LAYNE CHRISTENSEN CO
Form 10-K
April 02, 2010

United States
Securities and Exchange Commission
Washington, D.C. 20549
Form 10-K

(Mark One)

þ **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the Fiscal Year Ended January 31, 2010

or

o **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the transition period from _________ to _________.

Commission file number: 001-34195
Layne Christensen Company
(Exact name of registrant as specified in its charter)

Delaware	48-0920712
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

1900 Shawnee Mission Parkway, Mission Woods, Kansas 66205
(Address of principal executive offices) (Zip Code)
Registrant s telephone number, including area code: (913) 362-0510
Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common stock, $.01 par value	NASDAQ Global Select Market
Preferred Share Purchase Rights	NASDAQ Global Select Market

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 o No þ

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 o No þ

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 þ No o

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o

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 definition of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o	Accelerated filer þ	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

The aggregate market value of the 18,852,593 shares of Common Stock of the registrant held by non-affiliates of the registrant on July 31, 2009, the last business day of the registrant s second fiscal quarter, computed by reference to the closing sale price of such stock on the NASDAQ Global Select Market on that date was $477,536,180.

At March 26, 2010, there were 19,502,232 shares of the Registrant s Common Stock outstanding.

Documents Incorporated by Reference

Portions of the following document are incorporated by reference into the indicated parts of this report: Definitive Proxy Statement for the 2010 Annual Meeting of Stockholders to be filed with the Commission pursuant to Regulation 14A.

PART I
Item 1. Business
General

Layne Christensen Company (we, us or the Company) provides drilling and construction services and related products in two principal markets: water infrastructure and mineral exploration, as well as operates as a producer of unconventional natural gas for the energy market. We operate throughout North America, as well as Africa, Australia, Europe and Brazil. We also operate through our affiliates in South America. Layne Christensen s customers include municipalities, investor-owned water utilities, industrial companies, global mining companies, consulting engineering firms, heavy civil construction contractors, oil and gas companies and, to a lesser extent, agribusiness.

We maintain our executive offices at 1900 Shawnee Mission Parkway, Mission Woods, Kansas, 66205. Our telephone number is (913) 362-0510 and our Web site address is www.laynechristensen.com. Our periodic and current reports are available, free of charge, on our Web site as soon as reasonably practicable after such material is filed with or furnished to the Securities and Exchange Commission.

Market Overview

The characteristics of each of the industries in which we operate are described below. See Note 17 to the Consolidated Financial Statements for certain financial information about our operating segments and foreign operations.

Water Infrastructure

Water infrastructure demand is driven by the need to provide and protect one of earth s most essential resources, water, which is drawn from the earth for drinking, irrigation and industrial use. Main drivers for water supply and treatment include shifting demographics and urban sprawl, deteriorating water quality and infrastructure that supplies our water, increasing water demand from industrial expansion, stricter regulation and new technology that allows us to achieve new standards of quality. The U.S. water well drilling industry is highly fragmented, consisting of several thousand regionally and locally based contractors. The majority of these contractors are primarily involved in drilling low-volume water wells for agricultural and residential customers, markets in which we do not generally participate.

Well and pump rehabilitation demand depends on the age and application of the equipment, the quality of material and workmanship applied in the original well construction and changes in depth and quality of the groundwater. Rehabilitation work is often required on an emergency basis or within a relatively short period of time after a performance decline is recognized. Scheduling flexibility and a broad national footprint combined with technical expertise and equipment, are critical for a repair and maintenance service provider. Like the water well drilling market, the market for rehabilitation is highly fragmented.

Demand for water and wastewater treatment services and plant construction continues to grow. Increasingly stringent water quality regulations are being adopted by a variety of governing agencies. As demographic shifts occur to more water-challenged areas and the number and allowable level of regulated contaminants and impurities becomes stricter, the demand for water recycling (re-use) and conservation services, as well as new specialized treatment media and filtration methods, is expected to remain strong.

Sewer rehabilitation demand is largely a function of deteriorating urban infrastructure and pressure from population growth. Additionally, federal and state agencies are forcing municipalities and industry to address pollution resulting from infiltration of damaged or leaking lines.

Mineral Exploration

Demand for mineral exploration drilling is driven by the need to identify, define and develop underground base and precious mineral deposits. Factors influencing the demand for mineral-related drilling services include commodity prices, growth in the economies of developing countries, international political conditions, inflation, foreign exchange levels, the economic feasibility of mineral exploration and production, the discovery rate of new mineral reserves and the ability of mining companies to access capital for their activities.

Global consumption of raw materials has been driven by the rapid industrialization and urbanization of countries such as China, India, Brazil and Russia. Development in these countries generates significant demand as their populations consume increasing amounts of base and precious metals for housing, automobiles, electronics and other durable and consumer items.

The mineral exploration market has been experiencing an unprecedented challenge in the world financial and credit markets. Many mining companies have chosen to cut their drilling programs or to cancel them in total to conserve cash. This market is dependent on financial and credit markets being readily available. In addition, low market prices for base metals have limited mining companies ability to seek cash for their operations through other avenues which traditionally have been available to them.

As mineral resources in developed countries are exhausted and new discoveries begin to slow, mining companies have focused attention on underdeveloped nations as an important source of future production. South America and Africa are key markets for our future global growth. Mining service companies with operating expertise in challenging regions should be well-positioned to capture an increasing amount of these new projects. In addition to new mine development, technological advancements in drilling and processing allow development of mineral resources previously regarded as uneconomical and should benefit the largest drilling services companies that are leading technical innovation in the mineral exploration marketplace.

