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J Services Co

2008 ANNUAL REPORT

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Selected Highlights

- The Company's revenue increased 13% in fiscal 2008 versus fiscal 2007, with all of our reportable segments showing revenue growth.

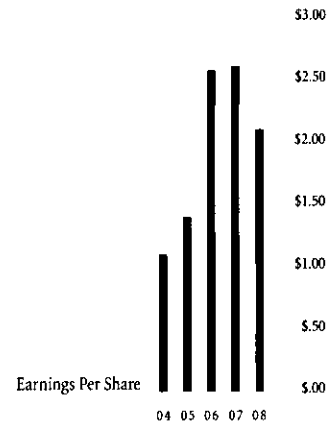
- Operating income was $907 million in fiscal 2008 versus $1,151 million in fiscal 2007. Operating income as a percentage of revenue declined from 24% in 2007 to 17% in 2008. Declining prices for our products and services in the North American market, as well as increased material and fuel costs led to the overall decline in operating income margin.

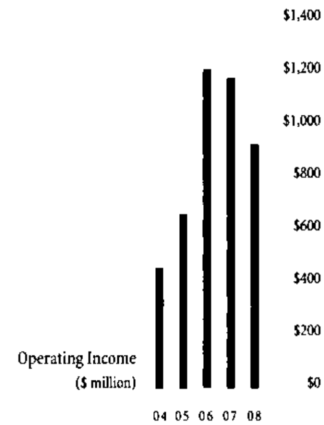
- Cash flow from operating activities was $899 million, compared to $841 in fiscal 2007. During the year, we invested $607 million in plant and equipment, used $57 million for acquisitions, paid $59 million in dividends and repaid $115 million in debt.

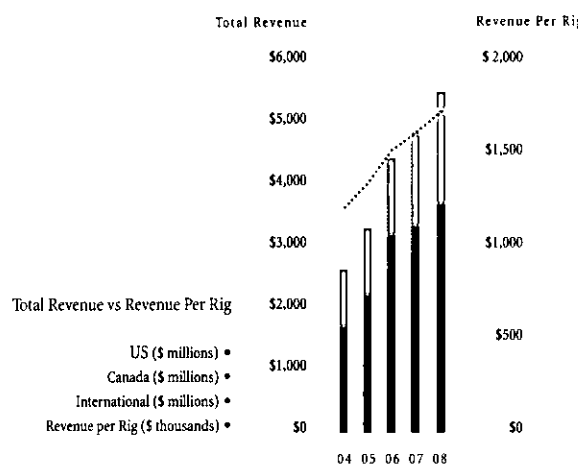
Summary of Selected Financial Data

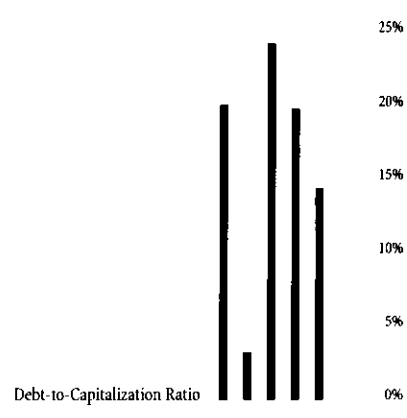
(in thousands, except per share amounts)	**2008**	2007
Revenue	**$5,426,262**	$4,802,409
Operating income	**907,097**	1,150,539
Income before taxes	**868,146**	1,112,848
Net income	**609,365**	753,640
Basic earnings per share	**2.08**	2.57
Diluted earnings per share	**2.06**	2.55
Total assets	**5,321,908**	4,715,212
Total interest-bearing debt	**556,340**	671,028
Stockholders' equity	**3,441,807**	2,851,398
Cash flow from operations	**898,794**	840,657
Capital expenditures	**606,866**	752,113
Employees	**18,000**	16,700

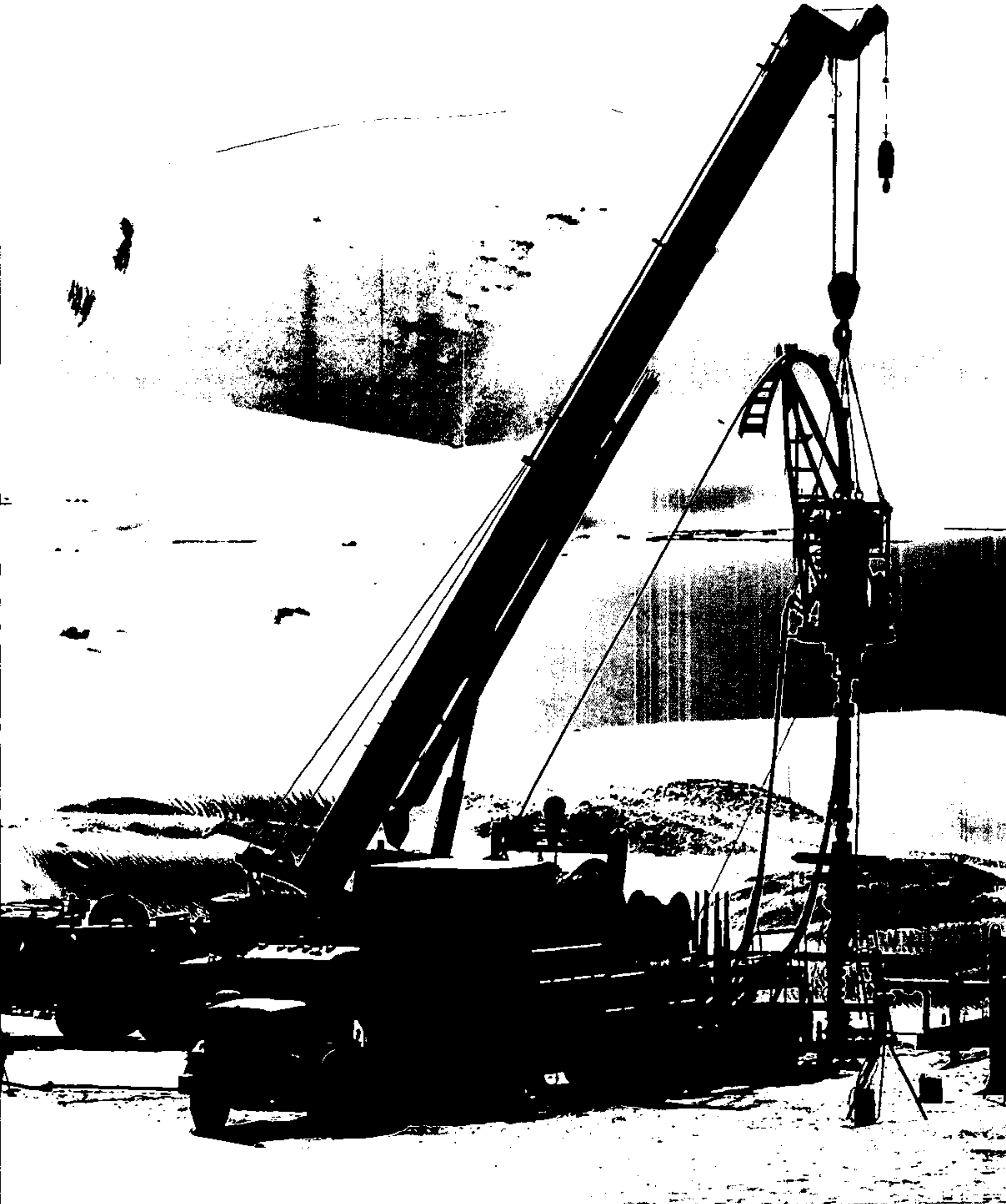
BJ Services Company is listed on the New York Stock Exchange; its common stock trades under the symbol "BJS." The Company's core business consists of cementing, stimulation and coiled tubing services worldwide. The Company also provides completion tools, tool services, completion fluids, tubular services,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











Left: Proprietary coiled tubing technologies contributed to an increase in Middle East revenues.

Right: The Tubular Services team prepares drillpipe for deepwater operations in Brazil.

Safety Accomplishments for 2008

- Launched a number of safety initiatives as part of the Company's continuous improvement strategy, which led to a cumulative 19.5% reduction in the Total Recordable Injury Rate (TRIR) over 2 years.

- Significant investment was made to address at-risk driving habits by deploying 900 "in-cab driver monitors" throughout 18 U.S. facilities; each facility is seeing a monthly reduction of risky events per driver.

- Working with a key manufacturer to raise industry safety standards through the development and pilot program for an innovative Hammerless Union tool that is designed to reduce risk at the wellsite.

- Worked alongside a major energy producer and key service companies to develop and establish new standards for temporary pipework, as well as a Goal Zero approach to workplace hazards with the creation of a 'Zero - It's Our Number One Number' DVD to communicate the industry vision.

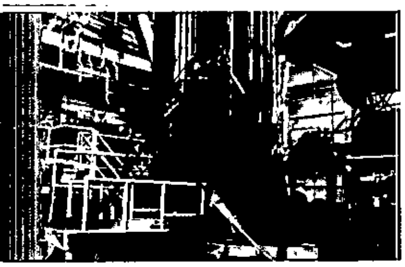
- Environmental stewardship: worked with customers and regulatory bodies to ensure that we left a clean footprint at customer job sites and BJ Services facilities.

Letter to Stockholders

The Company generated record revenue of $5.4 billion in fiscal 2008, up 13% from the prior year and earnings per diluted share was $2.06. Cash flow from operations for the year was $899 million and the Company's debt to capitalization ratio at September 30, 2008 was 13.9%. During the year, cash generated from operations was used for the investment of $607 million in plant and equipment for the business, $57 million for acquisitions of businesses, $115 million for the repayment of debt and payment of $59 million in dividends to our stockholders. Following the end of the fiscal year, the Company purchased $44 million in Company Stock (3.5 million shares). Since the Company began its share repurchase program in 1997, the Company has purchased 90.2 million shares for $1.9 billion, representing approximately 24% of the shares that would have been outstanding as of September 30, 2008 without these repurchases.

Market Conditions

Natural gas prices for the year in the U.S. averaged $9.04 per thousand cubic feet. The price was $6.04 at the beginning of the year, $7.18 at the end of the year and peaked in July at $13.31. Just prior to the date of this letter, natural gas price was $5.68. The prolific shale formation gas wells completed during the year contributed to the year-over-year increase in gas production, and coupled with demand reduction, have led to the lower current natural gas price.



Crude oil prices for the year averaged $107.84 per barrel. The price was $80.24 at the beginning of the year, $100.64 at the end of the year and peaked at $145.29 in July. Just prior to the date of this letter, crude oil price was $43.52 per barrel. The credit crisis, lower demand due to the high crude oil prices earlier in the year and hedge fund liquidations (reduced speculation on higher prices) contributed to the current lower crude oil price.

Drilling activity in the U.S. was up 6% for the fiscal year while in Canada drilling activity was flat. Outside North America, average drilling activity was up 7% from the prior year with gains in each of our operating regions. The industry continues to operate at high levels of drilling activity; however, with recent declines in commodity prices, North American activity is expected to be down in 2009.

Pressure Pumping Results

Pressure pumping service operations in our U.S./Mexico division achieved record revenue for the year with revenue up 8% from the prior year. Average drilling activity increased 6% in the U.S. and 11% in Mexico. Operating income margins were 22%, down from 34% in the prior year. Increased competition with modest activity growth resulted in lower service prices and margin compression compared to the prior year. Canadian pressure pumping revenue was up 14% from the prior year with average rig count flat. Operating income was up 6% from the prior year.

Outside North America, drilling activity increased 7% and our international pressure pumping operations achieved 17% revenue growth and a 13% increase in operating income.

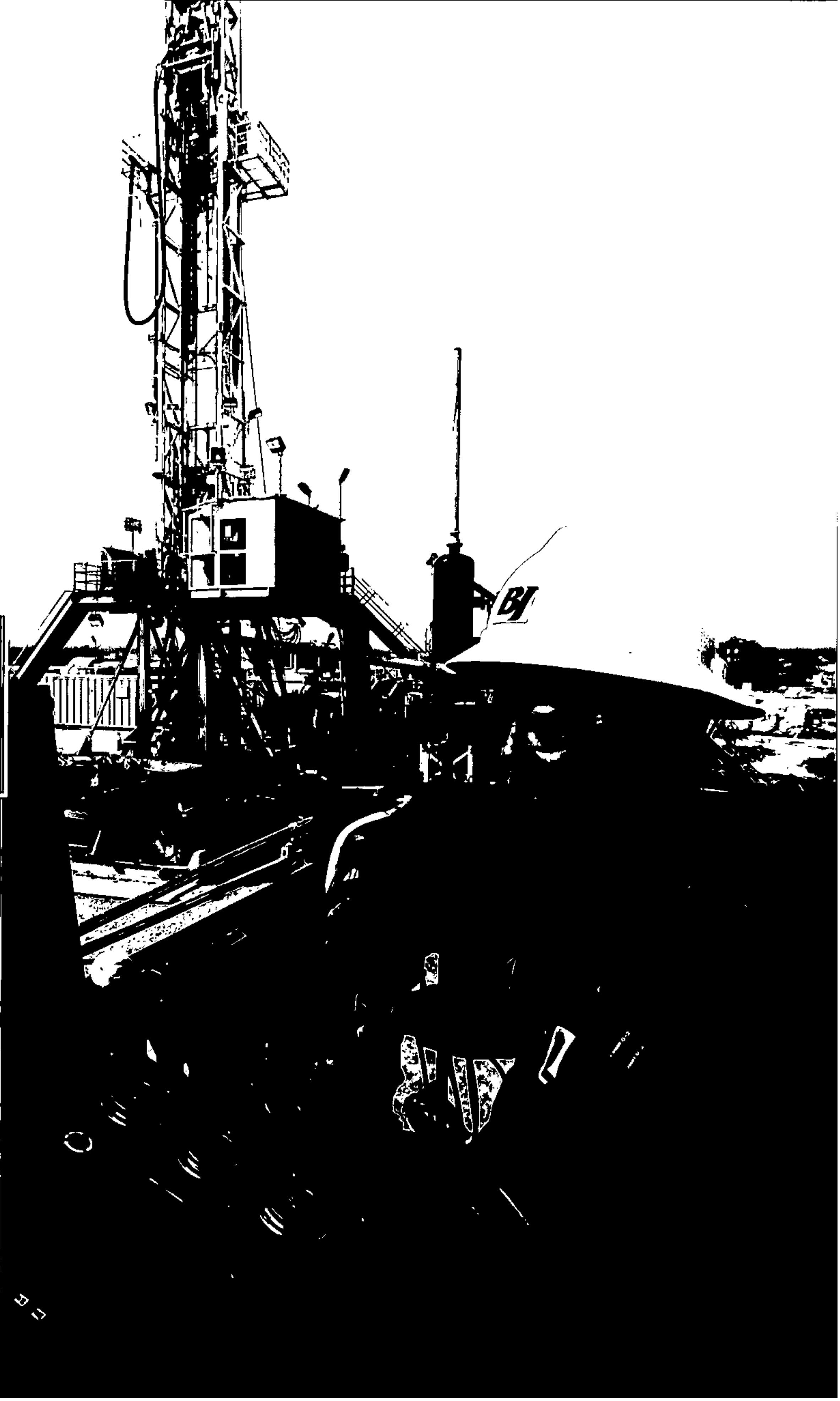
Oilfield Services Results

Oilfield Services Group revenue was up 23% and operating income improved by 12%, compared to the prior year. All but one of the service lines experienced double-digit revenue growth with Process and Pipeline Services, Chemical Services and Completion Tools achieving greater than 30% revenue growth compared to the prior year. We continue to integrate the group's service and product offerings throughout our global operations. With revenues of $954 million for the year, the Oilfield Services Group is making a material contribution to the Company's financial results.

Expansions

U.S./Mexico Pressure Pumping—Unconventional shale development has become increasingly important for supplying natural gas to the United States. To keep pace with the exploitation of gas shale development, we expanded our fracturing service offering into Searcy, Arkansas, which resides in the boundaries of the Fayetteville Shale. We began operations with a temporary facility and will complete a new facility in 2009 capable of supporting all of our service lines. The Marcellus Shale in the Northeast has also become a market with increasing importance to the supply of natural gas. During 2008, we increased our capacity in this market to meet the growing demand for fracturing. We also introduced Tubular Services into the Marcellus market, beginning our first land-based tubular services operation in the U.S. The momentum of oil shale development in the northern U.S. also increased during the year. We expanded our facility in Dickinson, North Dakota, to provide stimulation services to our customers operating in the Bakken Shale area, an oil shale market with increasing importance to supplying oil to the U.S. In Mexico, we were awarded the first offshore integrated services project with another large oilfield service provider. On this project, which is expected to begin during our second fiscal quarter of 2009, we will provide cementing, drilling fluids, and casing and tubular services. This project will complement our existing base of business and will further increase our integrated project involvement.

International Pressure Pumping—The Latin America region experienced strong revenue growth performance with revenue up 28% compared to the prior year. Improved market conditions in Argentina, Venezuela and Brazil as well as additional fracturing and coiled tubing capacity in the region fueled the revenue growth. This time last year we were awarded a stimulation vessel contract for a new vessel in Brazil. The vessel, the *Blue Marlin*, was recently completed and commissioned, and began generating revenue in our first fiscal quarter of 2009. Also in Brazil, we were awarded a significant coiled tubing contract that will be an important contributor to revenue growth in 2009.

