pressure Pumping revenue is expected to increase, but we also expect pricing pressures to continue in the U.S. market. In Canada, we expect a marginal increase in drilling activity and we expect spring break up levels to be less severe than those experienced in fiscal 2007. We will continue to focus on labor cost efficiencies as well as equipment utilization and monitoring of discretionary spending in North America.

Our International Pressure Pumping revenue is expected to increase in fiscal 2008. We have developed a number of strategies to address low-performing countries and we expect margin expansion in this segment throughout fiscal 2008.

Revenue from our Oilfield Services Group is expected to increase in fiscal 2008, as the divisions within this segment continue to expand into the international markets through our existing pressure pumping infrastructure.

***Other Expenses***

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

| | 2007 | % of Revenue | 2006 | % of Revenue | 2005 | % of Revenue |
|---|---|---|---|---|---|---|
| Research and engineering | $ 67.5 | 1.4% | $ 63.9 | 1.5% | $ 54.2 | 1.7% |
| Marketing expense | 107.4 | 2.2% | 103.3 | 2.4% | 92.3 | 2.8% |
| General and administrative expense | 144.0 | 3.0% | 132.0 | 3.0% | 111.3 | 3.4% |

*Research and engineering expense:* While these expenses have decreased as a percent of revenue, the total of these expenses increased 6% for fiscal 2007 when compared to fiscal 2006. The increase mostly relates to increased personnel at our primary research facility in Tomball, Texas and certain operating locations to support higher activity.

The total of these expenses increased 18% 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.

*Marketing expense:* These expenses increased 4% for fiscal 2007 when compared to fiscal 2006 as the result of higher commissions in certain markets internationally as well as increased headcount to support market growth.

These expenses increased 12% for fiscal 2006, compared to fiscal 2005. The increase was largely due to higher activity levels experienced throughout our business in fiscal 2006.

*General and administrative expense*: While these expenses have remained consistent as a percent of revenue, they increased 9% for fiscal 2007 compared to fiscal 2006. The increase primarily relates to increased personnel and a stock based compensation expense increase of $7.6 million, offset by lower compensation expense related to annual performance incentive accruals. The decrease in annual performance incentive accruals is the primary reason for the decrease in Corporate expenses in fiscal 2007.

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).

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

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Interest expense | $(32.7) | $(14.6) | $(11.0) |
| Interest income | 1.6 | 14.9 | 11.3 |
| Other income (expense), net | (6.6) | — | 16.0 |

*Interest Expense and Interest Income:* Interest expense, net of capitalized interest, increased $18.1 million for fiscal 2007 compared to fiscal 2006 as the result of higher average outstanding debt during the respective periods. As a result of an increased average debt balance in addition to higher manufacturing levels, capitalized interest increased $6.0 million for fiscal 2007 compared to fiscal 2006.

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.

Interest income decreased $13.3 million for fiscal 2007 compared fiscal 2006 as a result of a lower average cash and cash equivalents balance throughout the fiscal year.

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

*Other Income (Expense), net:* The increase in other expense, net for fiscal 2007 consisted primarily of minority interest expense, due to the acquisition of controlling interest in BJSP during the third quarter of fiscal 2006.

In fiscal 2006, we received $2.8 million for the recovery of misappropriated funds, 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 additional information, 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):

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Cash flow from operations | $ 840.7 | $ 832.5 | $ 545.7 |
| Cash flow used in investing | (777.9) | (503.2) | (86.2) |
| Cash flow used in financing | (98.0) | (593.4) | (527.8) |
| Effect of exchange rate changes on cash | 1.0 | — | — |
| Change in cash and cash equivalents | $ (34.2) | $(264.1) | $ (68.2) |

*Fiscal 2007*

As a result of pricing pressures in North America during fiscal 2007, we experienced only a modest increase in cash flow from operations compared to fiscal 2006. Significant uses of cash included increased inventory in anticipation of increases in activity, increased accounts receivable as a result of increased revenue and days sales outstanding, and increased prepaid expenses primarily related to tax payments. Increased accounts payable also contributed to cash flow from operations, mostly from increased activity levels.

The cash flow used in investing during fiscal 2007 was almost entirely due to $752.1 million of purchases of property, plant, and equipment, including $47.8 million paid to buy-out an equipment partnership established in 1997. We also paid $57.9 million, net of cash, for acquisitions.

Cash flows used in financing consisted of $11.0 million, net, in proceeds from short term borrowings, $74.6 million in repurchases of our common stock and $58.6 million of dividend payments during fiscal 2007. We also received proceeds in the amount of $22.4 million from employee stock purchases and stock option exercises during fiscal 2007.

*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 was 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 also paid $52.2 million in connection with 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 thereby reducing cash and cash equivalents and current debt.

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.

*Liquidity and Capital Resources*

Cash flows from operations are expected to be our primary source of liquidity in fiscal 2008. Our sources of liquidity also include cash and cash equivalents of $58.2 million at September 30, 2007 and the available financing facilities listed below (in millions):

| Financing Facility | Expiration | Borrowings at September 30, 2007 | Available at September 30, 2007 |
|---|---|---|---|
| Revolving Credit Facility | August 2012 | $147.0 | $253.0 |
| Discretionary | Various times within the next 12 months | $ 24.3 | $140.6 |

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, 2007, we had $250.0 million of the Senior Notes due 2008 issued and outstanding and $249.8 million, net of discount, of the 5.75% Senior Notes due 2011 issued and outstanding.

In August 2007, we amended and restated our then existing revolving credit facility. The amended and restated revolving credit facility (the "Revolving Credit Facility") 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 August 2012. In addition, we have the right to request up to an additional $200 million over the permitted borrowings of $400 million, subject to the approval of our lenders at the time of the request. 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 $0.3 million in fiscal 2007 and $0.5 million in fiscal 2006. 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 62.5%, though there were no material fees in fiscal 2007 or 2006. At September 30, 2007 and 2006, there was $147.0 million and $160.0 million, respectively, in outstanding borrowings under the Revolving Credit Facility.

In addition to the Revolving Credit Facility, we had $164.9 million of unsecured, discretionary lines of credit at September 30, 2007, 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 $24.3 million and $0.3 million in outstanding borrowings under these lines of credit at September 30, 2007 and 2006, respectively. The weighted average interest rates on short-term borrowings outstanding as of September 30, 2007 and 2006 were 5.40% and 5.95%, 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.

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 all covenants imposed.

*Cash Requirements*

We anticipate capital expenditures to be approximately $640 million in fiscal 2008, compared to $704.3 million in fiscal 2007, excluding $47.8 million for the purchase of assets from an equipment partnership. The 2008 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. 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 since expanded the U.S. fleet recapitalization initiative to include additional equipment, such as cementing, nitrogen and acidizing equipment and have made significant progress in adding new equipment. However, much of the older equipment still remains in operation due to the increases in market activity. We plan to continue adding new equipment to our fleet and the market activity level at the time the equipment is ready for use will determine if the new equipment will be used for expansion or used as replacement assets. At the end of fiscal 2007, approximately 20% of our U.S. fleet remained candidates for future replacement as part of our recapitalization initiative. The actual amount of fiscal 2008 capital expenditures will depend primarily on maintenance requirements and expansion opportunities and our ability to execute our budgeted capital expenditures.

In fiscal 2008, our minimum pension and postretirement funding requirements are anticipated to be approximately $19.0 million. We contributed $16.8 million during fiscal 2007.

We paid cash dividends in the amount of $.05 per common share on a quarterly basis in fiscal 2007, totaling $58.6 million. We anticipate paying a quarterly dividend in fiscal 2008; 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, 2007, we had $250.0 million of Senior Notes due 2008 issued and outstanding and $249.8 million of 5.75% Senior Notes due 2011 issued and outstanding, net of discount (collectively "the Notes"). We intend to redeem the $250.0 million Senior Notes due 2008 with existing cash and if necessary, through funds available from our Revolving Credit Facility. We expect cash paid for net interest expense (net of interest income) to be approximately $26.3 million in fiscal 2008.

The following table summarizes our contractual obligations and other commercial commitments as of September 30, 2007 (in thousands):

| Contractual Obligations | Total | Less than 1 year | 1-3 Years | 4-5 Years | After 5 Years |
|---|---|---|---|---|---|
| Long term and short term debt | $ 671,268 | $ 421,268 | $250,000 | $ — | $ — |
| Interest on long term debt and capital leases | 69,423 | 26,296 | 28,752 | 14,375 | — |
| Capital lease obligations | 2,949 | 867 | 1,146 | 936 | — |
| Operating leases | 174,956 | 46,703 | 73,716 | 51,634 | 2,904 |
| Equipment financing arrangement[(1)] | 54,649 | 12,990 | 41,659 | — | — |
| Purchase obligations[(2)] | 392,576 | 388,576 | 4,000 | — | — |
| Purchase commitments[(3)] | 101,822 | 26,317 | 41,032 | 30,643 | 3,830 |
| Other long-term liabilities[(4)] | 91,449 | 90,777 | 144 | 96 | 432 |
| Total contractual cash obligations | $1,554,092 | $1,013,794 | $440,449 | $97,684 | $7,166 |

(1) As discussed below, we have the option, but not the obligation, to purchase the pumping service equipment in this partnership for approximately $32 million in 2010. 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 "*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, in which we own a 1% interest. 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 $9.0 million and $16.1 million as of September 30, 2007 and September 30, 2006, 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 $0.8 million in fiscal 2007 and $2.8 million in fiscal 2006. 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.

The option price to purchase the equipment under the partnership depends in part on the fair market value of the equipment held by the partnership at the time the option is exercised as well as other factors specified in the agreement.

In 1997, we contributed certain pumping service equipment to a limited partnership, in which we owned a 1% interest. The equipment was used to provide services to our customers for which we paid a service fee. On February 9, 2007, we purchased the remaining partnership interest for $47.8 million, and as a result acquired the partnership equipment. The acquisition of the partnership controlling interest was accounted for as an asset purchase.