Energy

The U.S. unconventional natural gas market is generally categorized as a subset of the natural gas market and includes natural gas sourced from coalbeds, shale and tight sands. With improvements in drilling and completion technologies, the supply of natural gas has increased dramatically over the last two years, particularly from unconventional shale gas reservoirs in Appalachia, the mid-continent, and east and west Texas. These shale gas reservoirs are thick and widespread, and represent a large resource base now being tapped by horizontal drilling. Large amounts of methane-rich natural gas are generated and stored in coalbeds, shales and sandstones during the coalification process, when plant material is progressively converted to coal. Production of unconventional natural gas is often accompanied by significant environmental and operational challenges, including disposal of large quantities of water, sometimes saline, that are unavoidably produced with the natural gas. Factors influencing the demand for unconventional natural gas include levels of consumption, availability of natural gas domestically and commodity prices. The exploration and production of unconventional natural gas domestically is driven by the production and use imbalance of natural gas in the U.S. and the economic feasibility from continued advances in drilling completion and production technology. Unconventional natural gas is widely accepted to be a primary future source of domestic supply. Our approximately 271,000 gross acres positions us well to provide natural gas to the domestic market.

Business Strategy

Our growth strategy

Our growth strategy is to expand our current product and service offerings and build attractive extensions of our current divisions driven by our core competencies. The key elements of this strategy include:

Selectively seek acquisition opportunities in all of our divisions

We expect to continue to evaluate acquisition opportunities to enhance our existing service offerings and to expand our geographic markets. We have available cash and credit facilities which will enable us to react to attractive opportunities. We will also pursue acquisitions we consider economic, which may expand our businesses beyond our current markets, such as international water opportunities or conventional oil and gas properties.

Expand our bundled service capabilities and geographic platform and focus on industrial end-markets for water and wastewater treatment services

We expect to expand our presence in the water well drilling and development, pump installation, well rehabilitation and specialty drilling markets by executing our proven operating strategies that we believe have made us the leader in each of these fragmented markets. We believe the growth in these market sectors will be driven by bundling products and services and marketing these offerings to a focused group of users of treatment and distribution facilities. These include municipalities, investor-owned water utilities, industrial companies and developers. By offering these services on a bundled basis, we believe we can enable our customers to expedite the typical design-build project. This will allow them to achieve economies and efficiencies over traditional unbundled services, as well as expand our market share among our existing customer base.

In addition, we are aggressively seeking to expand our water infrastructure market penetration across the U.S. by combining the service offerings provided by our recent acquisitions with our well-established relationships. Cross-selling broad service offerings into our existing base of traditional customers should enable us to expand our market share in the water infrastructure market. We intend to continue our geographic penetration primarily through organic growth, but will also seek acquisition opportunities that facilitate our access to new markets and service capabilities.

We believe our leading position as a provider of water and wastewater treatment services for the municipal end-market enhances our ability to provide complementary services to industrial end-markets. We intend to market our water infrastructure service offerings aggressively to customers in the power generation, pharmaceuticals, food and beverage and other key industrial segments. These end-markets represent large, growing and profitable opportunities that allow us to leverage our existing municipal expertise. Increased water management systems, including boiler water treatment and scrubber wastewater treatment, will be essential to support growth in generating capacity. We expect to leverage our nationwide presence and brand recognition in water infrastructure in marketing our services to these customers.

Continue to take advantage of select market conditions in mineral exploration

We believe that we are well-positioned in many of the strategic geographic locations around the world, particularly in Africa and South America, to take advantage of opportunities in these markets. Our ability to maximize these opportunities is created in part by utilizing our local market expertise and technical competence, combined with access to transferable drilling equipment and employee training and safety programs. We intend to focus on maintenance and efficiency, as well as increased scale of our operations, to improve profitability. We plan to add new rigs and replace existing rigs with more efficient equipment that will increase our capacity to grow revenue and profitability. Our improved efficiency should also help enhance margins for our services.

Develop existing unconventional natural gas opportunities and expand presence in the upstream energy market

We are selectively developing and expanding our existing unconventional natural gas properties as well as seeking opportunities in other areas, including oil and conventional natural gas. Concurrent with the development of our unconventional natural gas properties, we continue to build pipeline and natural gas gathering system infrastructure enhancing our ability to transport natural gas to market. We will continue our unconventional natural gas projects by leveraging our internal resources, drilling, engineering and geological expertise and experience in large scale developmental drilling, well completion, exploratory drilling and infrastructure engineering and operations.

Services and Products

Overview of the Company s Drilling Techniques

The types of drilling techniques employed by the Company in its drilling activities have different applications:

Conventional and reverse circulation rotary drilling is used primarily in water well applications for drilling large diameter wells and employs air or drilling fluid circulation for removal of cuttings and borehole stabilization.

Dual tube drilling, an innovation advanced by the Company primarily for mineral exploration and environmental drilling, conveys the drill cuttings to the surface inside the drill pipe. This drilling method is critical in mineral exploration drilling and environmental sampling because it provides immediate representative samples and because the drill cuttings do not contact the surrounding formation thus avoiding contamination of the borehole while providing reliable, uncontaminated samples. Because this method involves circulation of the drilling fluid inside the casing, it is highly suitable for penetration of underground voids or faults where traditional drilling methods would result in the loss of circulation of the drilling fluid, thereby preventing further penetration.