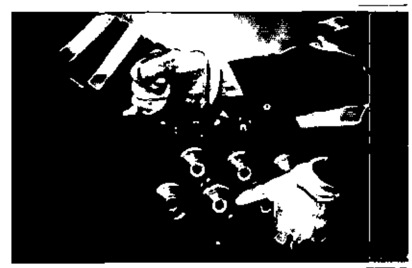


Left: The new *Blue Marlin* stimulation vessel was recently commissioned in Brazil and began work in December 2008.

Right: BJ Services engineers continually push the envelope of cementing technology to help operators overcome technical obstacles to worldwide oil and gas development.

Revenue from our Middle East region increased 27% in fiscal 2008 compared to the prior year. We were awarded contracts working offshore India with two stimulation vessels—the *Discovery*, which moved into the India market from the Gulf of Mexico; and the *Vestfonn*, which relocated from the North Sea. Redeployment of these assets into the India market increased their utilization and profit margins. We also entered the fracturing market in Algeria during fiscal 2008, winning a number of contracts during the year, which we believe will further benefit comparative results in fiscal 2009. We successfully introduced a number of new proprietary coiled tubing technologies into certain Middle East markets during fiscal 2008, including our StimTunnel™ acid tunneling service and our LEGS™ lateral entry guidance system.

The Asia Pacific region achieved revenue growth of 15% for the year. We significantly expanded our fracturing revenue in Australia during 2008, a strategy we embarked upon in 2007. We performed multiple OptiFrac™ coiled tubing fracturing jobs in China, expanding our fracturing capabilities in the country. We commissioned a number of state-of-the-art Seahawk™ offshore cementing units, and the commissioning of these units positions the Company well for increasing its market position in offshore cementing in 2009. The region built upon its 2007 expansion efforts for the DynaCoil™ capillary business by winning service contracts in Thailand, Indonesia and the Philippines. The region also established a new world record for running perforating guns on coiled tubing to a total length of 3,281 feet (1000 meters).



Oilfield Services Group—Completion Tools led the Oilfield Services Group with 42% revenue growth compared to the prior year. Our acquisition of the Innicor product line in May accounted for much of this growth. In addition, Completion Tools experienced significant growth in international revenue, with half of its revenue coming from international markets for the year. This is a substantial increase from when we first entered this business with the acquisition of OSCA in 2002 and is an example of efficient international expansion using BJ Services' international infrastructure. Completion Tools now has operations in Latin America, West Africa, the Middle East and Asia Pacific regions. Much of the growth achieved has been based on innovative product design for multizone well completions and high-pressure conditions.

Our Process and Pipeline Services (PPS) business achieved 37% revenue growth for the year, achieving record revenue and profit for the year. PPS is now the largest revenue producer for the Oilfield Services Group, with operations in almost all regions of the world. During the year, PPS provided its services on pipeline commissioning projects in Russia and India, pipeline projects in Australia, production platform projects in the Gulf of Mexico, and floating production, storage and offloading (FPSO) vessel and offshore platform projects in Africa, among other projects. Much of the work done by PPS is on longer-term commitments for infrastructure projects throughout the world.

Left: New capillary tubing systems contributed to the Chemical Services revenue growth.

Right: PPS provides turnkey services during umbilical system construction and installation, ensuring their cleanliness and integrity.

Left: The Innicor acquisition expands BJ's manufacturing capabilities with a 72,000-ft^2 facility where quality control measures are in place to ensure technology reliability in the field.

Right: BJ's wellbore model allows researchers to simulate gravel transport and packing dynamics in an 8-in. open hole environment.

Our Chemical Services business achieved more than 30% revenue growth for the year, also achieving record revenue and profit for the year. Chemical Services expanded both its U.S. and international revenues for the year with much of the international growth driven by growth from the DynaCoil™ capillary system product line. Capillary manufacturing capacity was expanded during the year and current year plans provide for the addition of a number of new capillary systems for both the U.S. and international markets.

Technology

The Company established a New Product Fundamental Research Group at its technology center in Tomball, Texas, and staffed the group with scientists focused on developing new products that will keep the Company on the leading edge of technology. The group was established in January and is currently focusing on 20 projects. Executive management from the Company meets with the group periodically and reviews progress on each of the projects. We believe this focused effort will provide for rapid new product development.

In the area of stimulation technology, the Company significantly increased its fracturing revenue using LiteProp™ 108 ultra-lightweight proppant following its introduction in 2007. Production of the proppant is being increased to meet higher customer demand in the current fiscal year.

The Company converted to environmentally friendly fracturing fluids throughout its U.S. operations. Although more expensive than conventional fracturing fluids, eco-friendly fluids are consistent with general trends in the industry and the Company's desire to be the leader in stimulation technology.

Additional chemical product developments for the year included the redesign of several of our fracturing and cementing chemical additives to reduce product costs for the Company. Highlights of this effort include the introduction of BJ Services' proprietary GasFlo™ surfactant to enhance gas production in shale formations. Finally, the Company filed for 60 new patents and had 22 new patents issued during the year in the U.S.

Acquisition

In May, the Company purchased Innicor Subsurface Technologies Inc., adding an important complement to the Company's Completion Tools product line. Innicor is a Calgary-based designer, manufacturer and provider of tools and equipment used in the completion and production phases of oil and gas well development. Innicor sells its products in Canada and select international locations. Our strategy will be to expand and grow the Innicor product offering into the various world markets where BJ Services has established operations, providing efficient growth in revenue from this product line. Innicor results are included with the Completion Tools business in our Oilfield Services Group.

Left: BJ Services is committed to operating our business as a valued neighbor in the communities in which we reside and work.

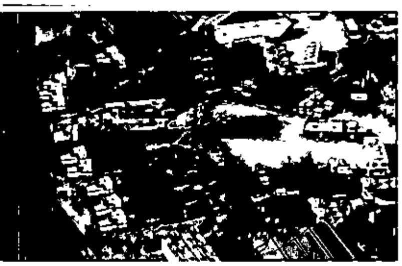
Right: BJ Services has earned a reputation for providing reliable fracturing services for virtually every major shale oil and gas operator.

Company Financial Strength

The Company has significant financial strength to allow it to effectively endure market activity reduction that may occur in the coming year. The Company generates significant cash flow to finance operating costs, capital expenditures, treasury share purchases and dividend payments. The cash flow in excess of these needs is used to pay its debt obligations as they come due. At the end of the fiscal year, the Company had $150 million in short-term investments. The Company has short-term borrowing capacity through a $400 million revolving credit facility that is committed through August 2012, which can be drawn upon with short notice. The Company's $500 million long-term debt obligation is in the form of $250 million 5.75% senior notes due in 2011 and $250 million 6% senior notes due in 2018, both of which the Company expects to pay on the due dates.

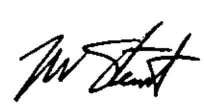
Market Outlook

Most economists are of the opinion that the world economies are headed for recession in 2009. Consequently, demand for oil and

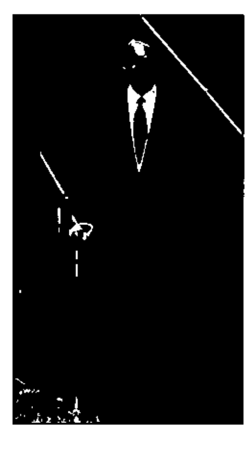


natural gas should be down and many of our U.S. customers have already announced reduced capital budgets in 2009. Consensus in the industry is that the U.S. will experience a decline of 300 to 500 rigs from peak levels over the first six months of the fiscal year. Comparable percentage activity reduction should occur over the course of the year in the Canadian market. The international markets should experience less activity reduction as many of the international projects are based on longer-term commitments. However, in the event crude oil and natural gas prices decline significantly from current price levels, drilling activity could experience significant reductions from our expectations for the year. Our capital spending for the year is planned to be lower than the prior year, with more emphasis on the international markets and the Oilfield Services Group where we expect better growth opportunities over the next few years.

With our strong and experienced team of more than 18,000 employees, our global presence and reputation for meeting customer needs, and our commitment to training, safety, technology and employee development, I am confident that the Company will manage through what may be a more difficult industry environment in fiscal 2009. We look forward to the challenges and opportunities that lie ahead.



J.W. Stewart
Chairman, President and CEO



Corporate Officers

BJ Services Company Officers, November 2008
(Front row, L-R),
J.W. Stewart,
Chairman of the Board, President and Chief Executive Officer.
Margaret B. Shannon, Vice President – General Counsel.
Susan Hill, Vice President – Human Resources.
L. Scott Biar, Vice President – Controller.
(Second row)
Jeff Hibbeler, Vice President – Technology and Logistics.
Ronald F. Coleman, Vice President – North America Pressure Pumping Services.
(Third row)
Alasdair Buchanan, Vice President – International Pressure Pumping Services.
Paul Yust, Vice President – Chief Information Officer.
Jeffrey E. Smith, Executive Vice President – Finance and Chief Financial Officer.
Bret Wells, Vice President– Treasurer and Chief Tax Officer.
David Dunlap, Executive Vice President and Chief Operating Officer.

Board of Directors

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

John R. Huff‡
Chairman of Oceaneering International, Inc.

Don D. Jordan*‡
Former Chairman 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 Company, Inc.

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

William H. White‡#
Mayor of the 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

SEC Mail Processing Section

DEC 29 2008

Washington, DC 111

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, 2008

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, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑	Accelerated filer ☐
Non-accelerated filer ☐	Smaller reporting company ☐

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

At November 17, 2008, the registrant had outstanding 291,930,997 shares of Common Stock, $.10 par value per share. The aggregate market value of the Common Stock on March 31, 2008 (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 $8.4 billion.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the registrant's Proxy Statement for the Annual Meeting of Stockholders to be held January 29, 2009 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 casing and tubular services; precommissioning, maintenance and turnaround services in the pipeline and process business, including pipeline inspection; chemical services; completion tools; and completion fluids.

During the year ended September 30, 2008, we generated approximately 81% of our revenue from pressure pumping services and 19% from the oilfield services group. Over the same period, we generated approximately 57% of our revenue from United States operations and 43% from international operations. For segment and geographic information for each of the three years ended September 30, 2008, see Note 8 of the Notes to 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.
- **Canada Pressure Pumping Services.** This segment includes pressure pumping services derived from our activities in Canada.
- **International Pressure Pumping Services.** This segment includes pressure pumping services derived from our activities outside of the United States, Mexico and 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 include 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 2008, 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 string 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 2008, 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 has increased in recent years, the demand for fracturing and other stimulation services has also increased. 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 United States 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 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 2008, approximately 17% of our U.S. fleet remained as candidates for future replacement as part of our recapitalization initiative.

The proliferation of activity in areas of gas bearing shale formation production in North Texas, Arkansas, Oklahoma, North Louisiana, Pennsylvania, West Virginia, and British Columbia has created increased market demand for fracturing assets. Gas shale formations require as much as 30,000 horsepower, nearly three times the horsepower requirement of the average North American fracturing treatment. Much of the equipment that is being added to our North American fleet is in response to the increased activity in these gas shale markets.

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, Ecuador, West Africa, China, Indonesia, India, Saudi Arabia and Malaysia. Our completion tools and completion fluids, 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. 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 a skid-mounted reel 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 19% of our total revenue in fiscal 2008. This segment consists of casing and tubular services, process and pipeline services, chemical services, completion tools and completion fluids services in the United States 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. 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 uses electromagnetic-based instruments to monitor metal loss from the interior pipe wall caused by either corrosion or mechanical damage. A second set of tools monitors pipeline geometry (dents, buckles and wrinkles) and position (latitude, longitude, and height) using an inertial guidance system, which allows the production of as-built maps of the pipeline, as well as the calculation of critical strains due to pipeline movement. Using the information collected by these tools, pipeline operators are able to prepare structural analysis to determine if the pipeline is fit for its purpose.

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. Chemical services also provides the equipment and services associated with installation of capillary tubing in oil and gas wells. Capillary tubing is normally steel or other alloy pipe, manufactured in continuous sections of less than one inch diameter. The tubing is installed into a live wellbore and used to convey production chemicals to predetermined depth locations in a wellbore. Positioning the injection point of chemicals within a wellbore optimizes the effectiveness of the chemical treatment. These services are carried out with purpose-built equipment and are most often utilized in low-pressure gas wells for foamer injection associated with de-liquefaction. 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) de-liquefaction 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) 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. Our tools 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, Ecuador, West Africa, China, Indonesia, India, Saudi Arabia and Malaysia.

As a result of the acquisition of Innicor Subsurface Technologies Inc. in May of 2008, we began offering tool services, shaped charges and perforating guns.

Tool services includes a broad array of downhole equipment and services related to the drilling, completion and production enhancement operations in oil and gas wells. The equipment includes open hole packers, retrievable completion packers, seal bore packers, service tools, tubing anchors, liner hanger equipment, flow control equipment, bridge plugs and retainers. Tool services can be provided on a stand-alone basis or combined with elements of a pressure pumping services operation.

Tool services are normally contracted by an oil and gas company to provide equipment during the drilling or completion operations. The equipment is delivered to a well site and then a tool specialist remains on the well location as the equipment is installed in the well. The equipment includes saleable items that are permanently installed in oil and gas wells as well as rental equipment which is run into a wellbore on a temporary basis and then retrieved at the conclusion of an operation. These rental items are then "redressed" and prepared for application in other wells. We have a specialty manufacturing plant in Calgary, which produces components required for the equipment. In addition, outside machine shops are used for some component manufacturing and assembly.

Innicor Perforating Systems, a wholly owned subsidiary, is a provider of shaped charges and perforating guns for use by service companies involved in either wireline or tubing-conveyed perforating operations. Perforating is a process in which explosive charges are used to create holes in a cased wellbore. These holes are the primary method of communicating the reservoir gas and/or fluids from the formation into the wellbore. This operation can either be conducted during the initial completion of a well or as a subsequent remedial operation.

We have an explosive charge manufacturing plant in Standard, Alberta where the shaped charges are produced. The perforating guns, which are used to transport shaped charges into a wellbore, are manufactured in Calgary.

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. We also provide 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 United States and Brazil. Sufficient material inventories are generally maintained to allow us to provide on-call services to our pressure pumping customers. We continue to experience intermittent tightness in supply for certain types of fracturing proppants but have been able to use alternatives with customer acceptance, and this constraint is not expected to materially hinder operations. In addition, we have entered into agreements to ensure certain levels of materials are maintained in the United States 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 coiled tubing, we have not experienced any difficulty in obtaining coiled tubing in the past and do not anticipate difficulty in the foreseeable future.

Raw steel and other alloys are commonly utilized in our completion tools business to machine components for these specialty downhole tools. Numerous suppliers exist for these materials and we do not anticipate any difficulty in sourcing these materials in the foreseeable future.

Nitrogen is one of the principal materials used in our process and pipeline services division and our pumping services operations. 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: Equipment Software, Instrumentation Engineering, Mechanical Engineering, Coiled Tubing Engineering and Completion Tools Engineering.

Equipment Software

Our equipment software group develops and supports a wide range of proprietary software used to monitor both cementing 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. 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 our pressure pumping services operations. 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 for these services. In addition, to the manufacturing facilities mentioned above, we also have the following:

- a manufacturing facility in Calgary, Alberta that produces equipment for our tools services and Innicor Perforating Systems operations within the completion tools business;
- a shaped charge manufacturing plant in Standard, Alberta that produces shaped charge explosives for our perforating guns within the completion tools business;
- a facility in Lafayette, Louisiana that assembles downhole completion tools for our completion tools business;
- a calcium chloride manufacturing plant in Geismer, Louisiana that creates liquid calcium chloride through a reaction process for use in our completion fluids business;
- a chemical blending facility in Hobbs, New Mexico that produces chemicals for use in chemical services and pressure pumping services.

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 and are larger in terms of overall pressure pumping revenue. We also compete with Weatherford International Ltd. and numerous smaller companies including Calfrac Well Services Ltd., Trican Well Service Ltd., San Antonio, Superior Well Services and Frac Tech Services, Ltd. During 2007 and 2008, we have experienced increased competition in the U.S. and Canadian markets from these and other new competitors. Competitive factors impacting our business are price, 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. We 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 Ltd. 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, including Baker PetroLite (a division of Baker Hughes Incorporated), Champion Technologies, Nalco Energy Services and Clariant.

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

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

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 in the Canadian market.

Our principal customers consist of major and independent oil and natural gas producing companies, as well as national oil companies. During fiscal 2008, 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 United States, a majority of which offer both cementing and stimulation services. As the result of the increased activity in the U.S. gas shale markets, we opened a new facility in Searcy, Arkansas during fiscal 2008. Demand for our pressure pumping services in the United States 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 1,851 in fiscal 2008, a 6% increase over the fiscal 2007 average U.S. rig count of 1,749. In fiscal 2007, the average U.S. rig count was 10% higher than the fiscal 2006 U.S. rig count average of 1,587.