**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, 2007 (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 | $ 53,346 | $ 53,336 | $ 10 | $ — | $ — |
| Guarantees | 193,392 | 81,567 | 65,595 | 15,658 | 30,572 |
| Total Other Commercial Commitments | $246,738 | $134,903 | $65,605 | $15,658 | $30,572 |

## Investigations Regarding Misappropriation and Possible Illegal Payments

We are in discussions with the DOJ and SEC regarding our internal investigation and certain other matters described in Note 12 of the Notes to the Consolidated Financial Statements. 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.

## 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 reporting unit goodwill with the carrying amount of that goodwill. If the carrying amount of reporting unit goodwill exceeds the implied fair value of that goodwill, 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, and rig count.

No impairment adjustment was necessary to our $963.9 million goodwill balance at September 30, 2007. See Note 11 of the Notes to the Consolidated Financial Statements for more information on goodwill.

*Pension and Postretirement Benefit Plans:* Pension expense is determined in accordance with the provisions of SFAS 87, *Employers' Accounting for Pensions* and SFAS 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions.* 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 accordance with SFAS 158, 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 recognized as a component of other comprehensive income. Amounts recorded to other comprehensive income are amortized and recognized in net periodic pension expense in future periods.

In fiscal 2008, we will have a pension and postretirement funding requirement of $19.0 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 is being 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 2008, we will expense approximately $23.3 million in connection with the settlement. This consists of $7 million of prepaid pension cost and $16 million of loss currently recognized in other comprehensive income. 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.

*Income Taxes:* The effective income tax rates were 32.3%, 31.4%, and 30.7% for the years ended September 30, 2007, 2006, and 2005, 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 February 2007, the FASB issued SFAS No. 159 ("SFAS 159"), The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statement No. 115. This Statement provides companies with an option to report selected financial assets and liabilities at fair value. Under SFAS 159, companies that elect the fair value option will report unrealized gains and losses in earnings at each subsequent reporting date. In addition, SFAS 159 establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. The fair value option election is irrevocable, unless a new election date occurs. SFAS 159 is effective the beginning of an entity's first fiscal year beginning after November 15, 2007 and is to be applied prospectively, unless the entity elects early adoption. We are currently in the process of evaluating the impact of SFAS 159 on our financial statements, if we choose to elect this option.

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. In addition, FIN 48 requires us to disclose the classification of interest and penalties related to uncertain tax positions. We record these as a component of income tax expense. We estimate the impact of adopting FIN 48 to be a reduction in retained earnings in the range of $6 million to $10 million.

**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, 2007, our combined interest expense to third parties would increase by a total of $197 thousand each month in which such increase continued. At September 30, 2007 and 2006, we had fixed-rate debt outstanding of $249.8 million and $249.7 million, net of discount, respectively. 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 $4.5 million if interest rates were to decline by 10% from their rates at September 30, 2007.

Periodically, we borrow funds which are denominated in foreign currencies, which exposes us to market risk associated with exchange rate movements. There were $15.4 million and $0.3 million borrowings denominated in foreign currencies at September 30, 2007 and 2006, respectively. 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, 2007. The expected maturity dates and fair value of our market risk sensitive instruments are stated below (in millions). All items described are non-trading and are stated in U.S. dollars.

| | Expected Maturity Dates | | | | | | | Fair Value |
|---|---|---|---|---|---|---|---|---|
| | 2008 | 2009 | 2010 | 2011 | 2012 | Thereafter | Total | 9/30/07 |
| **SHORT-TERM BORROWINGS** | | | | | | | | |
| Bank borrowings; U.S. $ denominated—average rate 5.40% | $ 24.3 | | | | | | $ 24.3 | $ 24.3 |
| Revolving Credit Facility—Average rate 5.44% | 147.0 | | | | | | 147.0 | 147.0 |
| **LONG-TERM BORROWINGS** | | | | | | | | |
| Floating rate Senior Notes due 2008—Average rate 5.75% | 250.0 | | | | | | 250.0 | 248.1 |
| 5.75% Senior Notes due 2011 | | | | 249.8 | | | 249.8 | 253.9 |
| **Total** | **$421.3** | **$—** | **$—** | **$249.8** | **$—** | **$—** | **$671.1** | **$673.3** |

## 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, 2007 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, 2007.

The effectiveness of our internal control over financial reporting as of September 30, 2007 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein.

| /s/ J.W. STEWART | /s/ JEFFREY E. SMITH |
|---|---|
| **J.W. Stewart** | **Jeffrey E. Smith** |
| **President and Chief Executive Officer** | **Senior 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 the internal control over financial reporting of BJ Services Company and subsidiaries (the "Company") as of September 30, 2007, 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, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

A company's internal control over financial reporting is a process designed 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, the Company maintained, in all material respects, effective internal control over financial reporting as of September 30, 2007, 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, 2007 of the Company and our report dated November 29, 2007 expressed an unqualified opinion on those consolidated financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
November 29, 2007

## 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, 2007 and 2006, 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, 2007. 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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2007, 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 Company's internal control over financial reporting as of September 30, 2007, 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 November 29, 2007 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
November 29, 2007

## BJ SERVICES COMPANY

## CONSOLIDATED STATEMENT OF OPERATIONS

| | Year Ended September 30, | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | (in thousands, except per share amounts) | | |
| Revenue | $4,802,409 | $4,367,864 | $3,243,186 |
| Operating expenses: | | | |
| Cost of sales and services | 3,332,620 | 2,895,749 | 2,334,198 |
| Research and engineering | 67,536 | 63,875 | 54,197 |
| Marketing | 107,421 | 103,319 | 92,255 |
| General and administrative | 143,992 | 132,011 | 111,285 |
| Loss on long-lived assets | 301 | 1,174 | 14,192 |
| Total operating expenses | 3,651,870 | 3,196,128 | 2,606,127 |
| Operating income | 1,150,539 | 1,171,736 | 637,059 |
| Interest expense | (32,731) | (14,558) | (10,951) |
| Interest income | 1,624 | 14,916 | 11,281 |
| Other (expense) income, net | (6,584) | (11) | 15,958 |
| Income before income taxes | 1,112,848 | 1,172,083 | 653,347 |
| Income tax expense | 359,208 | 367,473 | 200,305 |
| Net income | $ 753,640 | $ 804,610 | $ 453,042 |
| Earnings per share: | | | |
| Basic | $ 2.57 | $ 2.55 | $ 1.40 |
| Diluted | $ 2.55 | $ 2.52 | $ 1.38 |
| Weighted average shares outstanding: | | | |
| Basic | 292,757 | 315,022 | 323,763 |
| Diluted | 295,916 | 318,820 | 329,115 |

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, 2007 | As of September 30, 2006 |
|---|---|---|
| | (in thousands) | |
| Current assets: | | |
| Cash and cash equivalents | $ 58,199 | $ 92,445 |
| Receivables, less allowance for doubtful accounts: 2007, $20,550; 2006, $18,976 | 1,022,847 | 927,027 |
| Inventories: | | |
| Products | 226,666 | 185,249 |
| Work-in-progress | 37,460 | 27,308 |
| Parts | 221,811 | 143,347 |
| Total inventories | 485,937 | 355,904 |
| Deferred income taxes | 19,994 | 5,103 |
| Prepaid expenses | 72,033 | 36,311 |
| Other current assets | 44,762 | 42,070 |
| Total current assets | 1,703,772 | 1,458,860 |
| Property: | | |
| Land | 29,180 | 26,573 |
| Buildings and other | 359,735 | 317,337 |
| Machinery and equipment | 2,947,473 | 2,232,240 |
| Total property | 3,336,388 | 2,576,150 |
| Less accumulated depreciation | 1,370,669 | 1,183,224 |
| Property, net | 1,965,719 | 1,392,926 |
| Goodwill | 963,937 | 928,297 |
| Deferred income taxes | 30,471 | 29,557 |
| Investments and other assets | 51,313 | 52,648 |
| Total assets | $4,715,212 | $3,862,288 |

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

**BJ SERVICES COMPANY**

**LIABILITIES AND STOCKHOLDERS' EQUITY**

| | As of September 30, 2007 | As of September 30, 2006 |
|---|---|---|
| | (in thousands, except shares) | |
| Current liabilities: | | |
| Accounts payable, trade | $ 530,029 | $ 435,040 |
| Short-term borrowings | 171,268 | 160,274 |
| Current portion of long-term debt | 250,000 | — |
| Accrued employee compensation and benefits | 124,231 | 131,725 |
| Income taxes | 51,829 | 60,160 |
| Taxes other than income | 37,282 | 25,385 |
| Accrued insurance | 26,284 | 21,965 |
| Other accrued liabilities | 122,265 | 113,387 |
| Total current liabilities | 1,313,188 | 947,936 |
| Long-term debt | 249,760 | 499,694 |
| Deferred income taxes | 95,485 | 66,584 |
| Accrued postretirement benefits | 57,504 | 54,296 |
| Other long-term liabilities | 147,877 | 146,838 |
| Commitments and contingencies (Note 10) | | |
| Stockholders' equity: | | |
| Preferred stock (authorized 5,000,000 shares, none issued) | | |
| Common stock, $.10 par value (authorized 910,000,000 shares; 347,510,648 shares issued and 291,735,636 outstanding in 2007; 347,510,648 shares issued and 293,193,764 outstanding in 2006) | 34,752 | 34,752 |
| Capital in excess of par | 1,060,115 | 1,028,813 |
| Retained earnings | 3,183,922 | 2,494,350 |
| Accumulated other comprehensive income | 51,644 | 22,833 |
| Treasury stock, at cost (2007 – 55,775,012 shares; 2006 – 54,316,884 shares) | (1,479,035) | (1,433,808) |
| Total stockholders' equity | 2,851,398 | 2,146,940 |
| Total liabilities and stockholders' equity | $ 4,715,212 | $ 3,862,288 |