Diamond core drilling is used in mineral exploration drilling to core solid rock, thereby providing geologists and engineers with solid rock samples for evaluation.

Cable tool drilling, which requires no drilling fluid, is used primarily in water well drilling for larger diameter wells. While slower than other drilling methods, it is well suited for penetrating boulders, cobble and rock.

Auger drilling is used principally in environmental drilling applications for efficient completion of relatively small diameter, shallow borings or monitoring wells. Auger rigs are equipped with a variety of auger sizes and soil sampling equipment.

Sonic drilling provides continuous core samples of any overburden formation without the use of water or drilling additives and is able to core and drill through virtually any formation or obstruction, including bedrock. Applications include site assessments, underground storage tank investigation, delineation of contaminants, installation of monitoring wells and recovery wells, construction, geotech investigations, mineral and sand exploration, and discreet water sampling.

Water Infrastructure

We are a leading provider of water and wastewater systems and water treatment facilities. We offer, on a bundled basis, a comprehensive range of design, construction and maintenance services for municipal, industrial and agricultural water and wastewater systems. We believe our water infrastructure division is the market leader in the water well drilling industry and provides a full suite of water-related products and services.

The primary services we provide in the water infrastructure division are:

Water Systems We offer our customers every aspect of a water system, including hydrologic design and construction, source of supply exploration, well and intake construction and pipeline installation. In fiscal 2010, these services and products generated approximately 36% of revenue in the water infrastructure division. The division provides water services in most regions of the U.S. Our target groundwater drilling market consists of high-volume water wells drilled principally for municipal and industrial customers. These wells have more stringent design specifications and are typically deeper and larger in diameter than low-volume residential and agricultural wells. We have strong technical expertise, an in-depth knowledge of U.S. geology and hydrology, a well-maintained modern fleet of appropriately sized drilling equipment and a demonstrated ability to procure sizable performance bonds often required for water related projects.

Water supply development mainly requires the integration of hydrogeology and engineering with proven knowledge and application of drilling techniques. The drilling methods, size and type of equipment depend upon the depth of the wells and the geological formations encountered at the project site. We have extensive well archives in addition to technical personnel to determine geological conditions and aquifer characteristics. We provide feasibility studies using complex geophysical survey methods and have the expertise to analyze the survey results and define the source, depth and magnitude of an aquifer. We can then estimate recharge rates, recommend well design features, plan well field design and develop water management plans. To conduct these services, we maintain a staff of professional employees, including geological engineers, geologists, hydrogeologists and geophysicists. These attributes enable us to locate suitable water-bearing formations to meet a wide variety of customer requirements.

Our expertise includes all sources of water supply including groundwater as previously discussed, surface sources, and groundwater under the influence of surface waters. We design and construct bank intake structures, submerged intakes, infiltration galleries, and horizontal collector wells. We also design and construct the pipelines and pump stations necessary to convey water from its source to the users.

Well and Pump Rehabilitation We believe we are the leader in the rehabilitation of wells and well equipment. Our involvement in the initial drilling of a well positions us to win follow-up rehabilitation business, which is generally a higher margin business than well drilling. Such rehabilitation is required periodically during the life of a well. For instance, in locations where the groundwater contains bacteria, iron, or high mineral content, screen openings may become blocked, reducing the capacity and productivity of the well.

We offer complete diagnostic and rehabilitation services for existing wells, pumps and related equipment through a network of local offices throughout our geographic markets in the U.S. In addition to our well service rigs, we have equipment capable of conducting downhole closed circuit televideo inspections, one of the most effective methods for investigating water well problems, enabling us to effectively diagnose and respond quickly to well and pump performance problems. Our trained and experienced personnel can perform a variety of well rehabilitation techniques, both chemical and mechanical methods; we perform bacteriological well evaluation and water chemistry analyses to complement this effort. We also have the capability and inventory to repair, in our own machine shops, most water well pumps, regardless of manufacturer, as well as to repair well screens, casings and related equipment such as chlorinators, aerators and filtration systems.

Water and Wastewater Treatment and Plant Construction We are well-positioned to serve the needs of our municipal and industrial customers by providing the design and construction of both water and wastewater treatment plants. Continued population growth in water-challenged regions and more stringent regulatory requirements lead to increasing needs to conserve water resources and control contaminants and impurities. For the design and construction of integrated water treatment facilities and the provision of filter media and membranes, we focus on our traditional customer base served in our water well service businesses. We offer complete water treatment solutions for various groundwater contaminants and impurities, such as volatile organics, nitrates, iron, manganese, arsenic, radium, radon, uranium and perchlorate. These design and construction solutions typically involve proprietary treatment media and filtration methods, as well as treatment equipment installed at or near the wellhead, including chlorinators, aerators, filters and controls. These services are provided in connection with surface water intakes, pumping stations and groundwater pump stations. In addition to our traditional treatment equipment and filtration media, we are actively expanding our offerings and expertise in wastewater products and industrial process treatment technologies. We believe our proprietary technology, expertise and reputation in the industry will set us apart from competitors in this market.

Sewer Rehabilitation We have the capability to provide a full range of rehabilitation services through traditional pipeline replacement or trenchless, cured-in-place pipe (CIPP) technologies through our Inliner product line. CIPP is a rehabilitation method that allows existing sewer pipelines to be repaired without the need for extensive excavation and the resultant disruption of traffic flow and other services. We continually explore new rehabilitation processes and technology.