Canada

The Canadian market is very similar to the United States 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. In fiscal 2007, the average rig count was 365, 27% lower than the fiscal 2006 rig count average. Fiscal 2008 average annual rig count was 366, slightly higher than the fiscal 2007 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 economic hedges.

International

We operate in approximately 50 countries which encompass the major international oil and natural gas producing areas of Latin America, Europe, Africa, the Middle East, Asia Pacific and Russia. We generally provide services to international customers through wholly-owned foreign subsidiaries. Additionally, we hold controlling 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, excluding Canada and including Mexico, averaged 616 in fiscal 1999 and the highest international rig count averaged 1,061 in fiscal 2008, a 7% increase over the fiscal 2007 average international rig count of 989. In fiscal 2007, the average international rig count was 9% higher than the fiscal 2006 international rig count average of 905.

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.

Employees

At September 30, 2008, we employed approximately 18,000 personnel around the world. Approximately 60% of our employees are employed outside the United States. As we experience expanding activity levels in certain markets, we have encountered intermittent labor shortages. We continue to focus on hiring and retaining qualified operations personnel as well as accommodate for temporary labor 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 disposal of empty chemical drums, improvement to acid and wastewater handling facilities, and cleaning certain areas at our facilities located both domestically and internationally. We also have procedures for the operation of underground storage tanks in the United States. In addition, we maintain insurance for certain environmental liabilities, which we believe is reasonable based on our experience and knowledge of the industry.

In the United States, the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), 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 five 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 the United States. 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, 2008, see Note 12 of the Notes to Consolidated Financial Statements.

Some of our key patented and patent pending technologies include:

(1) fracturing fluids, such as our high-performance SPECTRAFRAC G® and QUADRAFRAC™, and low-polymer loading VISTAR® fluid;

(2) our LITEPROP® 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) 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;

(7) polymer-specific enzyme fluid breakers and EZ CLEAN®, a polymer-specific enzyme treatment designed to remediate reservoirs that have been damaged by previous fracturing efforts;

(8) production chemicals ICE-CHEK™ and SCALESORB™, which inhibit gas hydrates in extreme cold conditions and control scale, respectively, in the well;

(9) the TEKTOTE® delivery system for the safe and efficient transportation and handling of our TEKPLUG® cross-linked fluid loss systems;

(10) FLEXSAND™ deformable additives to control proppant flowback, while maintaining fracture conductivity; and

(11) the MST (multi-zone, single-trip) completion system, which eliminates several operational steps compared to traditional multi-zone frac pack/gravel pack completions, resulting in reduced cost and less nonproduction time.

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 Securities Exchange Act of 1934 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	64	Chairman of the Board, President and Chief Executive Officer	1990
David Dunlap	47	Executive Vice President—Chief Operating Officer	2007
Jeffrey E. Smith	46	Senior Vice President—Finance and Chief Financial Officer	2006
Ronald F. Coleman	54	Vice President—North America Pressure Pumping Services	2007
Alasdair Buchanan	48	Vice President—International Pressure Pumping Services	2007
Margaret B. Shannon	59	Vice President—General Counsel	1994
L. Scott Biar	45	Vice President—Controller	2007
Susan Douget	48	Vice President—Human Resources	2003
Jeff Hibbeler	43	Vice President—Technology and Logistics	2007
Bret Wells	43	Vice President—Treasurer and Chief Tax Officer	2006
Paul Yust	55	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. 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. 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. Coleman joined the Company in 1977 and was named Vice President—North American Pressure Pumping Services in 2007. Prior to being promoted to Vice President—North American 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.

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 of our International Pressure Pumping business, a position he held from 1999 through 2005.

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. Biar joined the Company as Vice President—Controller in December 2007. Prior to joining the Company, Mr. Biar was employed by Stewart & Stevenson Services, Inc. from 2002 through 2007, where he served as Vice President, Controller and Chief Accounting Officer from December 2002 through January 2006 and Chief Financial Officer, Treasurer and Controller from January 2006 until May 2006, when the company was sold to Armor Holdings, Inc. Mr. Biar remained with Stewart & Stevenson in a transitional financial and consulting role from May 2006 through August 2007. Mr. Biar is a Certified Public Accountant.

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. 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 the Asia Pacific Region of our International Pressure Pumping business. Prior to that, he held the position of Country Manager for several countries in Asia Pacific and Latin America.

Mr. Wells joined the Company as Tax Director in 2002. Prior to that, 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:

- general global economic and business 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,
- our ability to attract and retain skilled, trained personnel to provide technical services and support for our business,
- our ability to procure sufficient supplies of materials essential to our business, such as cement, proppants (including sand), certain chemicals, and specialty metals,
- the business opportunities that may be presented to and pursued by us,
- competition in our business, including the addition of new competitors and new capacity in North America,
- consolidation by our customers, which could result in loss of a customer, and
- changes in laws or regulations and other factors, many of which are beyond our control.

Risks from an Economic Downturn and Lower Oil and Natural Gas Prices

Recent economic data indicate that the rate of economic growth in the United States and worldwide has declined significantly from the growth rates experienced in recent years. Prolonged periods of little or no economic growth will likely decrease demand for oil and natural gas, which could result in lower prices for crude oil and natural gas and therefore lower demand and potentially lower pricing for our products and services. If economic conditions deteriorate for prolonged periods, our results of operations and cash flows could be adversely affected. Crude oil and natural gas prices have declined significantly from their historic highs in July 2008, and such price declines can be expected to reduce drilling activity and demand for our services from the levels experienced during fiscal 2008. In addition, most of our customers are involved in the energy industry, and if a significant number of them experience a prolonged business decline or disruption as a result of economic slowdown or lower crude oil and natural gas prices, we may incur increased exposure to credit risk and bad debts.

Risks related to the Worldwide Oil and Natural Gas Industry

Conditions in the oil and natural gas industry are subject to factors beyond our control. Demand for our products and services is dependent upon the level of oil and natural gas exploration and development activities around the world. The level of worldwide oil and natural gas development activities is primarily influenced by the price of crude oil and natural gas, as well as expectations about future crude oil and natural gas prices. Crude oil and natural gas prices have been extremely volatile in recent months, and have declined significantly from their historic highs in July 2008. Such price declines can be expected to reduce drilling activity and demand for our services from the levels experienced during fiscal 2008 which could lead to lower pricing for our products and services. Prolonged periods of historically lower drilling activity could have a materially adverse impact on our financial condition, results of operations and cash flows.

Risks related to Global Credit Crisis

Recent events in the global credit markets have significantly impacted the availability of credit and financing costs for many of our customers. Many of our customers finance their drilling and production programs through third-party lenders. The reduced availability and increased costs of borrowing could cause our customers to reduce their spending on drilling programs, thereby reducing demand and potentially resulting in lower pricing for our products and services. Also, the current credit and economic environment could significantly impact the financial condition of some customers over a period of time, leading to business disruptions and restricting their ability to pay us for services performed, which could negatively impact our results of operations and cash flows.

In addition, an increasing number of financial institutions and insurance companies have reported significant deterioration in their financial condition. Our forward-looking statements assume that our lenders, insurers and other financial institutions will be able to fulfill their obligations under our various credit agreements, insurance policies and contracts. If any of our significant financial institutions were unable to perform under such agreements, and if we were unable to find suitable replacements at a reasonable cost, our results of operations, liquidity and cash flows could be adversely impacted.

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 businesses, during work performed on oil and natural gas wells,
- in the chemical services business, as a result of use of our products in oil and natural gas wells and refineries, and
- in the process and pipeline business, as a result of work performed by us at petrochemical plants and 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 market conditions and our claims history 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 ("DOJ"), the 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 have had discussions with the DOJ 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 DOJ, the SEC or other authorities or the effect the actions may have on our business or consolidated financial statements. For further information regarding our investigations, see Note 12 of the Notes to 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 risk that 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, which 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.

Greenhouse Gases

A variety of regulatory developments, proposals or requirements have been introduced in the domestic and international regions in which we operate that are focused on restricting the emission of carbon dioxide, methane and other greenhouse gases. Among these developments are the United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol" (an internationally applied protocol, which has been ratified in Canada, one of our reporting segments), the Regional Greenhouse Gas Initiative or "RGGI" in the Northeastern United States, and the Western Regional Climate Action Initiative in the Western United States. Also, in 2007, the U.S. Supreme Court held in Massachusetts, et al. v. EPA that greenhouse gases are an "air pollutant" under the federal Clean Air Act and thus subject to future regulation. These developments may curtail production and demand for fossil fuels such as oil and gas in areas of the world where our customers operate and thus adversely affect future demand for our products and services, which may in turn adversely affect our future results of operations.

Other Risks

Other risk factors could cause actual results to be different from the results we expect. The market price for our common stock, as well as other companies in the oil and natural gas industry, has been historically volatile, which could restrict our access to capital markets in the future. Other risks and uncertainties may be detailed from time to time in our filings with the Securities and Exchange Commission.

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. Forward-looking statements speak only as of the date they are made and except as required by applicable law, we do not assume any responsibility to update or revise 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 "Business—Raw Materials and Equipment".

In addition, we own or lease the following manufacturing facilities:

Location	Owned/Leased	Description
Tomball, Texas	Owned	Research and technology center housing our main equipment and instrumentation manufacturing operation, primarily serving pressure pumping services
Calgary, Alberta	Owned	Additional manufacturing to support our global pressure pumping manufacturing needs
Singapore	Owned	Additional manufacturing to support our global pressure pumping manufacturing needs
Houston, Texas	Owned	Produces certain components and spare parts required for the assembly of downhole completion tools, services tools, and well screens
Lafayette, Louisiana	Owned	Assembly of downhole completion tools and administrative offices related to completion tools
Calgary, Alberta	Leased	Manufactures and assembles downhole service tools for our completion tools business
Standard, Alberta	Owned	Manufactures shaped charges included in our downhole tools product offering
Geismer, Louisiana	Owned	Creates liquid calcium chloride through a reaction process for use in our completion fluids business
Hobbs, New Mexico	Owned	Produces chemicals for use in chemical services and pressure pumping services

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 Consolidated Financial Statements), most 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 Consolidated Financial Statements.

ITEM 3. Legal Proceedings

The information regarding litigation and environmental matters described in Note 10 of the Notes to 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, 2008.

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 17, 2008, there were approximately 1,279 holders of record of our common stock.

The table below sets forth for the periods indicated the high and low sales prices per share of our common stock reported on the NYSE composite tape.

	Common Stock Price Range	
	High	**Low**
Fiscal 2008		
1st Quarter	$28.79	$23.12
2nd Quarter	29.00	19.30
3rd Quarter	33.66	26.93
4th Quarter	34.94	18.12
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

At September 30, 2008, there were 347,510,648 shares of common stock issued and 294,231,626 shares outstanding. Our authorized number of shares of common stock is 910,000,000 shares. The closing sale price per share of our common stock on November 17, 2008 was $10.90.

Stock Repurchases

In 1997, our Board of Directors initiated a stock repurchase program, which through a series of increases, authorizes the repurchase of up to $2.2 billion of Company stock. Repurchases are made at the discretion of management and the program will remain in effect until terminated by our Board of Directors. We purchased 84,073,882 shares at a cost of $1,730.7 million through fiscal 2006. During fiscal 2007, we purchased a total of 2,564,457 shares at a cost of $74.6 million. During fiscal 2008, we purchased a total of 101,400 shares at a cost of $2.1 million. From October 1, 2008 through November 17, 2008, we have purchased 3,466,500 shares at a cost of $44.2 million. We currently have remaining authorization to purchase up to an additional $348.4 million in stock.

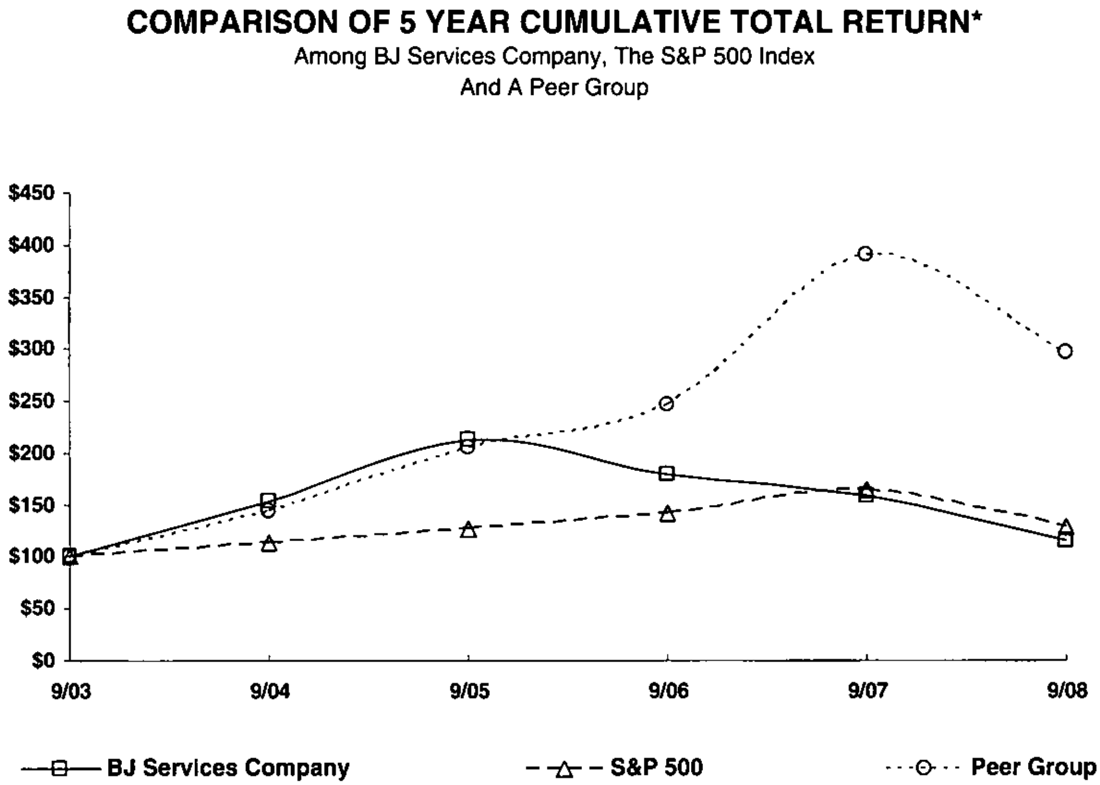
Dividend Program

We have paid cash dividends in the amount of $.05 per common share each quarter since the fourth quarter of fiscal 2005. We anticipate paying cash dividends in the amount of $.05 per common share on a quarterly basis in fiscal 2009. 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 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.



* $100 invested on 9/30/03 in stock & index-including reinvestment of dividends.
Fiscal year ending September 30.

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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, 2008 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,				
	2008	2007	2006	2005	2004
	(in thousands, except per share amounts)				
Operating Data:					
Revenue	$ 5,426,262	$ 4,802,409	$ 4,367,864	$ 3,243,186	$ 2,600,986
Operating expenses	(4,519,165)	(3,651,870)	(3,196,128)	(2,606,127)	(2,162,601)
Operating income	907,097	1,150,539	1,171,736	637,059	438,385
Interest expense	(28,112)	(32,731)	(14,558)	(10,951)	(16,389)
Interest income	1,912	1,624	14,916	11,281	6,073
Other income (expense), net[(1)]	(12,751)	(6,584)	(11)	15,958	92,668
Income tax expense	(258,781)	(359,208)	(367,473)	(200,305)	(159,696)
Net income	609,365	753,640	804,610	453,042	361,041
Earnings per share[(2)]:					
Basic	2.08	2.57	2.55	1.40	1.13
Diluted	2.06	2.55	2.52	1.38	1.10
Depreciation and amortization	269,121	211,262	167,445	137,321	125,982
Capital expenditures[(3)]	606,866	752,113	459,974	323,763	200,577
Financial Position Data (at end of period):					
Property, net	$ 2,312,949	$ 1,965,719	$ 1,392,926	$ 1,086,932	$ 913,713
Total assets	5,321,908	4,715,212	3,862,288	3,409,642	3,301,330
Long-term debt and capital leases, excluding current maturities	506,220	252,709	500,140	455	78,936
Stockholders' equity	3,441,807	2,851,398	2,146,940	2,492,041	2,102,424
Cash dividends declared per common share	.20	.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. Fiscal 2005 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.

(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 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, Canada Pressure Pumping, International Pressure Pumping and the Oilfield Services Group.

The U.S./Mexico, Canada and International 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 casing and tubular services, process and pipeline services, chemical services, completion tools and completion fluids services in the United States 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 and the volatility and expectations of future oil and natural gas prices. Our results of operations also depend heavily on the pricing we receive from our customers, which depends on activity levels, availability of equipment and other resources, and competitive pressures. 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 our fiscal years ended September 30:

	2008	% Change	2007	% Change	2006
Worldwide Rig Count[1]:					
U.S.	1,851	6%	1,749	10%	1,587
Canada	366	0%	365	-27%	502
International[2]	1,061	7%	989	9%	905
Commodity Prices (average):					
Crude Oil (West Texas Intermediate)	$107.64	67%	$64.62	-2%	$66.06
Natural Gas (Henry Hub)	$ 9.00	30%	$ 6.90	-15%	$ 8.16

(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 100, 90 and 85 for the fiscal years ended September 30, 2008, 2007 and 2006 respectively.