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, 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** |
| Comprehensive income: | | | | | | | | |
| Net income | | | | | | 753,640 | | |
| Other comprehensive income, net of tax: | | | | | | | | |
| Cumulative translation adjustments | | | | | | | 40,551 | |
| Minimum pension liability adjustment | | | | | | | 3,272 | |
| Comprehensive income | | | | | | | | 797,463 |
| Adoption of SFAS 158, net of tax (Note 9) | | | | | | | (15,012) | (15,012) |
| Dividends declared | | | | | | (57,362) | | (57,362) |
| Treasury stock purchase | (2,565) | | | (74,597) | | | | (74,597) |
| Reissuance of treasury stock for: | | | | | | | | — |
| Stock option plan | 528 | | | 14,019 | | (6,300) | | 7,719 |
| Stock purchase plan | 488 | | | 12,916 | | (406) | | 12,510 |
| Director stock award | 43 | | (1,127) | 1,127 | | | | — |
| Bonus stock award | 48 | | (1,308) | 1,308 | | | | — |
| Stock based compensation | | | 31,625 | | | | | 31,625 |
| Tax benefit from exercise of options | | | 2,112 | | | | | 2,112 |
| **Balance, September 30, 2007** | **291,736** | **$34,752** | **$1,060,115** | **$(1,479,035)** | **$ —** | **$3,183,922** | **$ 51,644** | **$ 2,851,398** |

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

## BJ SERVICES COMPANY

## CONSOLIDATED STATEMENT OF CASH FLOWS

| | Year Ended September 30, | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | | (in thousands) | |
| **Cash flows from operating activities:** | | | |
| Net income | $ 753,640 | $ 804,610 | $ 453,042 |
| Adjustments to reconcile net income to cash provided from operating activities: | | | |
| Depreciation | 209,019 | 166,763 | 136,861 |
| Net loss on long-lived assets | 301 | 1,174 | 14,192 |
| Excess tax benefits from stock compensation | (1,812) | (3,419) | — |
| Recognition of unearned compensation | — | — | 8,681 |
| Deferred income tax expense (benefit) | 17,472 | 6,024 | (7,111) |
| Minority interest expense | 11,315 | 3,970 | 3,725 |
| Changes in: | | | |
| Receivables | (97,355) | (215,020) | (154,677) |
| Inventories | (129,387) | (111,189) | (53,161) |
| Prepaid expenses | (35,950) | (14,712) | (453) |
| Accounts payable, trade | 99,375 | 105,833 | 81,756 |
| Employee compensation and benefits | (7,494) | 26,763 | 26,913 |
| Current income tax | (8,561) | 34,726 | (7,611) |
| Other current assets | 1,909 | (20,561) | 12,456 |
| Other current liabilities | 22,430 | 17,612 | (979) |
| Other, net | 5,755 | 29,880 | 32,071 |
| Net cash flows provided from operating activities | 840,657 | 832,454 | 545,705 |
| **Cash flows from investing activities:** | | | |
| Property additions | (752,113) | (459,974) | (323,763) |
| Proceeds from disposal of assets | 32,143 | 8,932 | 7,834 |
| Proceeds of U.S. Treasury securities | — | — | 229,774 |
| Acquisitions of businesses, net of cash acquired | (57,920) | (52,172) | — |
| Net cash used for investing activities | (777,890) | (503,214) | (86,155) |
| **Cash flows from financing activities:** | | | |
| Proceeds from exercise of stock options and stock purchase plan | 22,388 | 26,142 | 45,165 |
| Purchase treasury stock | (74,597) | (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 | 10,994 | 156,884 | (364) |
| Dividends paid to shareholders | (58,630) | (64,338) | (51,855) |
| Excess tax benefits from stock compensation | 1,812 | 3,419 | — |
| Debt issuance costs | — | (2,824) | — |
| Net cash flows used in financing activities | (98,033) | (593,357) | (527,783) |
| Effect of exchange rate changes on cash | 1,020 | 54 | 16 |
| Decrease in cash and cash equivalents | (34,246) | (264,063) | (68,217) |
| Cash and cash equivalents at beginning of year | 92,445 | 356,508 | 424,725 |
| Cash and cash equivalents at end of year | $ 58,199 | $ 92,445 | $ 356,508 |

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

## 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 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 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.

Certain amounts for 2006 and 2005 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 receivables. 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 $8.0 million, $2.0 million, and $1.2 million for the years ended September 30, 2007, 2006 and 2005, 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. Worldwide average active drilling rigs has experienced continued 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 and was maintained by Corporate personnel in our idle asset yard 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. We recorded an $11.7 million impairment during our fourth fiscal quarter of 2005 related to idle assets. This impairment is reflected in loss on long-lived assets in the Consolidated Statement of Operations and within Corporate in our segment footnote disclosure.

*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 by reporting unit for possible impairment on an annual basis, or if circumstances indicate that impairment may exist. In determining our reporting units we considered the way we manage our operations and the nature of those operations. Our reporting units are our operating segments (see Note 8). 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, 2007 and 2006, 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 14.8 years. We utilize undiscounted estimated cash flows to evaluate any possible impairment of intangible assets. 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 in other comprehensive income. Our operations 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. No such contracts were outstanding as of September 30, 2007 or 2006.

*Employee stock-based compensation:* 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 which is determined using the Black-Scholes option-pricing model for the stock option awards, bonus stock and phantom stock and a Monte-Carlo simulation model for the stock incentive awards. Awards granted are expensed ratably over the vesting period of the award, unless retirement age is reached in which case the expense is accelerated. We reduce the expense recognized based on an estimated forfeiture rate at the time of grant and revise this rate, if necessary, in subsequent periods to reflect actual forfeitures. Excess tax benefits, as defined by SFAS 123(R), are recognized as an addition to capital in excess of par.

*New accounting pronouncements:* In February 2007, the FASB issued SFAS No. 159 ("SFAS 159"), The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statement No. 115. This Statement provides companies with an option to report selected financial assets and liabilities at fair value. Under SFAS 159, companies that elect the fair value option will report unrealized gains and losses in earnings at each subsequent reporting date. In addition, SFAS 159 establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. The fair value option election is irrevocable, unless a new election date occurs. SFAS 159 is effective the beginning of an entity's first fiscal year beginning after November 15, 2007 and is to be applied prospectively, unless the entity elects early adoption. We are currently in the process of evaluating the impact of SFAS 159 on our financial statements, if we choose to elect this option.

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. In addition, FIN 48 requires us to disclose the classification of interest and penalties related to uncertain tax positions. We record these as a component of income tax expense. We estimate the impact of adopting FIN 48 to be a reduction in retained earnings in the range of $6 million to $10 million.

### 3. Acquisitions of Businesses

*Fiscal 2007*

On November 3, 2006, we completed the acquisition of Profile International Ltd. ("Profile") for a total purchase price of $2.5 million, which resulted in $2.2 million of goodwill. Profile, located in Newcastle, England, provides caliper inspection tools for pipeline integrity assessment to markets worldwide. This business complements our pipeline inspection business in the Oilfield Services Group segment.

On December 20, 2006, we purchased substantially all of the operating assets of Tekcor Technology, Ltd. ("Tekcor") for $8.3 million, which resulted in an increase of $3.6 million to total current assets, $0.7 million in property and equipment and $4.0 million to technology based intangible assets. Tekcor provides specialty chemicals and related services to the oil and gas well drilling industry. Located in Houston, Texas, Tekcor services markets along the Texas and Louisiana Gulf Coast and is included in our completion fluids business in the Oilfield Services Group segment.

On March 1, 2007 we acquired Aberdeen-based Norson Services Ltd, ("Norson"), a division of Norson Group Ltd., and substantially all of the assets of Norson Group's United States subsidiary Norson Services LLC. The total purchase price paid for both acquisitions was $29.0 million, including legal fees, which resulted in an increase of $7.4 million in total current assets, $5.9 million in property and equipment, $1.8 million in intangible assets, $5.4 million in current liabilities, and $19.3 million of goodwill. The acquisition strengthens our service capabilities with the addition of Norson's hydraulic and electrical umbilical testing services and the services provided by the Norson's subsea units, which include remote pigging and flooding, subsea hydro testing and subsea data logging. This business complements our process and pipeline business in the Oilfield Services Group segment.

On June 30, 2007, we completed the acquisition of substantially all of the capillary tubing assets of Allis-Chalmers for a total purchase price of $16.3 million, which resulted in an increase of $1.5 million in current assets, $1.8 million in property and equipment, and $13.0 million of goodwill. The assets are used for the installation and service of capillary injection systems primarily in the U.S. and Mexico. The assets complement our Dyna-Coil acquisition which occurred in the fourth quarter of fiscal 2006 and will enhance our chemical services operation in the Oilfield Services Group segment.

*Fiscal 2006*

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, fracturing 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 was accounted for as a step-acquisition, we have control of BJSP and 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*, in 2006, we 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. 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.

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 chemical services business in the Oilfield Services Group 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 currently in the process of completing our review and determination of the fair values of the assets acquired from Norson and Allis-Chalmers. Accordingly, allocation of the purchase price is subject to revision based on final determination of the asset values. Pro forma financial information for our fiscal 2007 and fiscal 2006 acquisitions is not included as they were not material individually or in aggregate to our 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, 2007 (in thousands, except per share amounts):

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Net Income | $753,640 | $804,610 | $453,042 |
| Weighted-average common shares outstanding | 292,757 | 315,022 | 323,763 |
| Basic earnings per share | $ 2.57 | $ 2.55 | $ 1.40 |
| Weighted-average common and dilutive potential common shares outstanding: | | | |
| Weighted-average common shares outstanding | 292,757 | 315,022 | 323,763 |
| Assumed exercise of stock options[(1)] | 3,159 | 3,798 | 5,352 |
| Weighted-average dilutive shares outstanding | 295,916 | 318,820 | 329,115 |
| Diluted earnings per share | $ 2.55 | $ 2.52 | $ 1.38 |

(1) For the year ended September 30, 2007, 2.9 million stock options were excluded from the computation of diluted earnings per share due to their antidilutive effect. There were no stock options excluded from the computation of diluted earnings per share due to their antidilutive effect for the years ended September 30, 2006 and 2005.

## 5. Debt

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

| | 2007 | 2006 |
|---|---|---|
| Floating rate Senior Notes due 2008 | $250,000 | $250,000 |
| 5.75% Senior Notes due 2011, net of discount | 249,760 | 249,694 |
| | 499,760 | 499,694 |
| Less current maturities of long-term debt | 250,000 | — |
| Long term debt | $249,760 | $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, 2007, we had $250.0 million of the Senior Notes due 2008 issued and outstanding and $249.8 million, net of discount, of the 5.75% Senior Notes due 2011 issued and outstanding. We intend to redeem the $250.0 million Senior Notes due 2008 with existing cash and if necessary, through funds available from our Revolving Credit Facility.