Geoconstruction We provide geoconstruction services to the heavy civil construction market that are focused primarily on soil stabilization during the construction of highways, dams, tunnels, shafts, water lines, subways and other civil construction projects. Geoconstruction services are used to modify weak and unstable soils and provide support and groundwater control for excavation. Services offered include cement and chemical grouting, jet grouting, vibratory ground improvement, drain hole drilling, installation of ground anchors, tiebacks, rock bolts and instrumentation. We have expertise in selecting the appropriate support techniques to be applied in various geological conditions in addition to extensive experience in the placement of measuring devices capable of monitoring water levels and ground movement.

Environmental Specialty Drilling Customers use our environmental drilling services to assist in assessing, investigating, monitoring and characterizing water quality and aquifer parameters. The customers are typically national and regional consulting firms engaged by federal and state agencies, as well as industrial companies that need to assess, define or clean up groundwater contamination sources. We offer a wide range of environmental drilling services including: investigative drilling, installation and testing of monitoring wells to assist the customer in determining the extent of groundwater contamination, installation of recovery wells that extract contaminated groundwater for treatment, which is known as pump and treat remediation, and specialized site safety programs associated with drilling at contaminated sites. In our environmental health sciences department, we employ a full-time staff qualified to prepare site specific health and safety plans for hazardous waste cleanup sites as required by the Occupational Safety and Health Administration (OSHA) and the Mine Safety and Health Administration (MSHA).

Mineral Exploration

Together with our Latin American affiliates, we are one of the three largest providers of drilling services for the global mineral exploration industry. Global mining companies hire us to extract samples from a site that the mining companies analyze for mineral content before investing heavily in development. Our drilling services require a high level of expertise and technical competence because the samples extracted must be free of contamination and accurately reflect the underlying mineral deposit.

Our mineral exploration division conducts aboveground and underground drilling activities, including all phases of core drilling, reverse circulation, dual tube, hammer and rotary air-blast methods. Our service offerings include both exploratory and definitional drilling. Exploratory drilling is conducted to determine if there is a minable mineral deposit, which is known as an orebody, on the site. Definitional drilling is typically conducted at a site to assess whether it would be economical to mine and to assist in mapping the mine layout. The demand for our definitional drilling services increased in recent years as new and less expensive mining techniques make it feasible to mine previously uneconomical orebodies.

Our services are used primarily by major gold and copper producers and to a lesser extent, other base metal producers. Work for gold mining customers generates approximately half of the business in our mineral exploration division. The success of our mineral exploration division is closely tied to global commodity prices and demand for our global mining customers products. Our primary markets are in the western U.S., Canada, Mexico, Australia, Brazil and Africa. We also have ownership interests in foreign affiliates operating in Latin America that form our primary presence in this market.

Energy

Our energy business operates primarily in the midwestern U.S, and includes the exploration for, and acquisition, development, and production of, unconventional natural gas.

According to the Energy Information Administration (EIA), the production rate of conventional natural gas is declining, while consumption of natural gas and other cleaner-burning fuels is increasing. Unconventional natural gas burns with essentially the same efficiency as natural gas, and we believe it is an attractive substitute fuel source in the marketplace for conventional resources.

We have developed expertise in the complex geology and engineering techniques needed to effectively develop multi-zone wells in the midwestern U.S., primarily the Cherokee Basin. As of January 31, 2010, we had approximately 271,000 gross acres under lease and 587 gross producing wells. Production from these wells increases more slowly than conventional natural gas wells and generally takes 18-24 months to reach full capacity. However, their life span is significantly longer than conventional natural gas wells. We estimate that the average life span of our current wells is approximately 10-20 years. Additionally, we continue to selectively lease acreage for purposes of expanding our development potential. We believe the increasing demand for cleaner-burning fuels and increasingly stringent regulatory limitations to ensure air quality will have a favorable impact on the price for such fuels.

When available at an economic rate, we use fixed-price physical delivery forward sales contracts to manage price fluctuation associated with our production of unconventional natural gas and achieve a more predictable cash flow. These derivative financial instruments limit our exposure to declines in prices, but also limit the benefits if prices increase. These instruments would not fully protect us from a decline in natural gas prices. As of January 31, 2010, the Company held contracts for physical delivery of 885,000 million British Thermal Units (MMBtu) of natural gas through March 31, 2010, at prices ranging from $7.68 to $10.67 per MMBtu.

Operations

We operate on a decentralized basis, with approximately 80 sales and operations offices located in most regions of the United States as well as in Australia, Africa, Mexico, Canada, Brazil and Italy. In addition, our foreign affiliates operate out of locations in South America and Mexico.

We are primarily organized around division presidents responsible for water infrastructure, mineral exploration and energy. Division vice presidents are responsible for geographic regions or product lines within each division and district managers are in charge of individual district office profit centers. The district managers report to their respective divisional vice president on a regular basis. Our primary marketing activities for our water infrastructure division are through the Company s sales engineers and project managers who cultivate and maintain contacts with existing and potential customers. We also maintain a business development effort on a national basis which seeks opportunities with industrial customers. In this way, we learn of and are in a position to compete for proposed projects. In addition, water infrastructure personnel monitor industry publications for upcoming bid opportunities.