Oil and natural gas prices have been extremely volatile in recent months, and have declined significantly from their historic highs in July 2008. Crude oil (West Texas Intermediate) and Natural Gas (Henry Hub) prices at November 17, 2008, were $54.95 and $6.55, respectively.

U.S. Rig Count

Demand for our pressure pumping services in the United States 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 1,851 in fiscal 2008.

With the retraction of oil and natural gas prices over the last few months along with uncertainty in the credit markets, we expect to see some reduction in North America drilling activity in 2009. The magnitude of reduction is uncertain, and will ultimately be influenced by a number of factors, including commodity prices, winter demand for oil and natural gas and government policy with respect to the financial credit crisis.

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 United States, 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.

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 1,061 in fiscal 2008.

Results of Operations

Consolidated (dollars in millions)

	2008	% Change	2007	% Change	2006
Revenue	$5,426.3	13%	$4,802.4	10%	$4,367.9
Operating income	907.1	-21%	1,150.5	-2%	1,171.7
Worldwide rig count[1]	3,278	6%	3,103	4%	2,995

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

Results for fiscal 2008 compared to fiscal 2007

Consolidated revenue for fiscal 2008 increased 13% compared to fiscal 2007, with all of our reportable segments showing revenue growth. Revenue from U.S./Mexico Pressure Pumping Services increased 8% from last year as a result of higher activity levels largely offset by lower pricing for our products and services. Revenue from our Canada and International Pressure Pumping Services increased 14% and 17%, respectively. The Canadian increase was primarily attributable to favorable exchange rates and the International increase was the result of increased activity in the Middle East, Asia Pacific and Latin America. During 2008, our Oilfield Services Group's revenue increased 23%, largely as a result of increased international activity and, to a lesser extent, the acquisition of Innicor Subsurface Technologies Inc. in May 2008.

Despite improved revenue from all of our reportable segments, consolidated operating income margin declined from 24% in fiscal 2007 to 17% in fiscal 2008. Declining prices for our products and services in the North American market as well increased material and fuel costs led to the overall decline in operating income margin.

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 margin was 24%, down from 27% in 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.

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

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

	2008	% Change	2007	% Change	2006
Revenue	$2,777.6	8%	$2,562.7	9%	$2,353.8
Operating income	605.6	-31%	881.6	-2%	899.2
U.S. rig count[1]	1,851	6%	1,749	10%	1,587
Mexico rig count[1]	100	11%	90	6%	85

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

Results for fiscal 2008 compared to fiscal 2007

Fiscal 2008 revenue for our U.S./Mexico Pressure Pumping segment increased 8% compared the prior fiscal year, with average active drilling rigs increasing 6%. All of the operating regions within U.S./Mexico Pressure Pumping, except the Gulf Coast, showed improved revenue from fiscal 2007. While U.S. activity increased for fiscal 2008 compared to fiscal 2007, the prices we received for our products and services declined.

U.S./Mexico Pressure Pumping operating income margin decreased from 34% in fiscal 2007 to 22% for fiscal 2008. A decline in prices coupled with increased material, maintenance and fuel costs caused the fiscal 2008 decline.

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.

Canada Pressure Pumping (dollars in millions)

	2008	% Change	2007	% Change	2006
Revenue	$442.5	14%	$386.5	-20%	$481.4
Operating income	34.3	6%	32.5	-68%	102.1
Canada rig count(1)	366	0%	365	-27%	502

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

Results for fiscal 2008 compared to fiscal 2007

The 14% increase in revenue for Canada Pressure Pumping for fiscal 2008 is almost entirely due to the strengthening of the Canadian dollar. Relative to the U.S. dollar, the average Canadian dollar exchange rate increased 9% in fiscal 2008 compared to fiscal 2007, thereby increasing the U.S. dollar equivalent of revenues earned in Canada. Activity levels had little impact on the revenue increase, as the Canadian average active drilling rigs for fiscal 2008 remained unchanged from the prior year.

Operating income margin for fiscal 2008 was 8%, consistent with fiscal 2007. Despite improved revenues, the region operating income margin was negatively impacted by increased pricing pressures and cost increases in fiscal 2008.

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.

International Pressure Pumping Segment (dollars in millions)

	2008	% Change	2007	% Change	2006
Revenue	$1,252.6	17%	$1,074.7	21%	$884.7
Operating income	172.5	13%	152.7	11%	138.1
International rig count, excluding Mexico(1)	961	7%	899	10%	820

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

Results for fiscal 2008 compared to fiscal 2007

	% change in Revenue
Europe (1)	-11%
Middle East (1)	27%
Asia Pacific	15%
Latin America (1)	28%
Russia	-7%

(1) In fiscal 2008, we revised the internal management reporting structure of our pressure pumping operations in Africa, whose results of operations were previously reported in our Europe/Africa operating segment. Our North Africa results, including Algeria and Libya, are now included in our Middle East operating segment, while our West Africa results south of Nigeria, including Angola and Gabon, are now included in our Latin America operating segment. Nigeria and coastal areas north of there remain as part of our Europe operating segment. Prior period results have been revised to conform with the current presentation.

International Pressure Pumping revenue increased 17% for fiscal 2008 compared fiscal 2007. Increased revenue from our Middle East and Latin American operations were significant contributors to the overall revenue increase. Our Middle East operations benefited from the introduction of two stimulation vessels into the India market as well as improved revenues from Algeria and activity increases in Saudi Arabia, Kazakhstan and Azerbaijan.

Our Latin American operations experienced significant growth in Brazil, Argentina, Gabon and Venezuela when comparing fiscal 2008 revenue to fiscal 2007, primarily as a result of increased drilling and completion activity in those countries. Average active drilling rigs in the region increased 6% when compared to the prior year.

In Asia Pacific, revenue increased 15% with average active drilling rigs in the region increasing 11%. Most major markets within the region experienced revenue growth.

Declines in revenue from our offshore stimulation vessel in the North Sea due to its relocation to India, as well as a revenue decline from our Northern West Africa operations caused the 11% decrease in revenue for Europe for fiscal 2008.

The decline in revenue in Russia was almost entirely due to the sale of the work-over rig business during fiscal 2007.

Operating income margin remained consistent with fiscal 2007 at 14%, with declines in revenue from our Russia and Asia Pacific operations offsetting positive contribution to operating income from our other operating regions.

During fiscal 2008 we recognized a non-cash goodwill impairment charge of $6.1 million related to our Russia operations. With the competitive pressure in the areas in which we operate in Russia, cost inflation, currency risks and concerns over future activity reductions, our analysis indicates that our goodwill associated with Russia might not be recoverable.

Results for fiscal 2007 compared to fiscal 2006

	% change in Revenue
Europe(1)	2%
Middle East(1)	41%
Asia Pacific	28%
Latin America(1)	23%
Russia	-5%

(1) In fiscal 2008, we revised the internal management reporting structure of our pressure pumping operations in Africa, whose results of operations were previously reported in our Europe/Africa operating segment. Our North Africa results, including Algeria and Libya, are now included in our Middle East operating segment, while our West Africa results south of Nigeria, including Angola and Gabon, are now included in our Latin America operating segment. Nigeria and coastal areas north of there remain as part of our Europe operating segment. Prior period results have been revised to conform with the current presentation.

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

Europe showed improvement due to increased activity in the Netherlands. This increase was slightly offset by lower coiled tubing revenue in Norway. The average active drilling rig count in Europe increased 8% compared to fiscal 2006.

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, increased coiled tubing work in Saudi Arabia, the expansion of operations into Libya, and the acquisition of a controlling interest in our Algerian joint venture in July 2006. The average active drilling rig count for fiscal 2007 in the region 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 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.

Our Russian revenue declined as the result of the divesture of our workover rig business in the region during the year as well as lower margin performance activity. Excluding revenue from our workover rig business, revenue from the region increased 10% compared to fiscal 2006.

Operating income margin for International Pressure Pumping was 14% for fiscal 2007 compared to 16% in fiscal 2006. 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.

Oilfield Services Group (in millions)

	2008	% Change	2007	% Change	2006
Revenue	$953.6	23%	$778.4	20%	$648.0
Operating income	183.9	12%	163.5	23%	132.4

Results for fiscal 2008 compared to fiscal 2007

	% Change in Revenue
Tubular Services	11%
Process and Pipeline Services	37%
Chemical Services	31%
Completion Tools	42%
Completion Fluids	-18%

All of the operating segments within our Oilfield Services Group, except Completion Fluids which was negatively impacted by a decline in offshore deepwater activity in the Gulf of Mexico, showed improved revenues for fiscal 2008 compared to the prior year. Process and Pipeline Services benefited from increased international and domestic activity, while Chemical Services benefited primarily from increased revenue from capillary services and increased U.S. activity levels.

In May 2008 we acquired Innicor Subsurface Technologies Inc. This acquisition along with increased activity levels in international markets accounted for our Completion Tools revenue improvement. Excluding the effect of the Innicor acquisition, Completion Tools revenue improved 29%. Tubular Services also showed improved revenue as a result of increased activity in international markets.

Operating income margin for fiscal 2008 declined to 19% from 21% in the prior year. Positive contributions from our Process and Pipeline Services, Chemical Services and Tubular Services groups were offset by declining operating income margins from our other operating segments within the Oilfield Services Group.

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.

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.

With the current commodity price and credit environment, we anticipate that North American drilling activity will be lower in 2009 compared to 2008 which would negatively impact demand for our products and services. The extent and duration of the projected decline is uncertain at this time, but we will continue to focus on labor cost efficiencies and monitor discretionary spending to respond to prevailing activity levels.

Historically, international drilling programs tend to be longer-term in nature, and therefore less affected by short term swings in oil prices. Consequently, we expect to see year over year revenue growth in our International Pressure Pumping operations, based on contracts in place and current prospects. However, in the event crude oil and natural gas prices were to decline significantly from current price levels, drilling activity and consequently our activity could experience significant reductions from our projections. Our Oilfield Services businesses reported solid growth in fiscal 2008 and is expected to continue this growth trend in fiscal 2009, particularly outside of North America as these product lines are further expanded into our established international operations.

Other Expenses

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

	2008	% of Revenue	2007	% of Revenue	2006	% of Revenue
Research and engineering	$ 72.0	1.3%	$ 67.5	1.4%	$ 63.9	1.5%
Marketing	120.9	2.2%	107.4	2.2%	103.3	2.4%
General and administrative	161.0	3.0%	144.0	3.0%	132.0	3.0%

Research and engineering expense: Research and engineering expense increased $4.5 million, or 7%, in fiscal 2008 compared to fiscal 2007, primarily due to increased personnel costs. As a percentage of revenue, research and engineering expense decreased to 1.3% in fiscal 2008 compared to 1.4% in the prior fiscal year.

In fiscal 2007, these expenses increased $3.6 million from 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.

Marketing expense: An increase in personnel costs was the main contributor to the $13.5 million, or 13%, increase in marketing expense from fiscal 2007 to fiscal 2008. As a percentage of revenue, fiscal 2008 marketing expense remained consistent with the prior fiscal year.

For fiscal 2007, these expenses increased 4% when compared to fiscal 2006 as the result of higher commissions in certain markets internationally as well as increased headcount to support market growth.

General and administrative expense: In fiscal 2008 general and administrative expenses increased $17.0 million, or 12%, primarily as a result of increased personnel costs and depreciation expense. As a percentage of revenue, general and administrative expense was 3.0 % in fiscal 2008, consistent with fiscal 2007 and 2006.

For fiscal 2007, these expenses remained consistent as a percent of revenue and increased 9% 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.

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

	2008	2007	2006
Interest expense	$(28.1)	$(32.7)	$(14.6)
Interest income	1.9	1.6	14.9
Other expense, net	(12.8)	(6.6)	(0.0)

Interest Expense and Interest Income: Interest expense decreased $4.6 million in fiscal 2008 primarily as a result of lower average outstanding borrowings comparing the respective periods. Outstanding debt balances decreased from $671.0 million at September 30, 2007 to $556.3 million at September 30, 2008. In fiscal 2007, interest expense increased $18.1 million compared to fiscal 2006 as the result of higher average outstanding debt during the respective periods.

Interest income decreased $13.3 million for fiscal 2007 compared to fiscal 2006 as a result of lower average cash and cash equivalents balance throughout the fiscal year. Fiscal 2008 interest income was consistent with fiscal 2007.

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

	2008	2007	2006
Minority interest	$(11,903)	$(11,315)	$(3,970)
Non-operating net foreign exchange loss	(21)	(88)	(1,800)
(Loss) gain from sale of equity method investments	(2,947)	520	432
Recovery of misappropriated funds	4,000	—	2,791
Goodwill impairment	(6,073)	—	—
Other, net	4,193	4,299	2,536
Other expense, net	$(12,751)	$ (6,584)	$ (11)

The increase in other expense, net for fiscal 2008 compared to fiscal 2007 relates to a $6.1 million non-cash charge to impair goodwill for our Russia operations. We also recorded a $2.9 million loss on the sale of our interest in a Hungarian joint venture operation, and we received a $4.0 million cash settlement in a litigation matter.

The increase in other expense, net for fiscal 2007 consisted primarily of minority interest expense, due to the acquisition of a controlling interest in our Algerian joint venture during the third quarter of fiscal 2006.

For additional information, see Note 12 of the Notes to 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):

	2008	2007	2006
Cash provided by operations	$ 898.8	$ 840.7	$ 832.5
Cash used in investing	(648.1)	(777.9)	(503.2)
Cash used in financing	(153.8)	(98.0)	(593.4)
Effect of exchange rate changes on cash	(4.8)	1.0	—
Change in cash and cash equivalents	$ 92.1	$ (34.2)	$(264.1)

Fiscal 2008

Cash flow from operations of $898.8 million in fiscal 2008 increased $58.1 million, or 7% compared to the $840.7 million of cash provided from operations in fiscal 2007, primarily as a result of lower investment in inventories between the two periods. Net cash flows before changes in operating accounts were $988.7 million in fiscal 2008 compared to $1,029.3 million in fiscal 2007, with the decrease primarily attributable to lower U.S./ Mexico pressure pumping operating income. Changes in operating accounts accounted for $89.9 million of cash usage in fiscal 2008, compared to $188.7 million in fiscal 2007 and $171.6 million in fiscal 2006. This improvement was primarily attributable to the stable inventory levels, compared to significant increases in inventory in fiscal 2007 and 2006. Increased receivables accounted for a $124.9 million use of cash, primarily as a result of increased revenues, particularly internationally.

The cash flow used in investing during the fiscal 2008 was almost entirely due to $606.9 million of purchases of property, plant, and equipment and $57.2 million for the acquisition of businesses, principally Innicor Subsurface Technologies Inc in May 2008.

Cash flows used in financing consisted of $113.7 million, net, in payments of short term borrowings and $58.6 million in dividend payments during fiscal 2008. We also received net proceeds in the amount of $14.2 million from employee stock purchases and stock option exercises during fiscal 2008. Further investing activities during the period included the issuance of 6% Senior Notes due 2018 for $246.9 million in net proceeds in May 2008 and the payment of $250.0 million of Senior Notes in June 2008.

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 from the prior year 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 $220.9 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.

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 also included net proceeds from the issuance of Senior Notes in the amount of $496.8 million. 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.

Liquidity and Capital Resources

Cash flows from operations are expected to be our primary source of liquidity in fiscal 2009. Our sources of liquidity also include cash and cash equivalents of $150.3 million at September 30, 2008 and the available financing facilities listed below (in millions):

Financing Facility	Expiration	Borrowings at September 30, 2008	Available at September 30, 2008
Revolving Credit Facility	August 2012	$ —	$400.0
Committed Credit Facility	May 2009	50.0	—
Discretionary	Various times within the next 12 months	7.6	62.2

On May 19, 2008, we completed a public offering of $250.0 million of 6% Senior Notes due 2018. The net proceeds from the offering of approximately $246.9 million, after deducting underwriting discounts and commissions and expenses, were used to retire $250.0 million in outstanding floating rate Senior Notes, which matured June 1, 2008. As of September 30, 2008, the Company had $249.8 million of the 5.75% Senior Notes due 2011 and $248.9 million of the 6% Senior Notes due 2018 issued and outstanding, net of discount.

Our amended and restated revolving credit facility (the "Revolving Credit Facility") permits borrowings of 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. Depending on the amount of borrowings outstanding under this facility, the interest rate applicable to borrowings generally ranges from 30-40 basis points above LIBOR. 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 $0.2 million, $0.3 million and $0.5 million in fiscal 2008, 2007 and 2006, respectively. 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%, although there were no material fees for fiscal 2008 or 2007. There were no borrowings under the Revolving Credit Facility at September 30, 2008 and $147.0 million outstanding at September 30, 2007.

In May 2008, we entered into a Committed Credit Facility with a commercial bank to finance our acquisition of Innicor Subsurface Technologies Inc. There are no commitment fees required by this facility, and the interest rate is based on market rates on the dates that amounts are borrowed. On September 30, 2008, there were $50.0 million in outstanding borrowings under this credit facility. This facility will expire in May 2009.