In August 2007, we amended and restated our then existing revolving credit facility. The amended and restated revolving credit facility (the "Revolving Credit Facility") 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 August 2012. In addition, we have the right to request up to an additional $200 million over the permitted borrowings of $400 million, subject to the approval of our lenders at the time of the request. 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 $0.3 million in fiscal 2007 and $0.5 million in fiscal 2006. 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 62.5%, though there were no material fees in fiscal 2007 or 2006. At September 30, 2007 and 2006, there was $147.0 million and $160.0 million, respectively, in outstanding borrowings under the Revolving Credit Facility.

In addition to the Revolving Credit Facility, we had $164.9 million of unsecured, discretionary lines of credit at September 30, 2007, 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 $24.3 million and $0.3 million in outstanding borrowings under these lines of credit at September 30, 2007 and 2006, respectively. The weighted average interest rates on short-term borrowings outstanding as of September 30, 2007 and 2006 were 5.40% and 5.95%, 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.

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 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 Currency Debt:* Periodically, we borrow funds which are denominated in foreign currencies, which exposes us to market risk associated with exchange rate movements. There were $15.4 million borrowings denominated in foreign currencies at September 30, 2007 and $0.3 million borrowings at September 30, 2006.

The fair value of financial instruments that differed from their carrying value at September 30, 2007 and 2006 was as follows (in thousands):

| | 2007 | | 2006 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Floating rate Senior Notes due 2008 | $250,000 | $248,120 | $250,000 | $249,990 |
| 5.75% Senior Notes due 2011 | 249,760 | 253,900 | 249,694 | 253,543 |

## 7. Income Taxes

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

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| United States | $ 831,852 | $ 848,586 | $425,399 |
| Foreign | 280,996 | 323,497 | 227,948 |
| Income before income taxes | $1,112,848 | $1,172,083 | $653,347 |

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

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Current: | | | |
| United States—Federal | $260,374 | $267,287 | $125,209 |
| United States—State | 21,680 | 14,292 | 4,879 |
| Foreign | 59,682 | 79,870 | 77,328 |
| Total current | 341,736 | 361,449 | 207,416 |
| Deferred: | | | |
| United States—Federal | 5,069 | 7,363 | 8,696 |
| United States—State | 1,258 | 900 | 891 |
| Foreign | 11,145 | (2,239) | (16,698) |
| Total deferred | 17,472 | 6,024 | (7,111) |
| Income tax expense | $359,208 | $367,473 | $200,305 |

The consolidated effective income tax rates (as a percent of income (loss) before income taxes) for the three years ended September 30, 2007 varied from the United States statutory income tax rate for the reasons set forth below:

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Statutory rate | 35.0% | 35.0% | 35.0% |
| Foreign earnings at varying rates | (2.9) | (2.9) | (3.6) |
| State income taxes, net of federal benefit | 1.3 | 0.8 | 0.6 |
| Other income taxes | 1.0 | 0.7 | 1.1 |
| Changes in valuation allowance | (0.8) | 0.3 | 0.5 |
| Foreign income recognized domestically | — | 6.9 | 9.7 |
| Foreign expense recognized domestically | — | (1.4) | — |
| Dividends received deduction | — | (1.7) | — |
| Domestic production activity | (0.7) | (0.7) | — |
| Tax credits | (1.0) | (5.9) | (12.3) |
| Nondeductible expenses | 1.0 | 0.8 | 0.5 |
| Other, net | (0.6) | (0.5) | (0.8) |
| | 32.3% | 31.4% | 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 purposes. Deferred tax assets and liabilities as of September 30 were as follows (in thousands):

| | 2007 | 2006 |
|---|---|---|
| Assets: | | |
| Accrued compensation expense | $ 24,309 | $ 11,333 |
| Accrued postretirement benefits | 21,356 | 19,882 |
| Pension liability | 17,254 | 14,042 |
| Deferred gain[1] | 5,029 | 6,467 |
| Accrued insurance expense | 9,307 | 7,790 |
| Other accrued expenses | 24,651 | 28,737 |
| Foreign tax credit carryforwards | 21,375 | 37,211 |
| Net operating and capital loss carryforwards | 28,842 | 18,934 |
| Valuation allowance | (32,012) | (45,013) |
| Total deferred tax asset | $ 120,111 | $ 99,383 |
| Liabilities | | |
| Differences in depreciable basis of property | $(144,407) | $(111,992) |
| Unrealized gain/loss | (10,387) | (8,771) |
| Pension asset | (2,639) | (8,526) |
| Earnings of foreign affiliates | (2,345) | (2,345) |
| Income accrued for financial reporting purposes, not yet reported for tax | (5,583) | — |
| Total deferred tax liability | (165,361) | (131,634) |
| Net deferred tax liability | $ (45,250) | $ (32,251) |

(1) Deferred gain on the contribution of pumping service equipment to the partnership referred to in Note 10.

At September 30, 2007, we had approximately $96.6 million of foreign net operating loss carryforwards and $2.4 million of state net operating loss carryforwards. The foreign net operating loss carryforwards expire as follows: $7.6 million by fiscal year 2016 and the remaining $89.0 million does not expire. The state net operating losses will expire between fiscal year 2008 and fiscal year 2018. We also had $21.4 million of U.S. foreign tax credit carryforwards, substantially all which 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, 2007.

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 $379.6 million as of September 30, 2007. 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 $32.7 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.

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. 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. These 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. 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 chemical services, casing and tubular services, process and pipeline services, completion tools and completion fluids services in the U.S. and in select markets internationally. These 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, 2007, 2006, and 2005 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, 2007, 2006 and 2005, 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 |
|---|---|---|---|---|---|---|
| **2007** | | | | | | |
| Revenue | $2,562,747 | $1,074,744 | $386,547 | $778,371 | $ — | $4,802,409 |
| Operating income (loss) | 881,631 | 152,734 | 32,493 | 163,539 | (79,858) | 1,150,539 |
| Total assets | 1,504,397 | 1,339,312 | 550,449 | 980,846 | 340,208 | 4,715,212 |
| Capital expenditures | 289,278 | 210,684 | 83,643 | 82,796 | 85,712 | 752,113 |
| Depreciation | 89,718 | 55,111 | 29,327 | 27,804 | 7,059 | 209,019 |
| **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 |

### Geographic Information

| | Revenue | Long-Lived Assets |
|---|---|---|
| **2007** | | |
| United States | $2,867,442 | $2,069,306 |
| Canada | 432,392 | 336,434 |
| Other countries | 1,502,575 | 575,229 |
| Consolidated total | $4,802,409 | $2,980,969 |
| **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 |

### Revenue by Product Line

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Cementing | $1,231,643 | $1,090,787 | $ 822,447 |
| Stimulation | 2,721,638 | 2,560,063 | 1,835,560 |
| Other | 849,128 | 717,014 | 585,179 |
| Total revenue | $4,802,409 | $4,367,864 | $3,243,186 |

A reconciliation from the segment information to consolidated income before income taxes for each of the three years ended September 30, 2007 is set forth below (in thousands):

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Total operating income for reportable segments | $1,150,539 | $1,171,736 | $637,059 |
| Interest expense | (32,731) | (14,558) | (10,951) |
| Interest income | 1,624 | 14,916 | 11,281 |
| Other (expense) income, net | (6,584) | (11) | 15,958 |
| Income before income taxes | $1,112,848 | $1,172,083 | $653,347 |

## 9. Employee Benefit Plans

### Adoption of SFAS 158

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"), which requires companies to recognize the over funded or under funded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in our 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. We adopted all of the requirements of SFAS 158 for the fiscal year ended September 30, 2007. We had previously measured our defined benefit plan assets and obligations as of our fiscal year-end. Thus, this portion of SFAS 158 did not impact our financial statements. The impact of adopting the remaining requirements of SFAS 158 on our statement of financial position as of September 30, 2007 is shown below:

| | Before Application of SFAS 158 | U.S. Pensions | Non-U.S. Pensions | Other Postretirement Benefits | After Application of SFAS 158 |
|---|---|---|---|---|---|
| Other current assets | $ 63,414 | $(16,040) | (2,612) | — | $ 44,762 |
| Current deferred income taxes | 14,037 | 5,957 | — | — | 19,994 |
| Deferred income taxes | 27,676 | — | 2,795 | — | 30,471 |
| Total assets | 4,725,112 | (10,083) | 183 | — | 4,715,212 |
| Deferred income taxes | 94,282 | — | (90) | 1,293 | 95,485 |
| Accrued postretirement benefits | 60,984 | — | | (3,480) | 57,504 |
| Other long-term liabilities | 140,487 | — | 7,390 | — | 147,877 |
| Accumulated other comprehensive income | 66,657 | (10,083) | (7,117) | 2,187 | 51,644 |
| Total stockholders' equity | 2,866,411 | (10,083) | (7,117) | 2,187 | 2,851,398 |
| Total liabilities and stockholders' equity | 4,725,112 | (10,083) | 183 | — | 4,715,212 |

## 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 is being 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 2008, we will expense approximately $23.3 million in connection with the settlement. This consists of $7 million of prepaid pension cost and $16 million of loss currently recognized in other comprehensive income. 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.