In our foreign affiliates, where we do not have majority ownership or operating control, day-to-day operating decisions are made by local management. We manage our interests in our foreign affiliates through regular management meetings and analysis of comprehensive operating and financial information. For our significant foreign affiliates, we have entered into shareholder agreements that give us limited board representation rights and require super-majority votes in certain circumstances.

Customers and Contracts

Each of our service and product lines has major customers; however, no single customer accounted for 10% or more of the Company s revenues in any of the past three fiscal years.

Generally, we negotiate our service contracts with industrial and mining companies and other private entities, while our service contracts with municipalities are generally awarded on a bid basis. Our contracts vary in length depending upon the size and scope of the project. The majority of such contracts are awarded on a fixed price basis, subject to change of circumstance and force majeure adjustments, while a smaller portion are awarded on a cost plus basis. Substantially all of the contracts are cancelable for, among other reasons, the convenience of the customer.

In the water infrastructure division, our customers are typically municipalities and local operations of industrial businesses. Of our water infrastructure revenues in fiscal 2010, approximately 67% were derived from municipalities and approximately 16% were derived from industrial customers while the balance was derived from other customer groups. The term municipalities includes local water districts, water utilities, cities, counties and other local governmental entities and agencies that have the responsibility to provide water supplies to residential and commercial users. In the drilling of new water wells, we target customers that require compliance with detailed and demanding specifications and regulations and that often require bonding and insurance, areas in which we believe we have competitive advantages due to our drilling expertise and financial resources.

Customers for our mineral exploration services are primarily gold and copper producers. Our largest customers in our mineral exploration drilling business are multi-national corporations headquartered primarily in the United States, Brazil, Europe and Canada.

We market our unconventional gas production to large energy pipeline companies and local industrial customers.

Backlog

We track backlog only in our water infrastructure division as we do not believe it has any significance for our other businesses. Our backlog consists of the expected gross revenues associated with executed contracts, or portions thereof, not yet performed by the Company. Backlog is not necessarily a short term business indicator as there can be significant variability in the composition of the contracts and the timing of completion of the services. Our backlog for the water infrastructure division was $554.2 million at January 31, 2010, compared to $427.9 million at January 31, 2009. Our backlog as of year-end is generally completed within the following 12 to 24 months.

Seasonality

Our domestic drilling and construction activities and related revenues and earnings tend to decrease in the winter months when adverse weather conditions interfere with access to project sites. Additionally, our international mineral exploration customers tend to slow drilling activities surrounding the Christmas and New Year s holidays. As a result, our revenues and earnings in the first and fourth quarters tend to be less than revenues and earnings in the second and third quarters.

Competition

Competition for our water infrastructure division s bundled construction services are primarily local and national specialty general contractors. Our competition in the water well drilling business consists primarily of small, local water well drilling operations and some larger regional competitors. Oil and conventional natural gas well drillers generally do not compete in the water well drilling business because the typical well depths are greater for oil and conventional natural gas and, to a lesser extent, the technology and equipment utilized in these businesses are different. Only a small percentage of all companies that perform water well drilling services have the technical competence and drilling expertise to compete effectively for high-volume municipal and industrial projects, which typically are more demanding than projects in the agricultural or residential well markets. In addition, smaller companies often do not have the financial resources or bonding capacity to compete for large projects. However, there are no proprietary technologies or other significant factors which prevent other firms from entering these local or regional markets or from consolidating into larger companies more comparable in size to us. Water well drilling work is usually obtained on a competitive bid basis for municipalities, while work for industrial customers is obtained on a negotiated or informal bid basis.

As is the case in the water well drilling business, the well and pump rehabilitation business is characterized by a large number of relatively small competitors. We believe only a small percentage of the companies performing these services have the technical expertise necessary to diagnose complex problems, perform many of the sophisticated rehabilitation techniques we offer or repair a wide range of pumps in their own facilities. In addition, many of these companies have only a small number of pump service rigs. Rehabilitation projects are typically negotiated at the time of repair or contracted for in advance depending upon the lead time available for the repair work. Since well and pump rehabilitation work is typically negotiated on an emergency basis or within a relatively short period of time, those companies with available rigs and the requisite expertise have a competitive advantage by being able to respond quickly to repair requests.

Treatment plant and pipeline competitors consist mostly of a few national and many regional companies. The majority of the municipal market is contracted through a public bidding process. While the majority of the market is still price driven, a growing trend supports best value proposals.

Our mineral exploration division competes with a number of drilling companies as well as vertically integrated mining companies that conduct their own exploration drilling activities, and some of these competitors have greater capital and other resources than we have. In the mineral exploration drilling market, we compete based on price, technical expertise and reputation. We believe we have a well-recognized reputation for expertise and performance in this market. Mineral exploration drilling work is typically performed on a negotiated basis.

In the natural gas energy production market, we compete for leases, assets, services and pipeline capacity with numerous upstream oil and natural gas production companies, many of which have greater capital and other resources than we have. In our current operations, we are not constrained by the availability of a market for our production, but do compete with other exploration and production companies for mineral leases and rights-of-way in our areas of interest.