In addition to the Revolving Credit Facility and the Committed Credit Facility, we had available $62.2 million of discretionary lines of credit at September 30, 2008, which expire at the bank's discretion. Except for $4.8 million, these discretionary lines are unsecured. 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 $7.6 million and $24.3 million in outstanding borrowings under these lines of credit at September 30, 2008 and 2007, respectively. The weighted average interest rates on short-term borrowings outstanding as of September 30, 2008 and 2007 were 5.23% and 5.40%, 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, Revolving Credit Facility, and Committed 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 $550-575 million in fiscal 2009, compared to $606.9 million in fiscal 2008. The actual amount of fiscal 2009 capital expenditures will depend primarily on maintenance requirements and expansion opportunities and our ability to execute our budgeted capital expenditures.

In fiscal 2009, our minimum pension and postretirement funding requirements are anticipated to be approximately $19.3 million. We contributed $16.8 million during fiscal 2008.

We paid cash dividends in the amount of $.05 per common share on a quarterly basis in fiscal 2008, totaling $58.6 million. We anticipate paying a quarterly dividend in fiscal 2009; 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, 2008, the Company had $249.8 million of 5.75% Senior Notes due 2011, $248.9 million of 6% Senior Notes due 2018 issued and outstanding, net of discount and $50.0 million outstanding on a Committed Credit Facility due May 2009. We expect to repay the Committed Credit Facility when it becomes due with cash on hand or financing available from existing credit facilities or a new facility with the same bank. We expect cash paid for interest expense to be approximately $32.0 million in fiscal 2009.

Contractual Obligations and Off Balance Sheet Transactions

The following table summarizes our contractual obligations and other commercial commitments as of September 30, 2008 (in thousands):

Contractual Obligations	Total	Less than 1 year	1-3 Years	4-5 Years	After 5 Years
Long-term and short-term debt	$ 557,610	$ 57,610	$250,000	$ —	$250,000
Interest on long-term debt and capital leases	188,833	29,875	53,958	30,000	75,000
Capital lease obligations	7,490	4,277	3,195	18	—
Operating leases	172,264	51,689	76,952	32,091	11,532
Equipment financing arrangement(1)	54,932	9,074	45,858	—	—
Purchase obligations(2)	387,064	384,064	3,000	—	—
Purchase commitments(3)	75,505	22,480	33,873	19,152	—
Other long-term liabilities(4)	26,406	20,362	144	96	5,804
Total contractual cash obligations	$1,470,104	$579,431	$466,980	$81,357	$342,336

(1) As discussed below, we have the option, but not the obligation, to purchase the pumping service equipment in this partnership for approximately $46 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 United States 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.

On October 1, 2007, we adopted FIN 48, *Accounting for Uncertainty in Income Taxes* ("FIN 48"), which addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. However, the timing of future cash flows associated with FIN 48 is uncertain and we are unable to make reasonably reliable estimates of the period of cash settlement with the respective taxing authority. Therefore, we excluded $59.2 million of unrecognized tax benefits from our contractual obligations table.

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.

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 $4.2 million and $9.0 million as of September 30, 2008 and September 30, 2007, respectively. The agreement permits substitution of equipment within the partnership as long as the implied fair value of the new property transferred in at the date of substitution equals or exceeds the implied fair value, as defined, of the current property in the partnership that is being replaced. As a result of the substitutions, the deferred gain was reduced by $2.7 million in fiscal 2008 and $0.8 million in fiscal 2007. In 2010, we have the option, but not the obligation, to purchase the pumping service equipment for approximately $46 million. We currently intend 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.

We routinely issue Parent Company Guarantees ("PCGs") in connection with service contracts or performance obligations 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 subsidiaries 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 subsidiaries, 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. We have also issued standby letters of credit 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, 2008 (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	$ 33,127	$ 33,127	$ —	$ —	$ —
Guarantees	235,555	114,652	62,500	47,669	10,734
Total other commercial commitments	$268,682	$147,779	$62,500	$47,669	$10,734

Investigations Regarding Misappropriation and Possible Illegal Payments

We have had discussions with the DOJ and the SEC regarding our internal investigation and certain other matters described in Note 12 of the Notes to 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, the 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". 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 Consolidated Financial Statements. Significant accounting policies are discussed in Note 2 of the Notes to 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 future rig count and pricing trends.

During fiscal 2008 we recognized a goodwill impairment charge of $6.1 million related to our Russia operations. With the competitive pressure in the areas in which we operate in Russia, cost inflation, currency risks and concerns over future activity reductions, our analysis indicates that our goodwill associated with Russia might not be recoverable. See Note 11 of the Notes to Consolidated Financial Statements for more information on goodwill.

Pension and Postretirement Benefit Plans: Pension expense and postretirement benefit obligation are determined in accordance with the provisions of SFAS 87, *Employers' Accounting for Pensions,* and SFAS 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions,* respectively. We determine the annual net periodic pension expense and pension plan liabilities on an annual basis. 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. A 50 basis point decrease in the discount rate we used in fiscal 2008 would have resulted in the recognition of approximately $2.7 million in additional expense.

Long-term rate of return assumptions are based on actuarial review of our asset allocation and average annual returns being earned by similar investments. A 50 basis point reduction in the expected rate of return on assets of our plans would have resulted in the recognition of approximately $0.7 million in additional expense in fiscal 2008.

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.

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. 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 pursuant to the terms of the plan.

In accordance with SFAS 158, any changes in our assumptions or differences between estimated and actual return on plan assets and compensation levels result in unrecognized gain/loss which is recorded as a component of stockholders' equity in accumulated other comprehensive income. Amounts recorded to accumulated other comprehensive income are amortized and recognized in net periodic pension expense in future periods.

In fiscal 2009, we will have a pension and postretirement funding requirement of approximately $19.3 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 a U.S. defined benefit pension plan. Plan assets of approximately $72 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 early fiscal 2009, we will record a non-cash charge of approximately $21.6 million in connection with the settlement. This consists of $5.6 million of prepaid pension cost and $16.0 million of loss currently recognized in accumulated 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 regulatory approval of the settlement is received.

Income Taxes: The effective income tax rates were 29.8%, 32.3% and 31.4% for the years ended September 30, 2008, 2007 and 2006, 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, we consider current tax laws, estimates of future taxable income and available tax planning strategies. This process also involves making forecasts of current and future years' U.S, 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 FIN 48 for fiscal 2008 and under the guidance of SFAS 5 for prior periods.

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. We review 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 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 April 2008, the Financial Accounting Standards Board ("FASB") issued FASB Staff Position 142-3, *Determination of the Useful Life of Intangible Assets* ("FSP 142-3"). FSP 142-3 amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under FASB Statement No. 142, *Goodwill and Other Intangible Assets* ("SFAS 142"). The objective of FSP 142-3 is to improve the consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS 141(R), *Business Combinations*, and other U.S. generally accepted accounting principles. FSP 142-3 is effective for fiscal years beginning after December 15, 2008. We are currently in the process of evaluating the impact of FSP 142-3 on our financial statements.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities*, an amendment of FASB Statement No. 133 ("SFAS 161"). SFAS 161 changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (1) how and why an entity uses derivative instruments, (2) how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations, and (3) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS 161 is effective for fiscal years and interim periods beginning after November 15, 2008. We will be required to adopt SFAS 161 in the second quarter of fiscal 2009. We currently do not have any derivative financial instruments subject to accounting or disclosure under SFAS 133; therefore, we do not expect the adoption of SFAS 161 to affect our consolidated statement of financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* ("SFAS 141(R)"), replacing SFAS No. 141, *Business Combinations* ("SFAS 141"). SFAS 141 (R) retains the fundamental requirements in SFAS 141 that the acquisition method of accounting be used for all business combinations and for an acquirer to be identified for each business combination. SFAS 141(R) defines the acquirer as the entity that obtains control of one or more businesses in the business combination and establishes the acquisition date as the date that the acquirer achieves control. SFAS 141(R) establishes principles and requirements for how the acquirer:

a. Recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree.

b. Recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase.

c. Determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination.

This statement is effective for business combinations occurring on or after the beginning of the first annual reporting period beginning after December 15, 2008. We will adopt SFAS 141(R) on October 1, 2009 for acquisitions beginning on or after this date.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements* ("SFAS 160"), amending ARB 51 to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS 160 requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest. It also requires disclosure, on the face of the consolidated statement of income, of the amounts of consolidated net income attributable to the parent and to the noncontrolling interest and requires that a parent recognize a gain or loss in net income when a subsidiary is deconsolidated. SFAS 160 requires expanded disclosures in the consolidated financial statements that identify and distinguish between the interests of the parent's owners and the interests of the noncontrolling owners of a subsidiary and shall be applied prospectively as of the beginning of the fiscal year in which initially applied, except for the presentation and disclosure requirements. The presentation and disclosure requirements shall be applied retrospectively for all periods presented. SFAS 160 is effective for fiscal years beginning after December 15, 2008. We do not have significant noncontrolling interests in consolidated subsidiaries, and therefore, adoption of this standard is not expected to have a significant impact on our financial statements.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, including an amendment of FASB Statement No. 115 ("SFAS 159"). 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. Consequently, we have adopted SFAS 159 effective October 1, 2008 and will not elect to apply the fair value option.

In September 2006, the FASB issued SFAS No. 157 *Fair Value Measurements* ("SFAS 157"), effective for financial statements issued for fiscal years beginning after November 15, 2007. In February 2008, the FASB issued FASB Staff Position 157-2, delaying the effective date of SFAS 157 for non-financial assets and liabilities to fiscal years beginning after November 15, 2008. 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.

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 but that may not prove to be accurate. These statements are subject to risks and uncertainties, including, but not limited to, general economic and business conditions; global economic growth and activity; oil and natural gas market conditions; political and economic uncertainty; and other risks and uncertainties described elsewhere in this Report, including under "Item 1A. Risk Factors." 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. Forward-looking statements speak only as of the date they are made and except as required under securities laws, we do not assume a duty to update or revise these forward-looking statements.

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, 2008, our combined interest expense to third parties would increase by a total of $15 thousand each month in which such increase continued. At September 30, 2008 and 2007, we had fixed-rate debt outstanding of $498.7 million and $249.8 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 $14.3 million if interest rates were to decline by 10% from their rates at September 30, 2008.

Periodically, we borrow funds which are denominated in foreign currencies, which exposes us to market risk associated with exchange rate movements. There were $7.6 million and $15.4 million borrowings denominated in foreign currencies at September 30, 2008 and 2007, 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, 2008. The expected maturity dates and fair value of our market risk sensitive instruments are stated below (in millions). All items described are stated in U.S. dollars.

	Expected Maturity Dates							Fair Value
	2009	2010	2011	2012	2013	Thereafter	Total	9/30/08
SHORT-TERM BORROWINGS								
Bank borrowings; denominated in foreign currencies—average rate 5.23%	$ 7.6						$ 7.6	$ 7.6
Committed Credit Facility—3.3%	50.0						50.0	50.0
LONG-TERM BORROWINGS								
5.75% Senior Notes due 2011			$249.8				249.8	255.2
6% Senior Notes due 2018						$248.9	248.9	250.3
Total	**$57.6**	**$—**	**$249.8**	**$—**	**$—**	**$248.9**	**$556.3**	**$563.1**

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 United States of America.

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, 2008 as required by the Securities and Exchange Act of 1934 Rule 13a-15(c). In making our 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, 2008.

The effectiveness of our internal control over financial reporting as of September 30, 2008 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 **President and Chief Executive Officer**	**Jeffrey E. Smith** **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:
Houston, Texas

We have audited the internal control over financial reporting of BJ Services Company and subsidiaries (the "Company") as of September 30, 2008, 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, 2008, 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 as of and for the year ended September 30, 2008 of the Company and our report dated November 25, 2008 expressed an unqualified opinion on those consolidated financial statements.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
November 25, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of BJ Services Company:
Houston, Texas

We have audited the accompanying consolidated statements of financial position of BJ Services Company and subsidiaries (the "Company") as of September 30, 2008 and 2007, 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, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of BJ Services Company and subsidiaries at September 30, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2008, in conformity with accounting principles generally accepted in the United States of America.

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, 2008, 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 25, 2008 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
November 25, 2008

BJ SERVICES COMPANY

CONSOLIDATED STATEMENT OF OPERATIONS

	Year Ended September 30,		
	2008	2007	2006
	(in thousands, except per share amounts)		
Revenue	$5,426,262	$4,802,409	$4,367,864
Operating expenses:			
Cost of sales and services	4,161,128	3,332,620	2,895,749
Research and engineering	71,997	67,536	63,875
Marketing	120,903	107,421	103,319
General and administrative	161,027	143,992	132,011
Loss on long-lived assets, net	4,110	301	1,174
Total operating expenses	4,519,165	3,651,870	3,196,128
Operating income	907,097	1,150,539	1,171,736
Interest expense	(28,112)	(32,731)	(14,558)
Interest income	1,912	1,624	14,916
Other expense, net	(12,751)	(6,584)	(11)
Income before income taxes	868,146	1,112,848	1,172,083
Income tax expense	258,781	359,208	367,473
Net income	$ 609,365	$ 753,640	$ 804,610
Earnings per share:			
Basic	$ 2.08	$ 2.57	$ 2.55
Diluted	$ 2.06	$ 2.55	$ 2.52
Weighted average shares outstanding:			
Basic	293,479	292,757	315,022
Diluted	295,766	295,916	318,820
Dividends paid per share	0.20	0.20	0.20

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, 2008	As of September 30, 2007
	(in thousands)	
Current assets:		
Cash and cash equivalents	$ 150,254	$ 58,199
Receivables, less allowance for doubtful accounts: 2008, $22,472; 2007, $20,550	1,151,236	1,022,847
Inventories:		
Products	291,857	226,666
Work-in-progress	22,418	37,460
Parts	193,600	221,811
Total inventories	507,875	485,937
Deferred income taxes	28,097	19,994
Prepaid expenses	83,065	72,033
Other current assets	40,623	44,762
Total current assets	1,961,150	1,703,772
Property:		
Land	44,536	29,180
Buildings and other	409,785	359,735
Machinery and equipment	3,447,936	2,947,473
Total property	3,902,257	3,336,388
Less accumulated depreciation	1,589,308	1,370,669
Property, net	2,312,949	1,965,719
Goodwill	975,451	963,937
Deferred income taxes	20,859	30,471
Investments and other assets	51,499	51,313
Total assets	$5,321,908	$4,715,212

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

BJ SERVICES COMPANY

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

LIABILITIES AND STOCKHOLDERS' EQUITY

	As of September 30, 2008	As of September 30, 2007
	(in thousands, except shares)	
Current liabilities:		
Accounts payable, trade	$ 554,615	$ 530,029
Short-term borrowings	57,610	171,268
Current portion of long-term debt	—	250,000
Accrued employee compensation and benefits	148,451	124,231
Income taxes	42,722	51,829
Taxes other than income	43,827	37,282
Other accrued liabilities	172,995	148,549
Total current liabilities	1,020,220	1,313,188
Long-term debt	498,730	249,760
Deferred income taxes	153,923	95,485
Accrued pension and postretirement benefits	127,065	135,901
Other long-term liabilities	80,163	69,480
Commitments and contingencies		
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 294,231,626 outstanding in 2008; 347,510,648 shares issued and 291,735,636 outstanding in 2007)	34,752	34,752
Capital in excess of par	1,100,977	1,060,115
Retained earnings	3,677,258	3,183,922
Accumulated other comprehensive income	40,559	51,644
Treasury stock, at cost (2008 – 53,279,022 shares; 2007 – 55,775,012 shares)	(1,411,739)	(1,479,035)
Total stockholders' equity	3,441,807	2,851,398
Total liabilities and stockholders' equity	$ 5,321,908	$ 4,715,212

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 Compensation	Retained Earnings	Accumulated Other Comprehensive Income	Total
Balance, October 1, 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
Stock awards	26		(355)	355				—
Stock-based compensation			21,397					21,397
Adoption of SFAS 123(R)			(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							(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
Stock awards	91		(2,435)	2,435				—
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**
Adoption of FIN 48 (Note 7)						(8,115)		(8,115)
Comprehensive income:								
Net income						609,365		
Other comprehensive income, net of tax:								
Cumulative translation adjustments							(16,387)	
Changes in defined benefit and other postretirement plans							5,302	
Comprehensive income								598,280
Dividends declared						(58,741)		(58,741)
Treasury stock purchase	(101)			(2,089)				(2,089)
Reissuance of treasury stock for:								
Stock option plan	1,803			48,304		(46,608)		1,696
Stock purchase plan	648			17,202		(2,565)		14,637
Stock awards	146		(3,879)	3,879				—
Stock-based compensation			30,237					30,237
Tax benefit from exercise of options			14,504					14,504
Balance, September 30, 2008	**294,232**	**$34,752**	**$1,100,977**	**$(1,411,739)**	**$ —**	**$3,677,258**	**$ 40,559**	**$ 3,441,807**