*Obligations and Funded Status*

| | U.S. | | Non-U.S. | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| **Change in benefit obligation** | | | | |
| Benefit obligation, beginning of year | $65,090 | $64,490 | $190,113 | $152,646 |
| Service cost | — | — | 5,646 | 5,212 |
| Interest cost | 3,905 | 3,582 | 10,682 | 8,768 |
| Actuarial (gain)/loss | — | 689 | (4,991) | 15,659 |
| Benefits paid from plan assets | (3,584) | (3,671) | (4,986) | (2,991) |
| Contributions by plan participants | — | — | 2,143 | 2,085 |
| Curtailments | — | — | (618) | (83) |
| Foreign currency exchange rate change | — | — | 20,684 | 8,817 |
| Defined benefit plan obligation, end of year | $65,411 | $65,090 | $218,673 | $190,113 |
| **Change in plan assets** | | | | |
| Fair value of plan assets, beginning of year | $72,196 | $69,082 | $129,127 | $107,219 |
| Actual return on plan assets | 3,905 | 5,320 | 8,295 | 9,249 |
| Contributions by employer | — | 1,465 | 15,397 | 7,463 |
| Contributions by plan participants | — | — | 2,143 | 2,085 |
| Benefits paid from plan assets | (3,584) | (3,671) | (4,986) | (2,991) |
| Settlements | — | — | (81) | — |
| Foreign currency exchange rate change | — | — | 14,992 | 6,102 |
| Fair value of plan assets, end of year | $72,517 | $72,196 | $164,887 | $129,127 |
| Over (under) funded status | $ 7,106 | $ 7,106 | $ (53,786) | $ (60,986) |
| Unrecognized net actuarial loss | N/A | 16,040 | N/A | 56,369 |
| Unrecognized prior service cost | N/A | — | N/A | — |
| Unrecognized transitional loss | N/A | — | N/A | 2,723 |
| Prepaid (accrued) net amount recognized | $ 7,106 | $23,146 | $ (53,786) | $ (1,894) |

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

| | U.S. | | Non-U.S. | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| Current asset | $7,106 | $23,146 | $ — | $ 3,409 |
| Current liability | — | — | (639) | — |
| Non-current liability | — | — | (53,147) | (52,200) |
| Accumulated other comprehensive income | N/A | N/A | N/A | 46,897 |
| Net amount recognized | $7,106 | $23,146 | $(53,786) | $ (1,894) |

The amounts recognized in accumulated other comprehensive income consist of the following as of September 30, 2007:

| | U.S. | Non-U.S. |
|---|---|---|
| Net loss (gain) | $16,040 | $54,056 |
| Net transition obligation | — | 264 |
| Total | $16,040 | $54,320 |

The estimated amortization of amounts reflected in accumulated other comprehensive income into the net periodic benefit cost is expected to be $10.0 million (net of tax) in fiscal 2008 for the U.S. plan, and is not expected to be material for the plans outside the U.S.

*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 $268.1 million and $239.8 million at September 30, 2007 and 2006, respectively.

| | U.S. | | Non-U.S. | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| Projected benefit obligation | $65,411 | $65,090 | $218,673 | $190,113 |
| Accumulated benefit obligation | 65,411 | 65,090 | 202,714 | 177,128 |
| Plan assets at fair value | 72,517 | 72,196 | 164,887 | 129,127 |

*Components of Net Periodic Benefit Cost*

| | U.S. | | | Non-U.S. | | |
|---|---|---|---|---|---|---|
| | 2007 | 2006 | 2005 | 2007 | 2006 | 2005 |
| Service cost for benefits earned | $ — | $ — | $ — | $ 5,646 | $ 5,212 | $ 4,823 |
| Interest on projected benefit obligation | 3,905 | 3,582 | 3,826 | 10,682 | 8,768 | 7,609 |
| Expected return on plan assets | (3,905) | (5,732) | (5,343) | (9,696) | (8,114) | (6,898) |
| Recognized actuarial loss | — | 587 | 587 | 3,097 | 2,170 | 2,209 |
| Net amortization | — | — | — | (39) | 18 | 74 |
| Net pension cost (benefit) | $ — | $(1,563) | $ (930) | $ 9,690 | $ 8,054 | $ 7,817 |

*Assumptions*

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

| | U.S. | | | Non-U.S. | | |
|---|---|---|---|---|---|---|
| | 2007 | 2006 | 2005 | 2007 | 2006 | 2005 |
| Weighted-average discount rate | N/A | 6.0% | 5.7% | 5.0-6.0% | 5.0-5.5% | 5.0-5.5% |
| Weighted-average expected long-term rate of return on assets | N/A | 8.5% | 8.5% | 6.0-6.8% | 6.0-7.3% | 6.0-7.6% |

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

| | U.S. | | | Non-U.S. | | |
|---|---|---|---|---|---|---|
| | 2007 | 2006 | 2005 | 2007 | 2006 | 2005 |
| Weighted-average discount rate | N/A | 5.7% | 5.8% | 5.0-6.0% | 5.0-5.5% | 5.0-5.5% |
| Weighted-average expected long-term rate of return on assets | N/A | 8.5% | 8.5% | 6.0-6.8% | 6.0-7.3% | 6.0-7.6% |
| Weighted-average rate of increase in future compensation | N/A | N/A | N/A | 3.9-5.5% | 3.8-4.5% | 3.5-4.5% |

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. Assumptions relating to the U.S. plan for 2007 are not applicable due to the pending settlement discussed above.

*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 and fixed income funds 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. Our investment portfolio as of September 30, 2007 and 2006 was:

| | U.S. | | | Non-U.S. | | |
|---|---|---|---|---|---|---|
| | **Target** | **2007** | **2006** | **Target** | **2007** | **2006** |
| Equity securities | 0% | 0% | 0% | 60-75% | 63% | 62% |
| Debt securities | 0% | 0% | 0% | 25-35% | 35% | 35% |
| Other[1] | 100% | 100% | 100% | 0-5% | 2% | 3% |

(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. We contributed $15.4 million in fiscal 2007, of which $7.9 million was discretionary. We infrequently make discretionary contributions. We expect to contribute $17.4 million to the defined benefit plans in fiscal 2008, which represents the legal or contractual minimum funding requirements and expected discretionary contributions.

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

| ***Years ended September 30,*** | |
|---|---|
| 2008[1] | $ 3,055 |
| 2009 | 3,415 |
| 2010 | 3,936 |
| 2011 | 4,244 |
| 2012 | 4,806 |
| Years 2013-2017 | 38,038 |

(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 2008. 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*

| | 2007 | 2006 |
|---|---|---|
| **Change in benefit obligation** | | |
| Benefit obligation, beginning of year | $ 55,032 | $ 49,906 |
| Service cost | 3,971 | 3,467 |
| Interest cost | 3,302 | 2,870 |
| Actuarial gain | (4,139) | (751) |
| Benefits paid from plan assets | (570) | (460) |
| Defined benefit plan obligation, end of year | $ 57,596 | $ 55,032 |
| **Change in plan assets** | | |
| Fair value of plan assets, beginning of year | $ — | $ — |
| Contributions by employer | 570 | 460 |
| Benefits paid from plan assets | (570) | (460) |
| Fair value of plan assets, end of year | $ — | $ — |
| Under funded status | $(57,596) | $(55,032) |
| Unrecognized net actuarial loss | n/a | 659 |
| Accrued net amount recognized | (57,596) | $(54,373) |

The ABO was $57.6 million and $55.0 million at September 30, 2007 and 2006, respectively.

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

| | 2007 | 2006 |
|---|---|---|
| Prepaid benefit cost | $ — | $ — |
| Accrued benefit cost | (57,596) | (54,373) |
| Intangible assets | — | — |
| Net amount recognized | $(57,596) | $(54,373) |

The postretirement benefit obligation at September 30, 2007 and 2006 was determined using a discount rate of 6.4% and 6.0%, 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.

The amounts recognized in accumulated other comprehensive income consist of a net gain of $2.2 million as of September 30, 2007. In fiscal 2008, we are not expecting any amortization of the net gain from accumulated other comprehensive income into the net periodic benefit cost.

*Components of Net Periodic Benefit Cost*

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Service cost for benefits earned | $3,971 | $3,468 | $3,295 |
| Interest on projected benefit obligation | 3,302 | 2,870 | 2,634 |
| Net pension cost | $7,273 | $6,338 | $5,929 |

The postretirement benefit cost at September 30, 2007, 2006 and 2005 was determined using a discount rate of 6.00%, 5.75% and 5.75%, 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 $1.6 million to the post retirement plan in fiscal 2008, 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,* | |
|---|---|
| 2008 | $ 1,557 |
| 2009 | 2,075 |
| 2010 | 2,658 |
| 2011 | 3,275 |
| 2012 | 3,949 |
| Years 2013-2017 | 29,847 |

**Defined Contribution 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 three years of employment. Contributions to these defined contribution plans were $31.0 million, $23.9 million, and $16.6 million, in fiscal 2007, 2006 and 2005, respectively.

**Other Postretirement Plans**

We have 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 upon the later of the executive's 55$^{th}$ birthday or the date the executive completes five full years of service as an officer. The expense associated with this plan was $5.5 million, $2.9 million, and $2.1 million for the years ended September 30, 2007, 2006 and 2005, respectively. The related accrued benefit obligation was $21.9 million and $16.5 million as of September 30, 2007 and 2006, respectively.

We have 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 $0.2 million, $0.7 million and $0.5 million for the years ended September 30, 2007, 2006 and 2005, respectively. The related accrued benefit obligation was $3.1 million and $2.9 million as of September 30, 2007 and 2006, respectively.

## 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 was 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. AISLIC filed a Motion for Re-hearing with the Fifth Circuit, which was denied. The case was remanded to the District Court in June 2006 for further consideration of one exclusion contained in the AISLIC policy. The District Court recently ruled that AISLIC owes an additional $4.3 million as the insurance policy covers portions of the damages incurred in the case. To date, approximately 50% of the judgment against OSCA has already been paid by AISLIC, due to the ruling by the Fifth Circuit. 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 $5.3 million. We are fully reserved for our share of this liability.

*Asbestos Litigation*

In August 2004, certain predecessors of ours, 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 our 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 us or our predecessors as their employer. Amended lawsuits were filed by four individuals against us and the remainder of the original claims (114) were dismissed. Of these four lawsuits, three failed to name us 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 us. 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 us or our predecessors as their employer could file suit against us, 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, we are unable to estimate our potential exposure to these lawsuits. We and our predecessors in the past maintained insurance which may be available to respond to these claims. In addition to the Jones Act cases, we have been named in a small number of additional asbestos cases. The allegations in these cases vary, but generally include claims that we provided some unspecified product or service which contained or utilized asbestos or that an employee was exposed to asbestos at one of our facilities or customer job site. Some of the allegations involve claims that we are the successor to the Byron Jackson Company. To date, we have been successful in obtaining dismissals of such cases without any payment in settlements or judgments, although some remain pending at the present time. We intend to defend ourselves vigorously in all of these cases based on the information available to us at this time. We do not expect the outcome of these lawsuits, individually or collectively, to have a material adverse effect on our 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.