Regulation

The services we provide are subject to various licensing, permitting, approval and reporting requirements imposed by federal, state, local and foreign laws. Our operations are subject to inspection and regulation by various governmental agencies, including the Department of Transportation, OSHA and MSHA in the U.S. as well as their counterparts in foreign countries. In addition, our activities are subject to regulation under various environmental laws regarding emissions to air, discharges to water and management of wastes and hazardous substances. To the extent we fail to comply with these various regulations, we could be subject to monetary fines, suspension of operations and other penalties. In addition, these and other laws and regulations affect our mineral exploration customers and influence their determination whether to conduct mineral exploration and development. We have not and do not expect to incur significant capital expenditures to remain in compliance with these various environmental control regulations.

Many states require regulatory mandated construction permits which typically specify that wells be constructed in accordance with applicable statutes. Various state, local and foreign laws require that water wells and monitoring wells be installed by licensed well drillers. We maintain well drilling and contractor s licenses in those jurisdictions in which we operate and in which such licenses are required. In addition, we employ licensed engineers, geologists and other professionals necessary to the conduct of our business. In those circumstances in which we do not have a required professional license, we subcontract that portion of the work to a firm employing the necessary licensed professionals.

Applicable Legislation

There are a number of complex foreign, federal, state and local environmental laws which impact the demand for our environmental drilling services. For example, we currently provide a variety of services for individuals and entities that have either been ordered by the EPA or a comparable state agency to clean up certain contaminated property, or are investigating whether a particular piece of property contains any contaminants. These services include soil and groundwater testing done in connection with environmental audits, investigative drilling to determine the presence of hazardous substances, monitoring wells to detect the extent of contamination present in the groundwater and recovery wells to recover certain contaminants from the groundwater. A change in these laws, or changes in governmental policies regarding the funding, implementation or enforcement of the laws, could have a material effect on us.

Employees

At January 31, 2010, we had approximately 3,900 employees, approximately 350 of whom were members of collective bargaining units represented by locals affiliated with major labor unions in the U.S. We believe that our relationship with our employees is satisfactory. In all of our service lines, an important competitive factor is technical expertise. As a result, we emphasize the training and development of our personnel. Periodic technical training is provided for senior field employees covering such areas as pump installation, drilling technology and electrical troubleshooting. In addition, we emphasize strict adherence to all health and safety requirements and offer incentive pay based upon achievement of specified safety goals. This emphasis encompasses developing site-specific safety plans, ensuring regulatory compliance and training employees in regulatory compliance and good safety practices. Training includes an OSHA-mandated 40-hour hazardous waste and emergency response training course as well as the required annual eight-hour updates. We have a safety department staff which allows us to offer such training in-house. This staff also prepares health and safety plans for specific sites and provides input and analysis for the health and safety plans prepared by others.

On average, our field supervisors and drillers have 21 and 14 years, respectively, of experience with us. Many of our professional employees have advanced academic backgrounds in agricultural, chemical, civil, industrial, geological and mechanical engineering, geology, geophysics and metallurgy. We believe that our size and reputation allow us to compete effectively for highly qualified professionals.

Legal Proceedings

We are involved in various other matters of litigation, claims and disputes which have arisen in the ordinary course of our business. As of the date of this annual report, there are no pending material legal proceedings to which we are a party or to which our property is subject.

Item 1A. Risk Factors

Investing in our common stock involves a high degree of risk. You should carefully consider the risks described below with all of the other information contained or incorporated by reference in this annual report before deciding to invest in our common stock. If any of the following risks actually occur, they may materially harm our business and our financial condition and results of operations. In this event, the market price of our common stock could decline, and you could lose part or all of your investment.

Risks Relating To Our Business And Industry

Demand for our services is vulnerable to economic downturns and reductions in private industry and municipal spending. If general economic conditions continue or weaken and current constraints on the availability of capital continue, then our revenues, profits and our financial condition may decline.

Our customers are vulnerable to general downturns in the domestic and international economies. Consequently, our results of operations could fluctuate depending on the demand for our services.

Due to the current economic conditions and the tight credit markets, many of our customers will face considerable budget shortfalls or are delaying capital spending that will decrease the overall demand for our services. In addition, our customers may find it more difficult to raise capital in the future due to substantial limitations on the availability of credit and other uncertainties in the municipal and general credit markets.

We also expect current economic conditions to impact pricing for our services. Our customers may demand lower pricing as a condition of continuing our services. Negotiated prices for future work may also be impacted. We expect to see an increase in the number of competitors as other companies that do not normally operate in our markets enter seeking contracts to keep their resources employed.

As a result of the above conditions, our revenues, net income and overall financial condition may decline.

A decline in municipal spending on water treatment and wastewater infrastructure could reduce our revenue.

For the fiscal year ended January 31, 2010, approximately 67% of our water infrastructure division revenue was derived from contracts with governmental entities or agencies. Reduced tax revenue in certain regions, or inability to access traditional sources of credit, may limit spending and new development by local municipalities, which in turn may adversely affect the demand for our services in these regions. Reductions in spending by municipalities or local governmental agencies could reduce demand for our services and reduce our revenue.

A reduction in demand for our mineral exploration and development services could reduce our revenue.

Demand for our mineral exploration services depends in significant part upon the level of mineral exploration and development activities conducted by mining companies, particularly with respect to gold and copper. Mineral exploration is highly speculative and is influenced by a variety of factors, including the prevailing prices for various metals, which often fluctuate widely in response to global supply and demand, among other factors. In addition, the price of gold is affected by numerous factors, including international economic trends, currency exchange fluctuations, expectations for inflation, speculative activities, consumption patterns, purchases and sales of gold bullion holdings by central banks and others, world production levels and political events. In addition to prevailing prices for minerals, mineral exploration activity is influenced by the following factors:

- global and domestic economic considerations;
- the economic feasibility of mineral exploration and production;
- the discovery rate of new mineral reserves;
- national and international political conditions; and
- the ability of mining companies to access or generate sufficient funds to finance capital expenditures for their activities.