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

BJ SERVICES COMPANY

CONSOLIDATED STATEMENT OF CASH FLOWS

	Year Ended September 30, 2008	2007	2006
		(in thousands)	
Cash flows from operating activities:			
Net income	$ 609,365	$ 753,640	$ 804,610
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	269,121	211,262	167,445
Provision for bad debt	9,606	6,541	5,920
Goodwill impairment	6,073	—	—
Loss on long-lived assets, net	4,110	301	1,174
Loss on sale of joint venture	2,947	—	—
Stock-based compensation expense	30,989	30,626	18,336
Excess tax benefits from stock compensation	(14,699)	(1,812)	(3,419)
Deferred income tax expense	59,318	17,472	6,024
Minority interest expense	11,903	11,315	3,970
Changes in:			
Receivables	(124,851)	(103,896)	(220,940)
Inventories	3,599	(129,387)	(111,189)
Prepaid expenses	(8,737)	(35,950)	(14,712)
Accounts payable, trade	15,692	99,375	105,833
Employee compensation and benefits	24,220	(7,494)	26,763
Current income taxes	(9,229)	(8,561)	34,726
Other current assets	4,886	1,909	(20,561)
Other current liabilities	25,248	22,430	17,612
Other, net	(20,767)	(27,114)	10,862
Net cash provided by operating activities	898,794	840,657	832,454
Cash flows from investing activities:			
Property additions	(606,866)	(752,113)	(459,974)
Proceeds from disposal of assets	15,930	32,143	8,932
Acquisitions of businesses, net of cash acquired	(57,174)	(57,920)	(52,172)
Net cash used in investing activities	(648,110)	(777,890)	(503,214)
Cash flows from financing activities:			
Net proceeds from exercise of stock options and stock purchase plan	14,207	22,388	26,142
Purchase of treasury stock	(2,089)	(74,597)	(1,133,313)
Proceeds from issuance of long-term debt	248,858	—	499,673
Repayment of long-term debt	(250,000)	—	(79,000)
Proceeds from Committed Credit Facility	50,000	—	—
(Repayment) proceeds of short-term borrowings, net	(163,658)	10,994	156,884
Dividends paid to stockholders	(58,617)	(58,630)	(64,338)
Excess tax benefits from stock compensation	14,699	1,812	3,419
Distributions to minority interest partners	(5,231)	—	—
Debt issuance costs	(1,976)	—	(2,824)
Net cash used in financing activities	(153,807)	(98,033)	(593,357)
Effect of exchange rate changes on cash	(4,822)	1,020	54
Increase (decrease) in cash and cash equivalents	92,055	(34,246)	(264,063)
Cash and cash equivalents at beginning of year	58,199	92,445	356,508
Cash and cash equivalents at end of year	$ 150,254	$ 58,199	$ 92,445

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

BJ SERVICES COMPANY

NOTES TO 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 casing and tubular services, process and pipeline services, chemical services, completion tools and completion fluids services.

We consolidate all investments in which we own greater than 50%. 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.

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.

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 $7.0 million, $8.0 million, and $2.0 million for the years ended September 30, 2008, 2007 and 2006, 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.

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 for Segment Information. We performed our annual evaluation as of September 30, 2008 and concluded that our goodwill associated with Russia might not be recoverable. As a result of this analysis, we recorded a $6.1 million impairment of goodwill related to our Russia operations in fiscal 2008. There was no impairment adjustment to our goodwill balance in fiscal 2007 based on our analysis performed at September 30, 2007. Other intangible assets primarily consist of acquired patents and are being amortized on a straight-line basis ranging from 2 to 20 years, with the weighted average amortization period being 10.7 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 also provide for taxes in accordance with FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* ("FIN 48"). FIN 48 addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, the tax benefit from an uncertain tax position is to be recognized when it is more likely than not, based on the technical merits of the position, that the position will be sustained on examination by the taxing authorities. Additionally, the amount of the tax benefit to be recognized is the largest amount of benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods, and financial statement disclosures. We recognize potential penalties and interest related to unrecognized tax benefits as a component of income tax expense.

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. We review our self-insurance accruals on a quarterly basis. We have purchased stop-loss coverage 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.

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 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, ("SFAS 133") 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, 2008 or 2007.

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 performance units. 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. Detriments are recognized as a reduction to capital in excess of par to the extent that there is sufficient capital in excess of par available. To the extent there is not sufficient capital in excess of par available the detriment is recorded as tax expense.

New accounting pronouncements: In April 2008, the Financial Accounting Standards Board ("FASB") issued FASB Staff Position 142-3, *Determination of the Useful Life of Intangible Assets* ("FSP 142-3"). FSP 142-3 amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under FASB Statement No. 142, *Goodwill and Other Intangible Assets* ("SFAS 142"). The objective of FSP 142-3 is to improve the consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS 141(R), *Business Combinations*, and other U.S. generally accepted accounting principles. FSP 142-3 is effective for fiscal years beginning after December 15, 2008. We are currently in the process of evaluating the impact of FSP 142-3 on our financial statements.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133* ("SFAS 161"). SFAS 161 changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (1) how and why an entity uses derivative instruments, (2) how derivative instruments and related hedged items are accounted for under SFAS 133, and its related interpretations, and (3) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS 161 is effective for fiscal years and interim periods beginning after November 15, 2008. We will be required to adopt SFAS 161 in the second quarter of fiscal 2009. We currently do not have any derivative financial instruments subject to accounting or disclosure under SFAS 133; therefore, we do not expect the adoption of SFAS 161 to affect our consolidated statement of financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* ("SFAS 141(R)"), replacing SFAS No. 141, *Business Combinations* ("SFAS 141"). SFAS 141(R) retains the fundamental requirements in SFAS 141 that the acquisition method of accounting be used for all business combinations and for an acquirer to be identified for each business combination. SFAS 141(R) defines the acquirer as the entity that obtains control of one or more businesses in the business combination and establishes the acquisition date as the date that the acquirer achieves control. SFAS 141(R) establishes principles and requirements for how the acquirer:

a. Recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree.

b. Recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase.

c. Determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination.

This statement is effective for business combinations occurring on or after the beginning of the first annual reporting period beginning after December 15, 2008. We will adopt SFAS 141(R) on October 1, 2009 for acquisitions beginning on or after this date.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements* ("SFAS 160"), amending ARB 51 to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS 160 requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest. It also requires disclosure, on the face of the consolidated statement of income, of the amounts of consolidated net income attributable to the parent and to the noncontrolling interest and requires that a parent recognize a gain or loss in net income when a subsidiary is deconsolidated. SFAS 160 requires expanded disclosures in the consolidated financial statements that identify and distinguish between the interests of the parent's owners and the interests of the noncontrolling owners of a subsidiary and shall be applied prospectively as of the beginning of the fiscal year in which initially applied, except for the presentation and disclosure requirements. The presentation and disclosure requirements shall be applied retrospectively for all periods presented. SFAS 160 is effective for fiscal years beginning after December 15, 2008. We do not have significant noncontrolling interests in consolidated subsidiaries, and therefore, adoption of this standard is not expected to have a significant impact on our financial statements.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, including an amendment of FASB Statement No. 115 ("SFAS 159"). 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. Consequently, we have adopted SFAS 159 effective October 1, 2008 and will not elect to apply the fair value option.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* ("SFAS 157"), effective for financial statements issued for fiscal years beginning after November 15, 2007. In February 2008, the FASB issued FASB Staff Position 157-2, delaying the effective date of SFAS 157 for non-financial assets and liabilities to fiscal years beginning after November 15, 2008. 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.

3. Acquisitions of Businesses

Fiscal 2008

On May 21, 2008, we acquired all of the outstanding shares of Innicor Subsurface Technologies Inc. ("Innicor") for a purchase price of $54.4 million, including transaction costs, which resulted in an increase of $38.1 million in total current assets, $14.5 million in property and equipment, $0.7 million in intangible assets, $11.2 million in current liabilities, $3.1 million in long term liabilities and $15.4 million of goodwill. Innicor designs, manufactures and provides tools and equipment utilized in the completion and production phases of oil and gas well development in Canada and select international markets. This business complements our completion tools business in the Oilfield Services Group. Pro forma financial information for this acquisition is not included as it is not material to our financial statements.

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 United States 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.

Pro forma financial information for our fiscal 2008 and fiscal 2007 acquisitions is not included as they were not material individually or in aggregate to our financial statements.

4. Earnings Per Share

Basic earnings per share excludes dilution and is computed by dividing net income by the weighted-average number of common shares outstanding for the period. Diluted earnings per share 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, bonus stock 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 each of the three years in the period ended September 30, 2008 (in thousands, except per share amounts):

	2008	2007	2006
Net Income	$609,365	$753,640	$804,610
Weighted-average common shares outstanding	293,479	292,757	315,022
Basic earnings per share	$ 2.08	$ 2.57	$ 2.55
Weighted-average common and dilutive potential common shares outstanding:			
Weighted-average common shares outstanding	293,479	292,757	315,022
Assumed exercise of dilutive instruments	2,287	3,159	3,798
Weighted-average dilutive shares outstanding	295,766	295,916	318,820
Diluted earnings per share	$ 2.06	$ 2.55	$ 2.52

For the years ended September 30, 2008 and 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 for the year ended September 30, 2006, as all outstanding stock options were dilutive in that year.

5. Debt

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

	2008	2007
6% Senior Notes due 2018, net of discount	$248,905	$ —
5.75% Senior Notes due 2011, net of discount	249,825	249,760
Floating rate Senior Notes due 2008	—	250,000
	498,730	499,760
Less current maturities of long-term debt	—	250,000
Long-term debt	$498,730	$249,760

On May 19, 2008, we completed a public offering of $250.0 million of 6% Senior Notes due 2018. The net proceeds from the offering of approximately $246.9 million, after deducting underwriting discounts and commissions and expenses, were used to retire $250.0 million in outstanding floating rate Senior Notes, which matured June 1, 2008. As of September 30, 2008, the Company had $249.8 million of the 5.75% Senior Notes due 2011 and $248.9 million of the 6% Senior Notes due 2018 issued and outstanding, net of discount.

Our amended and restated revolving credit facility (the "Revolving Credit Facility") permits borrowings of 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. Depending on the amount of borrowings outstanding under this facility, the interest rate applicable to borrowings generally ranges from 30-40 basis points above LIBOR. 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 $0.2 million in fiscal 2008 and $0.3 million in fiscal 2007. 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%, although there were no material fees for the fiscal 2008. There were no borrowings under the Revolving Credit Facility at September 30, 2008 and $147.0 million outstanding at September 30, 2007.

In May 2008, we entered into a Committed Credit Facility with a commercial bank to finance our acquisition of Innicor Subsurface Technologies Inc. There are no commitment fees required by this facility, and the interest rate is based on market rates on the dates that amounts are borrowed. On September 30, 2008, there were $50.0 million in outstanding borrowings under this credit facility. This facility will expire in May 2009.

In addition to the Revolving Credit Facility and the Committed Credit Facility, we had available $62.2 million of discretionary lines of credit at September 30, 2008, which expire at the bank's discretion. Except for $4.8 million, these discretionary credit lines are unsecured. 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 $7.6 million and $24.3 million in outstanding borrowings under these lines of credit at September 30, 2008 and 2007, respectively. The weighted average interest rates on short-term borrowings outstanding as of September 30, 2008 and 2007 were 5.23% and 5.40%, respectively.

The Senior Notes, Revolving Credit Facility and Committed 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 $7.6 million and $15.4 million borrowings denominated in foreign currencies at September 30, 2008 and 2007, respectively.

The fair value of financial instruments that differed from their carrying value at September 30, 2008 and 2007 was as follows (in thousands):

	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Floating rate Senior Notes due 2008	$ —	$ —	$250,000	$248,120
5.75% Senior Notes due 2011	249,825	255,225	249,760	253,900
6% Senior Notes due 2018	248,905	250,300	—	—

7. Income Taxes

The geographical sources of income before income taxes for each of the three years in the period ended September 30, 2008 were as follows (in thousands):

	2008	2007	2006
United States	$522,242	$ 831,852	$ 848,586
International	345,904	280,996	323,497
Income before income taxes	$868,146	$1,112,848	$1,172,083

The provision for income taxes for each of the three years in the period ended September 30, 2008 is summarized below (in thousands):

	2008	2007	2006
Current:			
United States—Federal	$106,467	$260,374	$267,287
United States—State	12,234	21,680	14,292
International	80,762	59,682	79,870
Total current	199,463	341,736	361,449
Deferred:			
United States—Federal	45,634	5,069	7,363
United States—State	4,872	1,258	900
International	8,812	11,145	(2,239)
Total deferred	59,318	17,472	6,024
Income tax expense	$258,781	$359,208	$367,473

The consolidated effective income tax rates (as a percent of income before income taxes) for each of the three years in the period ended September 30, 2008 varied from the U.S. statutory income tax rate for the reasons set forth below:

	2008	2007	2006
U.S. statutory rate	35.0%	35.0%	35.0%
Foreign earnings at varying rates	(4.4)	(2.9)	(2.9)
State income taxes, net of federal benefit	1.3	1.3	0.8
Other income taxes	1.8	1.0	0.7
Changes in valuation allowance	(0.5)	(0.8)	0.3
Foreign income recognized domestically	(0.1)	—	6.9
Foreign expense recognized domestically	—	—	(1.4)
Dividends received deduction	—	—	(1.7)
Domestic production activity deduction	(1.0)	(0.7)	(0.7)
Tax credits	(1.2)	(1.0)	(5.9)
Nondeductible expenses	0.5	1.0	0.8
Other, net	(1.6)	(0.6)	(0.5)
	29.8%	32.3%	31.4%

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):

	2008	2007
Assets:		
Accrued compensation expense	$ 35,769	$ 24,309
Accrued postretirement benefits	18,114	21,356
Pension liability	16,927	17,254
Deferred gain[(1)]	2,161	5,029
Accrued insurance expense	12,449	9,307
Other accrued expenses	18,009	24,651
Foreign tax credit carryforwards	—	21,375
Deferred revenue	4,151	—
Net operating and capital loss carryforwards	16,956	28,842
Valuation allowance	(8,557)	(32,012)
Total deferred tax asset	115,979	120,111
Liabilities:		
Differences in depreciable basis of property	(212,418)	(144,407)
Unrealized gain/loss	(6,332)	(10,387)
Pension asset	(2,547)	(2,639)
Earnings of foreign affiliates	—	(2,345)
Income accrued for financial reporting purposes, not yet reported for tax	—	(5,583)
Total deferred tax liability	(221,297)	(165,361)
Net deferred tax liability	$(105,318)	$ (45,250)

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

We adopted the provisions of FIN 48 on October 1, 2007. As a result of the implementation of FIN 48, we recognized a reduction of $8.1 million in the October 1, 2007 balance of retained earnings, with a corresponding increase to other long-term liabilities. As of the date of adoption we had unrecognized tax benefits of $66.6 million, all of which, if recognized, would favorably affect the effective tax rate in the period in which recognized. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows (in thousands):

	Gross Unrecognized Tax Benefits, Excluding Interest and Penalties	Interest and Penalties	Total Gross Unrecognized Tax Benefits
Balance at October 1, 2007	$ 55,295	$11,303	$ 66,598
Increases during fiscal 2008	6,241	1,305	7,546
Decreases due to resolution of uncertain tax positions	(11,153)	(3,742)	(14,895)
Balance at September 30, 2008	$ 50,383	$ 8,866	$ 59,249

We recognize potential penalties and interest related to unrecognized tax benefits as a component of income tax expense. It is reasonably possible that approximately $6 million of unrecognized tax benefits could be realized in the next twelve months, due to expiring statutes and settlements with taxing authorities.

We file tax returns in the United States and approximately fifty countries and are subject to audits periodically, none of which is expected to have a material impact on our financial statements. Due to the uncertainty and various stages of such audits, we are unable to make reasonably reliable estimates of the period of any cash settlement related to our FIN 48 liabilities or whether any material net cash settlement will be required. The United States and Canada are our major taxing jurisdictions. The earliest open tax year subject to examination is 2005 for the United States and 1999 for Canada.

At September 30, 2008, we had approximately $56.2 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: $0.3 million in 2010, $0.8 million in 2012, $2.2 million by fiscal year 2017 and the remaining $52.9 million does not expire. The state net operating losses will expire between fiscal year 2009 and fiscal year 2019.

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 will not be realized, a valuation allowance has been recorded on these amounts.

Our stock basis difference in foreign subsidiaries, for which a U.S. deferred tax liability has not been established, is approximately $624.9 million as of September 30, 2008. 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 recorded. 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 $49.9 million would be recorded as of September 30, 2008.

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, Canada Pressure Pumping, International Pressure Pumping and the Oilfield Services Group.

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

The International Pressure Pumping segment has five operating segments. Similar to U.S./Mexico and Canada Pressure Pumping, it provides 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, 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. During fiscal 2008, we revised the internal management reporting structure of our pressure pumping operations in Africa, whose results of operations were previously reported in our Europe/Africa operating segment. Our North Africa results, including Algeria and Libya, are now included in our Middle East operating segment, while our West Africa results south of Nigeria, including Angola and Gabon, are now included in our Latin America operating segment. Nigeria and coastal areas north of there remain as part of our Europe operating segment. This change does not impact our reportable segments.