**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, management opted to remove the existing tanks, beginning in 1989. We 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, are currently named as a potentially responsible party at five waste disposal sites owned by third parties. An accrual of approximately \$3.4 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, in which we own a 1% interest. 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 \$9.0 million and \$16.1 million as of September 30, 2007 and September 30, 2006, 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 $0.8 million in fiscal 2007 and $2.8 million in fiscal 2006. 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. The option price to purchase the equipment under the partnership depends in part on the fair market value of the equipment held by the partnership at the time the option is exercised as well as other factors specified in the agreement.

In 1997, we contributed certain pumping service equipment to a limited partnership, in which we owned a 1% interest. The equipment was used to provide services to our customers for which we paid a service fee. On February 9, 2007, we purchased the remaining partnership interest for $47.8 million, and as a result acquired the partnership equipment. The acquisition of the partnership controlling interest was accounted for as an asset purchase.

At September 30, 2007, 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, 2008, 2009, 2010, 2011 and 2012 are $60.6 million, $50.2 million, $33.7 million, $29.7 million and $18.6 million, respectively and $7.8 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, 2007 (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 | $ 53,346 | $ 53,336 | $ 10 | $ — | $ — |
| Guarantees | 193,392 | 81,567 | 65,595 | 15,658 | 30,572 |
| Total Other Commercial Commitments | $246,738 | $134,903 | $65,605 | $15,658 | $30,572 |

The following table summarizes our contractual obligations and other commercial commitments as of September 30, 2007 (in thousands):

| Contractual Obligations | Total | Less than 1 year | 1-3 Years | 4-5 Years | After 5 Years |
|---|---|---|---|---|---|
| Long term and short term debt | $ 671,268 | $ 421,268 | $250,000 | $ — | $ — |
| Interest on long term debt and capital leases | 69,423 | 26,296 | 28,752 | 14,375 | — |
| Capital lease obligations | 2,949 | 867 | 1,146 | 936 | — |
| Operating leases | 74,956 | 6,703 | 3,716 | 51,634 | 2,904 |
| Equipment financing arrangement[1] | 54,649 | 12,990 | 41,659 | — | — |
| Purchase obligations[2] | 392,576 | 388,576 | 4,000 | — | — |
| Purchase commitments[3] | 101,822 | 26,317 | 41,032 | 30,643 | 3,830 |
| Other long-term liabilities[4] | 91,449 | 90,777 | 144 | 96 | 432 |
| Total contractual cash obligations | $1,559,092 | $1,013,794 | $440,449 | $97,684 | $7,166 |

(1) As discussed previously, we have the option, but not the obligation, to purchase the pumping service equipment in this partnership for approximately $32 million in 2010. 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 reportable segment for the year ended September 30, 2007, are as follows (in thousands):

| | U.S./Mexico Pressure Pumping | International Pressure Pumping | Canada Pressure Pumping | Oilfield Services Group | Total |
|---|---|---|---|---|---|
| Balance September 30, 2005 | $271,781 | $255,101 | $117,807 | $240,523 | $885,212 |
| Acquisitions | — | 176 | — | 42,909 | 43,085 |
| Balance September 30, 2006 | $271,781 | $255,277 | $117,807 | $283,432 | $928,297 |
| Acquisitions | 1,314 | 1,074 | — | 34,217 | 36,605 |
| Resolution of tax contingency | | | (965) | | (965) |
| Balance September 30, 2007 | $273,095 | $256,351 | $116,842 | $317,649 | $963,937 |

Goodwill increased $36.6 million in fiscal 2007, as the result of acquisitions discussed in Note 3. This increase was reduced by a $1.0 million decrease in goodwill due to the utilization of tax attributes that were acquired in prior acquisitions.

Technology based intangible assets net of accumulated amortization were $28.9 million and $19.7 million at September 30, 2007 and 2006, respectively. Amortization for the three years ended September 30, 2007, 2006 and 2005 was $2.2 million, $0.7 million and $0.5 million, respectively.

### 12. Supplemental Financial Information

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

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Consolidated statement of operations: | | | |
| Research and development expense | $ 25,714 | $ 24,263 | $ 21,172 |
| Rent expense | 73,051 | 74,222 | 75,811 |
| Net operating foreign exchange gain | (417) | (1,303) | (740) |
| Consolidated statement of cash flows: | | | |
| Income tax paid | 373,109 | 336,230 | 187,195 |
| Interest paid | 39,016 | 8,393 | 8,078 |
| Details of acquisitions: | | | |
| Fair value of assets acquired | 27,712 | 51,044 | — |
| Liabilities assumed | 5,617 | 31,324 | — |
| Goodwill[1] | 35,825 | 43,085 | — |
| Cash paid for acquisitions, net of cash acquired | 57,920 | 52,172 | — |

[1] Includes step acquisition entries for BJSP in fiscal 2006 (see Note 3).

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

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Minority interest | (11,315) | (3,970) | (3,725) |
| Non-operating net foreign exchange gain / (loss) | (88) | (1,800) | 746 |
| Gain on insurance recovery | 1,406 | 1,099 | 239 |
| Gain from equity method investments | 520 | 432 | 1,546 |
| Recovery of misappropriated funds (see below) | — | 2,791 | 9,020 |
| Reversal of excess liabilities in Asia Pacific (see below) | — | — | 9,484 |
| Other, net | 2,893 | 1,437 | (1,352) |
| Other (expense) income, net | $ (6,584) | $ (11) | $15,958 |

### Recovery of misappropriated funds/Reversal of excess liabilities

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 former Region Controller pled guilty to one count of theft in Singapore and received a 21 month prison sentence there on May 7, 2007. 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 June 2007, the Company filed a civil lawsuit against the former Region Controller seeking to recover any additional misappropriated funds and seeking an accounting of disbursements that could not be explained following the investigation.

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*.

During 2007, the investigation identified another payment of $300,000 made in a prior year to the same entity that may have been used to make illegal payments to government officials.

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. Some of these payments may have been proper, but the circumstances surrounding others suggest that 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 has engaged in 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 has engaged in 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 ("FCPA") 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. Recent civil and criminal settlements have included multi-million dollar fines, deferred prosecution agreements, guilty pleas, and other sanctions, including the requirement that the corporation retain a monitor to oversee the corporation's compliance with the FCPA. Furthermore, corporations that have entered into prior consent decrees regarding the FCPA are potentially subject to greater penalties. The Company entered into a consent decree with the SEC in 2004 following an investigation into improper payments in Argentina.

We have had 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.

### 13. Employee Stock Plans

We currently have three incentive plans and an Employee Stock Purchase Plan. 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. The Plans also provide for the granting of performance awards to our officers and the 2003 Plan provides for restricted stock awards to our non-employee directors. An aggregate of 32.0 million shares of Common Stock has been authorized for grants under the Plans, of which 9.9 million shares were available for future grants at September 30, 2007. 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, 2007.

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 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 2007 and 2006 and under APB 25 for fiscal 2005, which was allocated as follows (in thousands):

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Cost of sales and services | $ 7,168 | $ 3,786 | $ 2,089 |
| Research and engineering | 1,484 | 1,163 | 860 |
| Marketing | 3,359 | 2,374 | 1,720 |
| General and administrative | 18,615 | 11,013 | 8,491 |
| Stock based compensation expense | 30,626 | 18,336 | 13,160 |
| Tax benefit | (7,678) | (3,631) | (4,803) |
| Stock based compensation expense, net of tax | $22,948 | $14,705 | $ 8,357 |

The following table illustrates the effect on net income and earnings per share in fiscal 2007 and 2006 compared with the pro forma effect on net income and earnings per share in fiscal 2005 if we had applied the fair value recognition provisions of SFAS 123 to our stock options and shares reserved under the Purchase Plan (in thousands, except per share amounts):

| | Actual 2007 | Actual 2006 | Pro Forma 2005 |
|---|---|---|---|
| Net income, as reported | $753,640 | $804,610 | $453,042 |
| Add: total stock-based employee compensation expense included in reported net income, net of tax | 22,948 | 14,705 | 8,357 |
| Less: total stock-based employee compensation expense determined under SFAS 123(R) and SFAS 123, respectively, for all awards, net of tax | (22,948) | (14,705) | (17,258) |
| Net income | $753,640 | $804,610 | $444,141 |
| Earnings per share: | | | |
| Basic, as reported | $ 2.57 | $ 2.55 | $ 1.40 |
| Basic, pro forma | $ 2.57 | $ 2.55 | $ 1.37 |
| Diluted, as reported | $ 2.55 | $ 2.52 | $ 1.38 |
| Diluted, pro forma | $ 2.55 | $ 2.52 | $ 1.35 |

*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. The exercise history showed that officers tend to hold options for a longer period before exercising than non-officers. 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 the historical differences in exercise patterns exhibited. 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 | 2007 Actual | 2006 Actual | 2005 Pro forma |
|---|---|---|---|
| Expected life (years) | 4.8 | 5.0 | 4.7 |
| Interest rate | 4.6% | 4.4% | 3.6% |
| Volatility | 37.0% | 42.8% | 30.4% |
| Dividend yield | 0.6% | 0.6% | 0.7% |
| Weighted-average fair value per share at grant date | $12.08 | $14.68 | $6.99 |
| **Non-officer grants** | | | |
| Expected life (years) | 3.7 | 3.0 | 4.7 |
| Interest rate | 4.6% | 4.4% | 3.6% |
| Volatility | 33.4% | 31.9% | 30.4% |
| Dividend yield | 0.6% | 0.6% | 0.7% |
| Weighted-average fair value per share at grant date | $ 9.84 | $ 9.19 | $6.99 |

A summary of stock option activity and related information is presented below (in thousands, except per share prices) as of September 30, 2007:

| | | Weighted-Average | | |
|---|---|---|---|---|
| | Shares | Exercise Price | Remaining Contractual Term | Intrinsic Value |
| Outstanding at beginning of year | 9,103 | $18.12 | | |
| Granted | 1,790 | 32.51 | | |
| Exercised | (542) | 14.82 | | |
| Forfeited | (281) | 32.19 | | |
| Outstanding at end of year | 10,070 | 20.46 | 3.1 | $84,092 |
| Options exercisable at year-end | 7,099 | 15.68 | 2.1 | 82,496 |
| Weighted-average grant date fair value of options granted during the year | | $10.69 | | |

The weighted-average grant date fair value of options granted during fiscal 2007, 2006 and 2005 was $10.69, $11.70 and $6.99, respectively. The total intrinsic value of options exercised during the years ended September 30, 2007, 2006 and 2005 was $7.8 million, $21.1 million and $48.2 million, respectively.