A material decrease in the rate of mineral exploration and development would reduce the revenue generated by our mineral exploration division.

Because our businesses are seasonal, our results can fluctuate significantly, which could make it difficult to evaluate our business and could cause instability in the market price of our common stock.

We periodically have experienced fluctuations in our quarterly results arising from a number of factors, including the following:

- the timing of the award and completion of contracts;
- the recording of related revenue; and
- unanticipated additional costs incurred on projects.

In addition, adverse weather conditions, natural disasters, force majeure and other similar events can curtail our operations in various regions of the world throughout the year, resulting in performance delays and increased costs. Moreover, our domestic activities and related revenue and earnings tend to decrease in the winter months when adverse weather conditions interfere with access to drilling or other construction sites. As a result, our revenue and earnings in the second and third quarters tend to be higher than revenue and earnings in the first and fourth quarters. Accordingly, as a result of the foregoing as well as other factors, our quarterly results should not be considered indicative of results to be expected for any other quarter or for any full fiscal year.

Our use of the percentage-of-completion method of accounting could result in a reduction or reversal of previously recorded results.

Our revenue on large water infrastructure contracts is recognized on a percentage-of-completion basis for individual contracts based upon the ratio of costs incurred to total estimated costs at completion. Contract price and cost estimates are reviewed periodically as work progresses and adjustments proportionate to the percentage of completion are reflected in contract revenue in the reporting period when such estimates are revised. Changes in job performance, job conditions and estimated profitability, including those arising from contract penalty provisions, and final contract settlements may result in revisions to costs and income and are recognized in the period in which the revisions are determined.

We may experience cost overruns on our fixed-price contracts, which could reduce our profitability.

A significant number of our contracts contain fixed prices and generally assign responsibility to us for cost overruns for the subject projects. Under such contracts, prices are established in part on cost and scheduling estimates, which are based on a number of assumptions, including assumptions about future economic conditions, prices and availability of materials, labor and other requirements. Inaccurate estimates, or changes in other circumstances, such as unanticipated technical problems, difficulties obtaining permits or approvals, changes in local laws or labor conditions, weather delays, cost of raw materials, or our suppliers or subcontractors inability to perform, could result in substantial losses. As a result, cost and gross margin may vary from those originally estimated and, depending upon the size of the project, variations from estimated contract performance could affect our operating results for a particular quarter. Many of our contracts also are subject to cancellation by the customer upon short notice with limited or no damages payable to us.

We have indebtedness and other contractual commitments that could limit our operating flexibility, and in turn, hinder our ability to make payments on the obligations, lessen our ability to make capital expenditures and/or increase the cost of obtaining additional financing.

As of January 31, 2010, our total indebtedness was $26.7 million, our total liabilities were $264 million and our total assets were $731 million. The current tightness in the credit markets and the terms of our credit agreements could have important consequences to stockholders, including the following:

- our ability to obtain any necessary financing in the future for working capital, capital expenditures, debt service requirements or other purposes may be limited or financing may be unavailable;
- a portion of our cash flow must be dedicated to the payment of principal and interest on our indebtedness and other obligations and will not be available for use in our business;
- our level of indebtedness could limit our flexibility in planning for, or reacting to, changes in our business and the markets in which we operate; and
- our credit agreements contain various operating and financial covenants that could restrict our ability to incur additional indebtedness and liens, make investments and acquisitions, transfer or sell assets, and transact with affiliates.

If we fail to make required debt payments, or if we fail to comply with other covenants in our credit agreements, we would be in default under the terms of these and other indebtedness agreements. This may result in the holders of the indebtedness accelerating repayment of this debt.

Our revolving credit facility will expire in November 2011 and must be extended or replaced.

Although we do not currently have any debt outstanding under our revolving credit facility, it does support approximately $20 million of letters of credit. Those letters of credit collateralize our casualty insurance programs, which would otherwise have to be cash collateralized. The facility will expire in November 2011. Should we not be able to extend or replace the revolving credit facility at economic rates and terms, we could be required to make material cash deposits to secure our insurance programs. Without access to an available credit facility, we also could be further restricted in our ability to make capital expenditures or expand the business.

There may be undisclosed liabilities associated with our acquisitions.

In connection with any acquisition made by us, there may be liabilities that we fail to discover or are unable to discover including liabilities arising from non-compliance with laws and regulations by prior owners for which we, as successor owners, may be responsible.

A significant portion of our earnings is generated from our operations, and those of our affiliates, in foreign countries, and political and economic risks in those countries could reduce or eliminate the earnings we derive from those operations.

Our earnings are significantly impacted by the results of our operations in foreign countries. Our foreign operations are subject to certain risks beyond our control, including the following:

- political, social and economic instability;
- war and civil disturbances;
- the taking of property through nationalization or expropriation without fair compensation;
- changes in government policies and regulations;
- tariffs, taxes and other trade barriers; and
- exchange controls and limitations on remittance of dividends or other payments to us by our foreign subsidiaries and affiliates.