The Oilfield Services segment has five operating segments. These operating segments provide other oilfield services such as casing and tubular services, process and pipeline services, chemical services, completion tools and completion fluids services in the United States 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 in the period ended September 30, 2008 is shown in the following tables (in thousands). The "Corporate" column includes corporate expenses and assets 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, 2008, 2007 and 2006, 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	Canada Pressure Pumping	International Pressure Pumping	Oilfield Services Group	Corporate	Total
2008						
Revenue	$2,777,577	$442,474	$1,252,573	$ 953,638	$ —	$5,426,262
Operating income (loss)	605,594	34,341	172,519	183,913	(89,270)	907,097
Total assets	1,749,797	515,600	1,482,655	1,055,848	518,008	5,321,908
Capital expenditures	269,294	20,163	195,854	81,133	40,422	606,866
Depreciation	117,211	34,797	68,700	34,053	10,705	265,466
2007						
Revenue	$2,562,747	$386,547	$1,074,744	$ 778,371	$ —	$4,802,409
Operating income (loss)	881,631	32,493	152,734	163,539	(79,858)	1,150,539
Total assets	1,504,397	550,449	1,339,312	980,846	340,208	4,715,212
Capital expenditures	289,278	83,643	210,684	82,796	85,712	752,113
Depreciation	89,718	29,327	55,111	27,804	7,059	209,019
2006						
Revenue	$2,353,772	$481,380	$ 884,670	$ 648,042	$ —	$4,367,864
Operating income (loss)	899,213	102,094	138,069	132,420	(100,060)	1,171,736
Total assets	1,294,946	471,362	1,022,265	707,015	366,700	3,862,288
Capital expenditures	202,423	106,352	87,822	42,499	20,878	459,974
Depreciation	65,569	24,025	49,119	22,730	5,320	166,763

Geographic Information

	Revenue	Long-Lived Assets
2008		
United States	$3,104,864	$2,220,188
Canada	522,047	331,281
Other countries	1,799,351	788,430
Total	$5,426,262	$3,339,899
2007		
United States	$2,867,442	$2,069,306
Canada	432,392	336,434
Other countries	1,502,575	575,229
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
Total	$4,367,864	$2,373,871

Revenue by Product Line

	2008	2007	2006
Cementing	$1,345,293	$1,231,643	$1,090,787
Stimulation	3,053,653	2,721,638	2,560,063
Other	1,027,316	849,128	717,014
Total revenue	$5,426,262	$4,802,409	$4,367,864

A reconciliation from the segment information to consolidated income before income taxes for each of the three years in the period ended September 30, 2008 is set forth below (in thousands):

	2008	2007	2006
Total operating income for reportable segments	$907,097	$1,150,539	$1,171,736
Interest expense	(28,112)	(32,731)	(14,558)
Interest income	1,912	1,624	14,916
Other expense, net	(12,751)	(6,584)	(11)
Income before income taxes	$868,146	$1,112,848	$1,172,083

9. Employee Benefit Plans

Defined Benefit Pension Plans

We have defined benefit pension plans covering certain employees in the United States and certain international locations, including the U.K., Canada, Norway and elsewhere. During fiscal 2004, the plans in the U.K. and Canada were frozen to new entrants. The U.S. defined benefit pension plan 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 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 early fiscal 2009, we will record a non-cash pre-tax charge of approximately $21.6 million in connection with the settlement. This consists of $5.6 million of prepaid pension cost and $16.0 million of loss currently recognized in accumulated other comprehensive income.

We also have a non-qualified supplemental executive retirement plan ("SERP"), an unfunded defined benefit pension plan that provides our executives with supplemental retirement benefits based on the highest consecutive three years compensation out of the final ten years of employment. Benefits under the SERP become vested upon the later of the executive's 55th birthday or the date the executive completes five full years of service as an officer.

Postretirement Benefit Plans

We also sponsor plans that provide certain health care and life insurance benefits for retired employees, primarily in the United States, 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. Data for the frozen U.S. defined benefit pension plan are not included in the table below, as obligations related to that plan have been effectively transferred through the insurance contract mentioned above.

Obligations and Funded Status

	U.S. SERP		Non-U.S. Pension		U.S. Postretirement	
	2008	2007	2008	2007	2008	2007
Change in benefit obligation						
Benefit obligation, beginning of year	$ 31,211	$ 21,681	$218,673	$190,113	$ 57,596	$ 55,032
Service cost	1,138	950	6,519	5,646	4,132	3,971
Interest cost	1,860	1,297	12,876	10,682	3,657	3,302
Actuarial (gain)/loss	(1,237)	4,342	(28,271)	(4,991)	(15,621)	(4,139)
Benefits paid	(816)	(128)	(6,143)	(4,986)	(444)	(570)
Contributions by plan participants	—	—	2,246	2,143	—	—
Plan amendments	38	3,069	—	—	—	—
Curtailments	—	—	—	(618)	—	—
Exchange rate adjustments	—	—	(23,761)	20,684	—	—
Benefit plan obligation, end of year	$ 32,194	$ 31,211	$182,139	$218,673	$ 49,320	$ 57,596
Change in plan assets						
Fair value of plan assets, beginning of year	$ —	$ —	$164,887	$129,127	$ —	$ —
Actual (loss)/return on plan assets	—	—	(20,333)	8,295	—	—
Contributions by employer	816	128	15,571	15,397	444	570
Contributions by plan participants	—	—	2,246	2,143	—	—
Benefits paid from plan assets	(816)	(128)	(6,143)	(4,986)	(444)	(570)
Settlements	—	—	—	(81)	—	—
Exchange rate adjustments	—	—	(17,936)	14,992	—	—
Fair value of plan assets, end of year	$ —	$ —	$138,293	$164,887	$ —	$ —
Underfunded status	$(32,194)	$(31,211)	$ (43,846)	$ (53,786)	$(49,320)	$(57,596)

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

	U.S. SERP		Non-U.S. Pension		U.S. Postretirement	
	2008	2007	2008	2007	2008	2007
Current liability	$ (2,065)	$ (408)	$ (624)	$ (639)	$ (1,086)	$ (1,510)
Non-current liability	(30,129)	(30,803)	(43,223)	(53,147)	(48,234)	(56,086)
Net amount recognized	$(32,194)	$(31,211)	$(43,846)	$(53,786)	$(49,320)	$(57,596)

The amounts recognized in accumulated other comprehensive income consist of the following as of September 30, 2008:

	U.S. SERP		Non-U.S. Pension		U.S. Postretirement	
	2008	2007	2008	2007	2008	2007
Net loss	$ 873	$2,111	$54,632	$54,056	$19,101	$3,480
Prior service cost	6,080	7,166	—	—	—	—
Net transition obligation	—	—	(84)	264	—	—
Total	$6,953	$9,277	$54,548	$54,320	$19,101	$3,480

The estimated amortization of amounts reflected in accumulated other comprehensive income into the net periodic benefit cost is expected to be $1.1 million in fiscal 2009 for the U.S. SERP, and is not expected to be material for the plans outside the United States.

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 the U.S. SERP and postretirement plan was $73.5 million and $81.9 million at September 30, 2008 and 2007, respectively. The ABO for all non-U.S. plans was $167.4 million and $202.7 million at September 30, 2008 and 2007, respectively.

The following is information for the plans with ABO's in excess of plan assets at September 30:

	U.S. SERP		Non-U.S. Pension	
	2008	2007	2008	2007
Projected benefit obligation	$32,194	$31,211	$135,885	$179,751
Accumulated benefit obligation	24,202	24,311	131,388	169,863
Plan assets at fair value	—	—	97,507	126,026

Components of Net Periodic Benefit Cost

	U.S. SERP			Non-U.S. Pension			U.S. Postretirement		
	2008	2007	2006	2008	2007	2006	2008	2007	2006
Service cost	$1,138	$ 950	$ 884	$ 6,519	$ 5,646	$ 5,212	$4,131	$3,971	$3,468
Interest cost	1,860	1,297	1,197	12,877	10,682	8,768	3,657	3,302	2,870
Expected return on plan assets	—	—	—	(11,235)	(9,696)	(8,114)	—	—	—
Recognized actuarial loss	—	—	—	2,153	3,097	2,170	—	—	—
Net amortization	1,124	996	1,115	58	(39)	18	—	—	—
Net periodic benefit cost	$4,122	$3,243	$3,196	$ 10,372	$ 9,690	$ 8,054	$7,788	$7,273	$6,338

Assumptions

The weighted average assumptions used to determine benefit obligations at September 30, were as follows:

	U.S. SERP		Non-U.S. Pension		U.S. Postretirement	
	2008	2007	2008	2007	2008	2007
Discount rate	6.5%	6.0%	6.9%	6.0%	7.6%	6.4%
Rate of increase in future compensation	5.0%	5.0%	4.6%	4.2%	n/a	n/a

The weighted average assumptions used to determine net periodic benefit costs for the years ended September 30, were as follows:

	U.S. SERP			Non-U.S. Pension			U.S. Postretirement		
	2008	2007	2006	2008	2007	2006	2008	2007	2006
Discount rate	6.0%	6.0%	7.0%	6.8%	6.0%	5.2%	6.4%	6.0%	5.8%
Expected long-term rate of return on assets	n/a	n/a	n/a	7.0%	6.8%	7.0%	n/a	n/a	n/a
Rate of increase in future compensation	5.0%	5.0%	5.0%	4.6%	4.2%	3.7%	n/a	n/a	n/a

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.

The postretirement benefit obligation at September 30, 2008 and 2007 was also determined using a health care cost inflation rate of 4%, reflecting the cap described above.

Plan Assets

Our objective is to diversify the portfolios of our pension assets 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. 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, 2008 and 2007 was:

	Non-U.S. Pension		
	Target	2008	2007
Equity securities	60-75%	61%	63%
Debt securities	25-35%	36%	35%
Other	0-5%	3%	2%

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 $16.4 million in fiscal 2008, none of which was discretionary. We infrequently make discretionary contributions. We expect to contribute $17.7 million to the defined benefit plans in fiscal 2009, which represents the legal or contractual minimum funding requirements. The postretirement plan is generally funded with the amounts necessary to meet benefit costs as they are incurred. We contributed $0.4 million in fiscal 2008 and we expect to contribute $1.6 million to the post retirement plan in fiscal 2009, which represents the anticipated claims.

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

Years ended September 30	
2009	$ 6,888
2010	10,868
2011	11,687
2012	12,813
2013	13,770
Years 2014-2018	79,350

Defined Contribution Plans

We administer defined contribution plans for employees in the United States, 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 100% up to 6% of the employee's base salary in the United States, 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 United States, the U.K. and Canada. Our matching contributions vest immediately while our base contributions become fully vested after three years of employment. Company contributions to these defined contribution plans were $30.6 million, $31.0 million, and $23.9 million, in fiscal 2008, 2007 and 2006, respectively.

Directors' Retirement Plan

We have a non-qualified directors' retirement plan. The unfunded defined benefit plan provides 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. This plan has been discontinued as of December 2007, other than for currently serving directors. The expense associated with this plan was $2.4 million, $0.2 million and $0.7 million for the years ended September 30, 2008, 2007 and 2006, respectively. Benefits paid under the plan totaled $40 thousand for each of the years ended September 30, 2008, 2007 and 2006. The related accrued benefit obligation was $5.5 million and $3.1 million as of September 30, 2008 and 2007, respectively.

10. Commitments and Contingencies

Litigation

Through performance of our service operations, we are sometimes named as a defendant in litigation, usually relating to claims for personal injury 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 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. 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. The case was settled during the third quarter of fiscal 2008. We adjusted the amount we had accrued accordingly, resulting in a $3.8 million reduction in general and administrative expense in the Corporate segment in fiscal 2008.

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 sites. 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.

Halliburton – Python Litigation

On December 21, 2007, Halliburton Energy Services, Inc. re-filed a prior suit against us and another oilfield services company for patent infringement in connection with drillable bridge plug tools. These tools are used to isolate portions of a well for stimulation work, after which the plugs are milled out using coiled tubing or a workover rig. Halliburton claims that our tools (offered under the trade name "Python") and tools offered by the other company infringe various patents for a tool constructed of composite material. The lawsuit was filed in the United States District Court for the Northern District of Texas (Dallas). This lawsuit arises from litigation filed in 2003 by Halliburton regarding the patents at issue. The earlier case was dismissed without prejudice when Halliburton sought a re-examination of the patents by the United States Patent and Trademark Office on July 6, 2004. We do not expect the outcome of this matter 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 this matter or future lawsuits, if any, that may be filed.

Investigations Regarding Misappropriation and Possible Illegal Payments

In October 2004, we received a report from a whistleblower alleging that our Asia Pacific Region Controller had misappropriated Company funds and that illegal payments had been made to government officials in that region. Management and the Audit Committee of the Board of Directors conducted investigations of these allegations, as well as questions that later arose whether illegal payments had been made elsewhere.

As a result of the theft investigation, the Region Controller admitted to multiple misappropriations and returned certain amounts to the Company. His employment was terminated in 2004.

In addition, the Audit Committee's investigation found information indicating a significant likelihood that payments, made by us to an entity in the Asia Pacific Region with which we have a contractual relationship, were then used to make payments to government officials in the region. The information also indicated that certain of our employees in the region believed that the payments by us would be used in that way. The payments, which may have been illegal, aggregated approximately $2.9 million and were made over a period of several years. The investigation also identified certain other payments as to which the legitimacy of the transactions reflected in the underlying documents could not be established or as to which questions about the adequacy of the underlying documents could not be resolved. We have voluntarily disclosed information found in the investigations to the U.S. Department of Justice ("DOJ") and U.S. Securities and Exchange Commission ("SEC") and have engaged in discussions with these authorities in connection with their review of the matter. We cannot predict whether further investigative efforts may be required or initiated by the authorities.

In May 2007, the former Region Controller pled guilty to one count of theft in Singapore. In June 2007, we filed a civil lawsuit against him seeking to recover any additional misappropriated funds and seeking an accounting of disbursements that could not be explained following the investigation. In July 2008, we reached a settlement of this litigation with the Region Controller and he made a payment to us.

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 in appropriate circumstances. Recent civil and criminal settlements with a number of public corporations and individuals have included multi-million dollar fines, disgorgement, injunctive relief, guilty pleas, deferred prosecution agreements and other sanctions, including requirements that corporations retain a monitor to oversee compliance with the FCPA. We cannot predict 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.

Environmental

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. At September 30, 2008 and 2007, we had reserved approximately $4.6 million and $3.4 million, respectively, for such environmental matters. This represents 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(R), *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 $4.2 million and $9.0 million as of September 30, 2008 and 2007, respectively. The agreement permits substitution of equipment within the partnership as long as the implied fair value of the new property transferred in at the date of substitution equals or exceeds the implied fair value, as defined, of the current property in the partnership that is being replaced. As a result of the substitutions, the deferred gain was reduced by $2.7 million in fiscal 2008 and $0.8 million in fiscal 2007. In 2010, we have the option, but not the obligation, to purchase the pumping service equipment for approximately $46 million. We currently intend 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, 2008, 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, 2009, 2010, 2011, 2012 and 2013 are $65.0 million, $43.6 million, $36.7 million, $22.1 million, and $10.5 million, respectively and $11.5 million in the aggregate thereafter.

Contractual Obligations

We routinely issue Parent Company Guarantees ("PCGs") in connection with service contracts or performance obligations 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 subsidiaries, 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 subsidiaries, 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. We have also issued standby letters of credit 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, 2008 (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	$ 33,127	$ 33,127	$ —	$ —	$ —
Guarantees	235,555	114,652	62,500	47,669	10,734
Total other commercial commitments	$268,682	$147,779	$62,500	$47,669	$10,734

11. Intangible Assets

The changes in the carrying amount of goodwill by reportable segment for each of the three years in the period ended September 30, 2008, are as follows (in thousands):

	U.S./Mexico Pressure Pumping	Canada Pressure Pumping	International Pressure Pumping	Oilfield Services Group	Total
Balance September 30, 2006	$271,781	$117,807	$255,277	$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	116,842	256,351	317,649	963,937
Impairments	—	—	(6,073)	—	(6,073)
Acquisitions	1,823	—	—	15,764	17,587
Balance September 30, 2008	$274,918	$116,842	$250,278	$333,413	$975,451

Goodwill increased $17.6 million in fiscal 2008, primarily as the result of the acquisition of Innicor Subsurface Technologies Inc. discussed in Note 3. Goodwill was reduced by $6.1 million in fiscal 2008 as the result of a $6.1 million impairment of goodwill related to our Russia operations. With the competitive pressure in the areas in which we operate in Russia, cost inflation, currency risks and concerns over future activity reductions, our analysis indicates that our goodwill associated with Russia might not be recoverable.

Technology-based intangible assets net of accumulated amortization were $31.2 million and $28.9 million at September 30, 2008 and 2007, respectively. Amortization for the three years ended September 30, 2008, 2007 and 2006 was $3.7 million, $2.2 million and $0.7 million, respectively. Estimated amortization expense for each of the subsequent five fiscal years is expected to be within the range of $4.0 million to $5.0 million.