A summary of the status of unvested shares as of September 30, 2007, and changes during fiscal 2007, is presented below (in thousands, except per share prices):

| | Shares | Weighted-Average Grant-Date per Share Fair Value |
|---|---|---|
| Unvested at October 1, 2006 | 3,278 | $ 9.04 |
| Granted | 1,790 | 10.69 |
| Vested | (1,831) | 8.38 |
| Forfeited | (266) | 9.46 |
| Unvested at September 30, 2007 | 2,971 | $10.40 |

As of September 30, 2007, there was $30.9 million of total unrecognized compensation cost related to unvested stock options. That cost is expected to be recognized over a weighted-average period of 3.1 years. The total fair value of shares vested during the years ended September 30, 2007, 2006 and 2005 was $15.3 million, $9.6 million and $17.0 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 ratably 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.

*Stock Incentive Awards:* For awards made under the 1997 Stock Incentive Plan and 2000 Stock Incentive Plan, we have reserved 334,417 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. 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. Expense for stock incentive awards was $1.5 million, $3.6 million and $12.3 million in fiscal 2007, 2006 and 2005, respectively.

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, 2007, we have accrued $1.9 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 were not met for the fiscal 2005 or fiscal 2004 grant. In accordance with SFAS 123(R), no compensation expense was reversed for the fair value of this award, however, $3.2 million and $4.2 million was reversed for the cash award component in fiscal 2007 and 2006, respectively.

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, 2007 and assumptions used to determine the fair value are listed below:

| Fiscal Year | Granted | Forfeited | Canceled | Outstanding | Volatility | Dividend Yield | Weighted Average Fair value per share |
|---|---|---|---|---|---|---|---|
| 2007 | 113,180 | 19,601 | — | 93,579 | 33.41% | 0.61% | $45.28 |
| 2006 | 206,779 | 39,063 | — | 167,716 | 45.54% | 0.31% | $30.52 |
| 2005 | 282,912 | 39,426 | 243,486 | — | 52.05% | 0.60% | $25.83 |

As of September 30, 2007, there was $3.1 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, 2007, 2006 and 2005.

In fiscal 2007, we also granted our officers an award of common stock of our Company with no exercise price. As there is no exercise price for the awards granted, the fair value of these awards is equal to our Company's stock price on the date of grant. These awards vested quarterly during calendar year 2007 contingent upon achievement of certain financial performance goals over the stipulated period. In addition, each officer was also awarded cash equal to his or her tax liability on the common stock they received, if any, at the end of the performance period. Fiscal 2007 expense for the common stock award and the related cash award was $3.6 million.

*Purchase Plan:* We issued a total of 650,008 shares in fiscal 2007 under the Purchase Plan, and have reserved 919,885 shares for fiscal 2008. Compensation expense determined under SFAS 123(R) for the year ended September 30, 2007 was calculated using the Black-Scholes option pricing model with the following assumptions:

| | 2007 Actual | 2006 Actual | 2005 Pro forma |
|---|---|---|---|
| Expected life (years) | 1.0 | 1.0 | 1.0 |
| Interest rate | 4.9% | 4.1% | 4.1% |
| Volatility | 39.1% | 29.6% | 16.4% |
| Dividend yield | 0.7% | 0.6% | 0.6% |
| Weighted-average fair value per share at grant date | $8.81 | $9.35 | $5.49 |

We calculated estimated volatility using historical daily prices based on the appropriate expected life of the Purchase Plan. The risk-free interest rate is based on observed U.S. Treasury rates appropriate for the expected life of the 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:* We have paid cash dividends in the amount of $.04 per common share each quarter and $51.9 million in the aggregate annual amount in fiscal year 2005. We paid $.05 per common share each quarter and $64.3 million and $58.6 million in the aggregate annual amount for fiscal years 2006 and 2007, respectively. We anticipate paying cash dividends in the amount of $.05 per common share on a quarterly basis in fiscal 2008. 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.

*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 preferred share purchase right ("Right") 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 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 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 52,348,000 shares at a cost of $597.4 million through fiscal 2005. During fiscal 2006, we purchased a total of 31,725,882 shares at a cost of $1,133.3 million. During fiscal 2007, we purchased a total of 2,564,457 shares at a cost of $74.6 million. As of September 30, 2007, remaining authority to repurchase Common Stock is $394.7 million. Treasury shares have been utilized for our various stock plans as described in Note 13. A total of 1,110,321 treasury shares were used at a cost of $29.4 million in fiscal 2007, 1,509,000 treasury shares were used at a cost of $21.2 million in fiscal 2006, and 3,655,000 treasury shares were used at a cost of $45.2 million in fiscal 2005.

*Accumulated Other Comprehensive Income:* Accumulated other comprehensive income (loss) consists of the following (in thousands):

| | Pension Adjustments | Cumulative Translation Adjustment | Total |
|---|---|---|---|
| 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 |
| Changes | (11,740) | 40,551 | 28,811 |
| Balance, September 30, 2007 | $(41,911) | $93,555 | $51,644 |

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, 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) |
| Year Ended September 30, 2007: | | | |
| Foreign currency translation adjustment | $ 40,551 | $ — | $ 40,551 |
| Minimum pension liability adjustment | 4,572 | (1,300) | 3,272 |
| Adoption of SFAS 158 (Note 9) | (22,561) | 7,549 | (15,012) |
| Change in other comprehensive income | $ 22,562 | $(6,249) | $ 28,811 |

## 15. Quarterly Financial Data (Unaudited)

| | First Quarter | Second Quarter | Third Quarter | Fourth Quarter | Fiscal Year Total |
|---|---|---|---|---|---|
| | (in thousands, except per share amounts) | | | | |
| **Fiscal Year 2007:** | | | | | |
| Revenue | $1,183,940 | $1,186,638 | $1,152,518 | $1,279,313 | $4,802,409 |
| Gross profit(1) | 379,611 | 349,813 | 322,671 | 350,158 | 1,402,253 |
| Net income | 207,084 | 188,916 | 168,290 | 189,350 | 753,640 |
| Earnings per share: | | | | | |
| Basic | .71 | .64 | .57 | .65 | 2.57 |
| Diluted | .70 | .64 | .57 | .64 | 2.55 |
| **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 |

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

**ITEM 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure**

None.

**ITEM 9A. Controls and Procedures**

*Evaluation of disclosure controls and procedures.* Based on their evaluation of the Company's disclosure controls and procedures as of the end of the period covered by this report, the Chief Executive Officer and Chief Financial Officer of the Company have concluded that the Company's disclosure controls and procedures are effective.

*Changes in internal control over financial reporting.* There has been no change in the Company's internal controls over financial reporting during the quarter ended September 30, 2007 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting.

*Design and evaluation of internal control over financial reporting.* Management's Report on Internal Control over Financial Reporting and the Report of the Independent Registered Public Accounting Firm are set forth in Part II, Item 8 of this report and are incorporated herein by reference.

**ITEM 9B. Other Information**

None.

## PART III

### ITEM 10. Directors, Executive Officers and Corporate Governance

Information concerning the directors of the Company is set forth in the section entitled "Proposal 1: Election of Directors" in the Proxy Statement of the Company for the Annual Meeting of Stockholders to be held February 7, 2008, which section is incorporated herein by reference. For information regarding executive officers of the Company, see page 13 hereof. Information concerning compliance with Section 16(a) of the Exchange Act is set forth in the section entitled "Section 16(a) Beneficial Ownership Reporting Compliance" in the Proxy Statement of the Company for the Annual Meeting of Stockholders to be held February 7, 2008, which section is incorporated herein by reference.

Information concerning the Audit Committee of the Company and the audit committee financial expert is set forth in the section entitled "Board of Directors and Committees of the Board" in the Proxy Statement of the Company for the Annual Meeting of Stockholders to be held February 7, 2008, which section is incorporated herein by reference. Information concerning the Company's Code of Ethics is set forth in the section entitled "Code of Ethics" in the Proxy Statement of the Company for the Annual Meeting of Stockholders to be held February 7, 2008, which section is incorporated herein by reference.

### ITEM 11. Executive Compensation

Information for this item is set forth in the sections entitled "Director Compensation" and "Compensation Discussion and Analysis" in the Proxy Statement of the Company for the Annual Meeting of Stockholders to be held February 7, 2008, which sections is incorporated herein by reference.

### ITEM 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information for this item is set forth in the section entitled "Security Ownership of Certain Beneficial Owners and Management" in the Proxy Statement of the Company for the Annual Meeting of Stockholders to be held February 7, 2008, which sections are incorporated herein by reference.

### ITEM 13. Certain Relationships and Related Transactions, and Director Independence

Information for this item is set forth in the sections entitled "Related Party Transaction Policies and Procedures" and "Director Independence" in the Proxy Statement of the Company for the Annual Meeting of Stockholders to be held February 7, 2008, which section is incorporated herein by reference.

### ITEM 14. Principal Accountant Fees and Services

Information for this item is set forth in the section entitled "Fees Paid to Deloitte & Touche" in the Proxy Statement of the Company for the Annual Meeting of Stockholders to be held February 7, 2008, which section is incorporated herein by reference.