12. Supplemental Financial Information

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

	2008	2007	2006
Consolidated statement of operations:			
Research and development expense	$ 26,302	$ 25,714	$ 24,263
Rent expense	83,756	73,051	74,222
Net operating foreign exchange gain	(21)	(417)	(1,303)
Consolidated statement of cash flows:			
Income tax paid	190,130	373,109	336,230
Interest paid	28,959	39,016	8,393
Details of acquisitions:			
Fair value of assets acquired	51,238	27,712	51,044
Liabilities assumed	11,356	5,617	31,324
Goodwill	17,292	35,825	43,085
Cash paid for acquisitions, net of cash acquired	57,174	57,920	52,172

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

	2008	2007	2006
Minority interest	$(11,903)	$(11,315)	$(3,970)
Non-operating net foreign exchange loss	(21)	(88)	(1,800)
(Loss) gain from sale of equity method investments	(2,947)	520	432
Recovery of misappropriated funds	4,000	—	2,791
Goodwill impairment	(6,073)	—	—
Other, net	4,193	4,299	2,536
Other expense, net	$(12,751)	$ (6,584)	$ (11)

Activity in the allowance for doubtful accounts for the years ended September 30 is as follows (in thousands):

	2008	2007	2006
Balance at beginning year	$20,550	$18,976	$13,938
Provision for bad debt charged to expense	9,606	6,541	5,920
Additions related to acquisitions	307	—	3,228
Write-offs of uncollectible accounts	(7,991)	(4,967)	(4,110)
Balance at end of year	$22,472	$20,550	$18,976

13. Stock-Based Compensation

We currently have two stock incentive plans and two employee stock purchase plans. Our 2000 Incentive Plan and 2003 Incentive Plan (the "Plans") provide for the granting of stock options to officers, certain eligible 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 based long term stock incentive awards, including Performance Units ("Units"), bonus stock and phantom stock, to our officers and the 2003 Plan provides for restricted stock awards to certain eligible employees and non-employee directors. An aggregate of 20.0 million shares of Common Stock has been authorized for grants under the Plans, of which 7.1 million shares were available for future grants at September 30, 2008. The 1999 Employee Stock Purchase Plan and the 2008 Employee Stock Purchase Plan (the "Purchase Plans") allow 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 22.0 million shares of Common Stock has been authorized for purchases under the Purchase Plans, of which 15.9 million shares were available for future purchases at September 30, 2008.

The following table summarizes stock-based compensation expense recognized under SFAS 123(R) for fiscal 2008, 2007 and 2006, which was allocated as follows (in thousands):

	2008	2007	2006
Cost of sales and services	$ 6,811	$ 7,168	$ 3,786
Research and engineering	1,808	1,484	1,163
Marketing	3,386	3,359	2,374
General and administrative	18,984	18,615	11,013
Stock-based compensation expense	30,989	30,626	18,336
Tax benefit	(9,053)	(7,678)	(3,631)
Stock-based compensation expense, net of tax	$21,936	$22,948	$14,705

Stock Options: The Plans provide for the granting of stock options to officers, certain eligible 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 a three-year period and are exercisable for periods ranging from seven to ten years.

Expected life was determined based on exercise history for the last ten years. Exercise history showed that officers tend to hold options for a longer period before exercising than non-officers. We segregate 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. We calculate estimated volatility using historical daily price intervals to generate expected future volatility based on the appropriate expected lives of the options. The risk-free interest rate is based on observed U.S. Treasury rates appropriate for the expected lives of the options and 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	2008	2007	2006
Expected life (years)	4.8	4.8	5.0
Interest rate	3.4%	4.6%	4.4%
Volatility	33.0%	37.0%	42.8%
Dividend yield	0.8%	0.6%	0.6%
Weighted-average fair value per share at grant date	$7.61	$12.08	$14.68
Non-officer grants			
Expected life (years)	3.6	3.7	3.0
Interest rate	3.2%	4.6%	4.4%
Volatility	33.0%	33.4%	31.9%
Dividend yield	0.8%	0.6%	0.6%
Weighted-average fair value per share at grant date	$6.51	$ 9.84	$ 9.19

A summary of stock option activity and related information is presented below (in thousands, except per share prices and years) as of September 30, 2008:

		Weighted-Average		
	Shares	Per Share Exercise Price	Remaining Contractual Term (yrs.)	Intrinsic Value
Outstanding at beginning of year	10,070	$20.46		
Granted	2,690	24.18		
Exercised	(3,131)	11.65		
Forfeited	(316)	29.88		
Outstanding at end of year	9,313	24.18	3.9	$13,100
Options exercisable at year-end	5,335	21.79	2.5	13,100

The weighted-average grant date fair value of options granted during fiscal 2008, 2007 and 2006 was $7.04, $10.69 and $11.70, respectively. The total intrinsic value of options exercised during the years ended September 30, 2008, 2007 and 2006 was $46.9 million, $7.8 million and $21.1 million, respectively.

A summary of the status of unvested shares as of September 30, 2008, and changes during fiscal 2008, is presented below (in thousands, except per share prices):

	Shares	Weighted-Average Grant-Date per Share Fair Value
Unvested at October 1, 2007	2,971	$10.40
Granted	2,690	7.04
Vested	(1,511)	9.63
Forfeited	(172)	8.42
Unvested at September 30, 2008	3,978	$ 8.47

As of September 30, 2008, there was $15.2 million of total unrecognized compensation cost related to unvested stock options. That cost is expected to be recognized over a weighted-average period of 1.5 years. The total fair value of shares vested during the years ended September 30, 2008, 2007 and 2006 was $14.5 million, $15.3 million and $9.6 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. Expense for director stock awards was $1.3 million, $1.0 million and $1.3 million in fiscal 2008, 2007 and 2006, respectively.

Stock Incentive Awards: For awards made under the 1997 Stock Incentive Plan and 2000 Stock Incentive Plan, we have reserved 345,168 shares of Common Stock for issuance for 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 market-based financial performance goals over the stipulated period. Under SFAS 123(R) compensation expense for stock-based compensation awards contingent upon a market condition is recorded for the entire grant amount regardless of achievement of the market condition. Expense for stock incentive awards was $3.1 million, $1.5 million and $3.6 million in fiscal 2008, 2007 and 2006, 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, 2008, we have accrued $1.1 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, 2004 and 2003 Unit grants, each with a three-year performance period. In accordance with SFAS 123(R), no compensation expense was reversed for the fair value of this award; however, $1.4 million, $3.2 million, and $4.2 million was reversed for the cash award component in fiscal 2008, 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, 2008 and assumptions used to determine the fair value are listed below:

Fiscal Year	Outstanding	Volatility	Discount Rate	Dividend Yield	Weighted Average Fair value per share
2008	168,144	32.34%	3.1%	0.85%	$33.90
2007	90,733	33.41%	4.7%	0.61%	$45.28
2006	151,127	45.54%	—	0.31%	$30.52

As of September 30, 2008, there was $3.4 million of total unrecognized compensation cost related to these Units. That cost is expected to be recognized over a weighted-average period of 1.6 years. We did not have any Units vest during the years ended September 30, 2008, 2007 and 2006.

In fiscal 2008 and 2007, we also granted our officers awards of bonus stock and phantom stock, 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. A portion of these awards vest quarterly over the calendar year, while the remaining vest annually. Both are contingent upon achievement of certain financial performance goals over the stipulated periods. 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 2008 and 2007 expense for the common stock award and the related cash award was $5.1 million and $4.8 million, respectively.

Purchase Plan: We issued a total of 769,428 shares for fiscal 2008 under the Purchase Plan, and have reserved 1,282,908 shares for fiscal 2009. Compensation expense determined under SFAS 123(R) for the year ended September 30, 2008 was calculated using the Black-Scholes option pricing model with the following assumptions:

	2008	2007	2006
Expected life (years)	1.0	1.0	1.0
Interest rate	4.1%	4.9%	4.1%
Volatility	31.3%	39.1%	29.6%
Dividend yield	0.8%	0.7%	0.6%
Weighted-average fair value per share at grant date	$7.08	$8.81	$9.35

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: We have authorization to issue up to 910.0 million shares of common stock.

Dividends: We paid $.05 per common share each quarter and $58.6 million in the aggregate annual amount for each of fiscal years 2008 and 2007 and $64.3 million in the aggregate annual amount for fiscal year 2006. We anticipate paying cash dividends in the amount of $.05 per common share on a quarterly basis in fiscal 2009. 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: In 1997, our Board of Directors initiated a stock repurchase program, which through a series of increases, authorizes the repurchase of up to $2.2 billion of Company stock. Repurchases are made at the discretion of management and the program will remain in effect until terminated by our Board of Directors. We purchased 84,073,882 shares at a cost of $1,730.7 million through fiscal 2006. During fiscal 2007, we purchased a total of 2,564,457 shares at a cost of $74.6 million. During fiscal 2008, we purchased a total of

101,400 shares at a cost of $2.1 million. Treasury shares have been utilized for our various stock plans as described in Note 13. A total of 3,933,259 treasury shares were used at a cost of $104.3 million in fiscal 2008, 1,110,321 treasury shares were used at a cost of $29.4 million in fiscal 2007, and 1,509,000 treasury shares were used at a cost of $21.2 million in fiscal 2006.

From October 1, 2008 through November 17, 2008, we purchased 3,466,500 shares at a cost of $44.2 million. We currently have remaining authorization to purchase up to an additional $348.4 million in stock.

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

	Pension Adjustments	Cumulative Translation Adjustment	Total
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
Changes	5,302	(16,387)	(11,085)
Balance, September 30, 2008	$(36,609)	$ 77,168	$ 40,559

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

	Before-tax Amount	Tax (Expense) Benefit	Net-of-tax Amount
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
Change in other comprehensive income	$ 45,123	$(1,300)	$ 43,823
Year Ended September 30, 2008:			
Foreign currency translation adjustment	$(16,387)	$ —	$(16,387)
Changes in defined benefit and other postretirement plans	8,547	(3,245)	5,302
Change in other comprehensive income	$ (7,840)	$(3,245)	$(11,085)

15. Quarterly Financial Data (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Fiscal Year Total
	(in thousands, except per share amounts)				
Fiscal Year 2008:					
Revenue	$1,285,065	$1,283,202	$1,328,228	$1,529,767	$5,426,262
Gross profit[1]	317,417	260,182	277,290	338,248	1,193,137
Net income	172,184	127,303	141,783	168,095	609,365
Earnings per share:					
Basic	.59	.43	.48	.57	2.08
Diluted	.58	.43	.48	.57	2.06
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

(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, 2008 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 January 29, 2009, 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 January 29, 2009, 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 January 29, 2009, 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 January 29, 2009, which section is incorporated herein by reference.

ITEM 11. Executive Compensation

Information for this item is set forth in the sections entitled "Director Compensation", "Compensation Discussion and Analysis", and "Compensation Committee Report" in the Proxy Statement of the Company for the Annual Meeting of Stockholders to be held January 29, 2009, 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" and "Equity Compensation Plan Information" in the Proxy Statement of the Company for the Annual Meeting of Stockholders to be held January 29, 2009, 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 January 29, 2009, 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 January 29, 2009, 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 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).
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).

Number	Description of Exhibit
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 6, 2007 (filed as Exhibit 3.1 to the Company's Current Report of Form 8-K dated December 12, 2007 (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	Third Supplemental Indenture, dated May 19, 2008, between BJ Services Company, as issuer, and Wells Fargo Bank, N.A., as trustee, with respect to the 6% Senior Notes due 2018 (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K filed on May 19, 2008 (file no. 1-10570) and incorporated herein by reference).
10.1	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).
10.2	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).
10.3	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).

Number	Description of Exhibit
†10.4	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).
†10.5	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).
†10.6	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).
†10.7	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).
†10.8	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).
†10.9	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).
†10.10	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).
†10.11	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).
†10.12	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).
†10.13	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).
†10.14	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).
†10.15	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).
*†10.16	Ninth Amendment effective October 13, 2008 to BJ Services Company 1997 Incentive Plan.
†10.17	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).
†10.18	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).

Number	Description of Exhibit
†10.19	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).
†10.20	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).
†10.21	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).
*†10.22	Sixth Amendment effective October 13, 2008 to BJ Services Company 2000 Incentive Plan.
†10.23	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).
†10.24	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).
*†10.25	Third Amendment effective October 13, 2008 to BJ Services Company 2003 Incentive Plan.
†10.26	2008 Employee Stock Purchase Plan (filed as Appendix A to the Company's Proxy Statement dated December 19, 2007 (file no. 1-10570) and incorporated herein by reference).
†10.27	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).
†10.28	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).
†10.29	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).
†10.30	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).
*†10.31	Amended and Restated BJ Services Company Directors' Benefit Plan, effective January 1, 2008.
†10.32	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).
†10.33	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).
†10.34	Form of 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, 2006 (file no. 1-10570) and incorporated herein by reference).

Number	Description of Exhibit
†10.35	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).
†10.36	Form of letter agreement setting forth terms and conditions of options to purchase shares of common stock awarded to non-employee directors (pre-2007 form) (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).
†10.37	Form of letter agreement setting forth terms and conditions of options to purchase shares of common stock awarded to non-employee directors (2007 form) (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed on November 21, 2006 (file no. 1-10570) and incorporated herein by reference).
*†10.38	Form of letter agreement setting forth terms and conditions of options to purchase shares of common stock awarded to non-employee directors (2008 form).
†10.39	Form of letter agreement setting forth terms and conditions of phantom stock awarded to non-employee directors (pre-2008 form) (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).
*†10.40	Form of letter agreement setting forth terms and conditions of phantom stock awarded to non-employee directors (2008 form).
†10.41	Form of letter agreement setting forth terms and conditions of options to purchase shares of common stock awarded to executive officers (pre-2007 form) (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on November 21, 2006 (file no. 1-10570) and incorporated herein by reference).
†10.42	Form of amended letter agreement setting forth terms and conditions of options to purchase shares of common stock awarded to executive officers (2007 form) (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).
*†10.43	Form of letter agreement setting forth terms and conditions options to purchase shares of common stock awarded to executive officers (2008 form).
†10.44	Form of letter agreement setting forth terms and conditions of phantom stock awarded to executive officers (pre-2008 form) (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).
*†10.45	Form of letter agreement setting forth terms and conditions of phantom stock awarded to executive officers (2008 form).
†10.46	Form of letter agreement setting forth terms and conditions of performance units awarded to executive officers (pre-2008 form) (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).
*†10.47	Form of letter agreement setting forth terms and conditions of performance units awarded to executive officers (2008 form).
†10.48	Form of letter agreement setting forth terms and conditions of bonus stock awarded to executive officers for fiscal 2008 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K/A filed on April 4, 2008 (file no. 1-10570) and incorporated herein by reference).

Number	Description of Exhibit
†10.49	Form of letter agreement setting forth terms and conditions of bonus stock awarded to executive officers for fiscal 2009 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K/A filed on November 17, 2008 (file no. 1-10570) and incorporated herein by reference).
*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 25, 2008

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 **J.W. Stewart**	Chairman of the Board, President, and Chief Executive Officer (Principal Executive Officer)	November 25, 2008
/s/ JEFFREY E. SMITH **Jeffrey E. Smith**	Senior Vice President—Finance, and Chief Financial Officer (Principal Financial Officer)	November 25, 2008
/s/ L. SCOTT BIAR **L. Scott Biar**	Vice President—Controller (Principal Accounting Officer)	November 25, 2008
/s/ L. WILLIAM HEILIGBRODT **L. William Heiligbrodt**	Director	November 25, 2008
/s/ JOHN R. HUFF **John R. Huff**	Director	November 25, 2008
Don D. Jordan	Director	November 25, 2008
/s/ WILLIAM H. WHITE **William H. White**	Director	November 25, 2008
/s/ MICHAEL E. PATRICK **Michael E. Patrick**	Director	November 25, 2008
/s/ JAMES L. PAYNE **James L. Payne**	Director	November 25, 2008

Corporate Information

Transfer Agent and Registrar:

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

American Stock Transfer & Trust Company

Domestic (800) 937-5449

Foreign (718) 921-8200

Securities transfer, change in registration, lost or stolen certificates, and address changes to:

Operations Center

6201 15th Avenue

Brooklyn, New York 11219

Answers to many of your shareholder questions and requests for forms are available by visiting American Stock Transfer & Trust Company's website at www.amstock.com

Online Submission Form:

https://secure.amstock.com/contact/nav_webrequest.asp

Account Access:

https://secure.amstock.com/shareholder/sh_login.asp

Stock Exchange Listings:

New York Stock Exchange

Chicago Board Options Exchange

Ticker Symbol "BJS" (Common Stock)

Independent Auditors:

Deloitte & Touche LLP

Houston, Texas

Form 10-K:

A copy of the Company's Annual Report to the Securities and Exchange Commission (Form 10-K) is available by writing to:

Investor Relations

BJ Services Company

P. O. Box 4442

Houston, Texas 77210-4442

Visit our website: www.bjservices.com

Annual Meeting:

The Company's Annual Meeting of Stockholders will be held at 11:00 a.m. on January 29, 2009 at the Marriott West Loop by The Galleria

1750 West Loop South, Houston Texas 77027

(713) 960-0111

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 March 10, 2008 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.

BJ Services Company
4601 Westway Park Blvd.
P.O. Box 4442
Houston, Texas 77210-4442

END