## 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.



(2) Financial Statement Schedules:



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:

| 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 (file no. 1-10570) 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). |

| 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 (file no. 1-10570) 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 (file no. 1-10570) 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 7, 2006 (filed as Exhibit 3.1 to the Company's Current Report of Form 8-K dated December 7, 2006 (file no. 1-10570) 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 (file no. 1-10570) and incorporated herein by reference). |
| 4.5 | 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 (file no. 1-10570) and incorporated herein by reference). |
| 4.6 | 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 (file no. 1-10570) and incorporated herein by reference). |
| 4.7 | 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 (file no. 1-10570) 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 | BJ Services Company 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). |

| Number | Description of Exhibit |
|---|---|
| †10.4 | Amendment effective December 12, 1996 to BJ Services Company 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 BJ Services Company 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 BJ Services Company 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 (file no. 1-10570) 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 (file no. 1-10570) and incorporated herein by reference). |
| †10.13 | BJ Services Company 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 BJ Services Company 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). |
| †10.15 | Amendment effective January 27, 2000 to BJ Services Company 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 BJ Services Company 1997 Incentive Plan (filed as Appendix C to the Company's Proxy Statement dated April 10, 2001 (file no. 1-10570) and incorporated herein by reference). |
| †10.17 | Fifth Amendment effective October 15, 2001 to BJ Services Company 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 (file no. 1-10570) and incorporated herein by reference). |
| †10.18 | Eighth Amendment effective November 15, 2006 to BJ Services Company 1997 Incentive Plan (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K filed on December 13, 2006 and incorporated herein by reference). |
| †10.19 | 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). |

| Number | Description of Exhibit |
|---|---|
| †10.20 | 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 (file no. 1-10570) and incorporated herein by reference). |
| †10.21 | 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 (file no. 1-10570) and incorporated herein by reference). |
| †10.22 | 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 (file no. 1-10570) and incorporated herein by reference). |
| †10.23 | 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 (file no. 1-10570) and incorporated herein by reference). |
| †10.24 | Fifth Amendment effective October 1, 2004 to BJ Services Company 1999 Employee Stock Purchase Plan (filed as Exhibit 10.51 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 (file no. 1-10570) and incorporated herein by reference). |
| †10.25 | BJ Services Company 2000 Incentive Plan (filed as Appendix B to the Company's Proxy Statement dated December 20, 2000 (file no. 1-10570) and incorporated herein by reference). |
| †10.26 | 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). |
| †10.27 | 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 (file no. 1-10570) and incorporated herein by reference). |
| †10.28 | 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 (file no. 1-10570) and incorporated herein by reference). |
| †10.29 | Fifth Amendment effective November 15, 2006 to BJ Services Company 2000 Incentive Plan (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K filed on December 13, 2006 (file no. 1-10570) and incorporated herein by reference). |
| †10.30 | 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 (file no. 1-10570) and incorporated herein by reference). |
| †10.31 | 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 (file no. 1-10570) incorporated herein by reference). |
| †10.32 | 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 (file no. 1-10570) incorporated herein by reference). |
| †10.33 | Second Amendment effective November 15, 2006 to BJ Services Company 2003 Incentive Plan (filed as Exhibit 10.5 to the Company's Current Report on Form 8-K filed on December 13, 2006 and (file no. 1-10570) incorporated herein by reference). |
| †10.34 | BJ Services Company 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 (file no. 1-10570) and incorporated herein by reference). |

| Number | Description of Exhibit |
|---|---|
| †10.35 | 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 (file no. 1-10570) and incorporated herein by reference). |
| †10.36 | Second Amendment effective March 1, 2007 to BJ Services Company Supplemental Executive Retirement Plan (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K dated May 24, 2007 (file no. 1-10570) and incorporated herein by reference). |
| †10.37 | 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). |
| †10.38 | BJ Services Company 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 (file no. 1-10570) and incorporated herein by reference). |
| †10.39 | Amendment effective January 1, 2003 to BJ Services Company Directors' Benefit Plan, (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2003 (file no. 1-10570) and incorporated herein by reference). |
| †10.40 | BJ Services Company 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 (file no. 1-10570) and incorporated herein by reference). |
| †10.41 | First Amendment effective January 1, 2002 to BJ Services Company Deferred Compensation Plan (filed as Exhibit 10.50 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 (file no. 1-10570) and incorporated herein by reference). |
| †10.42 | 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 (file no. 1-10570) and incorporated herein by reference). |
| 10.43 | 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). |
| 10.44 | Amended and Restated 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). |
| 10.45 | Amended and Restated Credit Agreement, dated as of August 30, 2007, among the Company, Citibank, N.A., as administrative agent, swing line lender and L/C issuer, Bank of America, N.A. as syndication agent and L/C issuer, The Royal Bank of Scotland PLC, JPMorgan Chase Bank, N.A. and The Bank of Tokyo-Mitsubishi UFJ, Ltd. as co-documentation agents and certain lenders named therein (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K dated August 30, 2007 (file no. 1-10570 and incorporated herein by reference). |
| †10.46 | 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 (file no. 1-10570) and incorporated herein by reference). |
| †10.47 | 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 (file no. 1-10570) and incorporated herein by reference). |

| Number | Description of Exhibit |
|---|---|
| †10.48 | Form of letter agreement setting forth terms and conditions of performance units awarded to executive officers of the Company on November 17, 2004 (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K, filed on November 23, 2004 (file no. 1-10570) 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 on November 17, 2004 (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K, filed on November 23, 2004 (file no. 1-10570) 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 executive on November 17, 2004 (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K, filed on November 23, 2004 (file no. 1-10570) 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 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 (file no. 1-10570) 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 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 (file no. 1-10570) 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 1998 (filed as Exhibit 10.56 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 (file no. 1-10570) 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 1999 (filed as Exhibit 10.57 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 (file no. 1-10570) 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 2001 (filed as Exhibit 10.58 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 (file no. 1-10570) and incorporated herein by reference). |
| †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 2002 (filed as Exhibit 10.59 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 (file no. 1-10570) 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 2003 (filed as Exhibit 10.60 to the Company's Annual Report on Form 10-K for the year ended September 30, 2004 (file no. 1-10570) and incorporated herein by reference). |
| †10.58 | 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 (file no. 1-10570) and incorporated herein by reference). |
| †10.59 | 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 (file no. 1-10570) and incorporated herein by reference). |

| Number | Description of Exhibit |
|---|---|
| †10.60 | 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 (file no. 1-10570) 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 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 (file no. 1-10570) and incorporated herein by reference). |
| †10.62 | Form of amended 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 December 13, 2006 (file no. 1-10570) and incorporated herein by reference). |
| †10.63 | Form of amended 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 December 13, 2006 (file no. 1-10570) 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 (filed as Exhibit 10.64 to the Company's Annual Report on Form 10-K for the year ended September 30, 2006 (file no. 1-10570) and incorporated herein by reference). |
| †10.65 | Form of letter agreement setting forth terms and conditions of bonus stock awarded to executive officers during fiscal 2007 (filed as Exhibit 10.65 to the Company's Annual Report on Form 10-K for the year ended September 30, 2006 (file no. 1-10570) and incorporated herein by reference). |
| †10.66 | Form of letter agreement setting forth terms and conditions of phantom stock awarded to executive officers during fiscal 2007 (filed as Exhibit 10.66 to the Company's Annual Report on Form 10-K for the year ended September 30, 2006 (file no. 1-10570) and incorporated herein by reference). |
| †10.67 | Form of letter agreement setting forth terms and conditions of phantom stock awarded to non-employee directors during fiscal 2007 (filed as Exhibit 10.67 to the Company's Annual Report on Form 10-K for the year ended September 30, 2006 (file no. 1-10570) and incorporated herein by reference). |
| †10.68 | Description of Equity and Long-Term Incentive Grants for fiscal 2007 (filed on the Company's Current Report on Form 8-K filed on November 21, 2006 (file no. 1-10570) and incorporated herein by reference). |
| †*10.69 | Form of letter agreement setting forth terms and conditions of options to purchase shares of performance units awarded to executive officers during fiscal 2007 under the 2003 Incentive Plan. |
| *12.1 | Ratio of Earnings to Fixed Charges |
| *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. |
| *32.2 | Section 906 certification furnished for Jeffrey E. Smith. |

* 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 /s/ J.W. STEWART

**J. W. Stewart**
**President and Chief Executive Officer**

Date: November 29, 2007

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

| Signature | Title | Date |
|---|---|---|
| /s/ J.W. STEWART<br>**J.W. Stewart** | Chairman of the Board, President, and Chief Executive Officer (Principal Executive Officer) | November 29, 2007 |
| /s/ JEFFREY E. SMITH<br>**Jeffrey E. Smith** | Senior Vice President—Finance, and Chief Financial Officer (Principal Financial Officer) | November 29, 2007 |
| /s/ BRIAN T. MCCOLE<br>**Brian T. McCole** | Vice President—Controller (Principal Accounting Officer) | November 29, 2007 |
| /s/ L. WILLIAM HEILIGBRODT<br>**L. William Heiligbrodt** | Director | November 29, 2007 |
| /s/ JOHN R. HUFF<br>**John R. Huff** | Director | November 29, 2007 |
| /s/ DON D. JORDAN<br>**Don D. Jordan** | Director | November 29, 2007 |
| /s/ WILLIAM H. WHITE<br>**William H. White** | Director | November 29, 2007 |
| /s/ MICHAEL E. PATRICK<br>**Michael E. Patrick** | Director | November 29, 2007 |
| /s/ JAMES L. PAYNE<br>**James L. Payne** | Director | November 29, 2007 |

## BJ SERVICES COMPANY

## SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS
### For the Years Ended September 30, 2007, 2006 and 2005
### (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, 2007** | | | | | |
| Allowance for doubtful accounts receivable | $18,976 | $6,541 | $ — | $(4,967)[1] | $20,550 |
| Reserve for inventory obsolescence | 22,372 | 8,351 | — | (6,070)[2] | 24,653 |
| **YEAR ENDED SEPTEMBER 30, 2006** | | | | | |
| Allowance for doubtful accounts receivable | $13,938 | $5,920 | $3,228[3] | $(4,110)[1] | $18,976 |
| Reserve for inventory obsolescence | 17,429 | 3,031 | 4,002[3] | (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 |

(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) Additions related to acquisitions.

# 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 February 7, 2008
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.

On February 28, 2007 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.

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BJ SERVICES COMPANY
4601 Westway Park Blvd.
P. O. Box 4442
Houston, Texas 77210-4442

END