Some of our contracts are not denominated in dollars, and, other than on a selected basis, we do not engage in foreign currency hedging transactions. An exchange rate fluctuation between the U.S. dollar and other currencies may have an adverse effect on our results of operations and financial condition.

We perform work at mining operations in countries which have experienced instability in the past, or may experience instability in the future. The mining industry is subject to regulation by governments around the world, including the regions in which we have operations, relating to matters such as environmental protection, controls and restrictions on production, and, potentially, nationalization, expropriation or cancellation of contract rights, as well as restrictions on conducting business in such countries. In addition, in our foreign operations we face operating difficulties, including political instability, workforce instability, harsh environmental conditions and remote locations. We do not maintain political risk insurance. Adverse events beyond our control in the areas of our foreign operations could reduce the revenue derived from our foreign operations to the extent that contractual provisions and bilateral agreements between countries may not be sufficient to guard our interests.

Our operations in foreign countries expose us to devaluations and fluctuations in currency exchange rates.

We operate a significant portion of our business in countries outside the U.S. The majority of our costs in those locations are transacted in local currencies. Although we generally contract with our customers in U.S. dollars, some of our contracts are not. Other than on a selected basis, we do not engage in foreign currency hedging transactions. Exchange rate fluctuations between the U.S. dollar and other currencies may have an adverse effect on our results of operations and financial condition.

Reductions in the market price of gold and base metals could significantly reduce our profit.

World gold and base metal prices historically have fluctuated widely and are affected by numerous factors beyond our control, including;

- the strength of the U.S. economy and the economies of other industrialized and developing nations;
- global or regional political or economic crises;
- the relative strength of the U.S. dollar and other currencies;
- expectations with respect to the rate of inflation;

- interest rates;
- sales of gold by central banks and other holders;
- demand for jewelry containing gold; and
- speculation.

Any material decrease in the market price of gold and base metals could reduce the demand for our mineral exploration services and reduce our profits.

Reductions in natural gas prices could further reduce our revenue and profit and curtail our future growth.

Our revenue, profitability and future growth and the carrying value of our natural gas properties depend to a large degree on prevailing natural gas prices. Prices for natural gas are subject to large fluctuations in response to relatively minor changes in the supply and demand for natural gas, uncertainties within the market and a variety of other factors beyond our control. These factors include weather conditions in the U.S., the condition of the U.S. economy, governmental regulation and the availability of alternative fuel sources.

A sharp or sustained decline in the price of natural gas would result in a commensurate reduction in our revenue, income and cash flow from the production of natural gas and could have a material adverse effect on the carrying value of our natural gas properties and the amount of our natural gas reserves. In the event prices fall substantially, we may not be able to realize a profit from our production. In recent decades, there have been periods of both worldwide overproduction and underproduction of hydrocarbons and periods of both increased and relaxed energy conservation efforts. Such conditions have resulted in periods of excess supply of, and reduced demand for natural gas. These periods have been followed by periods of short supply of, and increased demand for, natural gas.

Lower natural gas prices may not only decrease our revenue, profitability and cash flow, but also reduce the amount of natural gas that we can produce economically. This may result in our having to make additional downward adjustments to our estimated proved reserves which could be substantial. Further decreases in natural gas prices would render a significant number of our planned exploration projects uneconomical. If this occurs, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, we may be required to further write down the carrying value of our natural gas properties as a non-cash charge to earnings. We perform impairment tests on our assets periodically and whenever events or changes in circumstances warrant a review of our assets. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flow of our assets, the carrying value may not be recoverable and may, therefore, require a write-down of such carrying value. We may incur additional impairment charges in the future, which could reduce net income in the period incurred.

The current turmoil in the credit markets and poor economic conditions could negatively impact the credit worthiness of our financial counterparties.

Although we evaluate the credit capacity of our financial counterparties, current global economic conditions could negatively impact their ability to access credit. The risks of such reduction in credit capacity include:

- non-performance of institutions with whom we negotiate gas forward pricing contracts;
- viability of institutions holding our cash deposits in excess of FDIC insurance limits; and
- ability of institutions with whom we have lines of credit to allow access to those funds.

If these institutions fail to fulfill their commitments to us, our access to operating cash could be restricted.

Our forward sales contracts may not fully protect us from changes in natural gas prices.

We are exposed to fluctuations in the price of natural gas and have entered into fixed-price physical delivery forward sales contracts to manage natural gas price risk for a portion of our production. The prices at which we enter into derivative financial instruments covering our production in the future will be dependent upon commodity prices at the time we enter into these transactions, which may be substantially lower than current natural gas prices. Accordingly, our commodity price risk management strategy will not protect us from significant and sustained declines in natural gas prices received for our future production. We may not be able to obtain contracts at rates commensurate with our current contracts. Conversely, our commodity price risk management strategy may limit our ability to realize cash flow from commodity price increases. As of January 31, 2010, we had committed to deliver 885,000 million MMBtu of natural gas through March 2010 at prices ranging from $7.68 to $10.67 per MMBtu. Current market prices are such that we have not extended or replaced these contracts. If we do not do so, we will have no price protection.

The development of oil and natural gas properties is capital intensive and involves assumptions and speculation that may result in a total loss of investment.

The business of exploring for and, to a lesser extent, developing and operating oil and natural gas properties involves a high degree of business and financial risk that even a combination of experience, knowledge and careful evaluation may not be able to overcome. We intend to make selective additional investments in our energy division and intend to continue to strategically develop our existing properties and seek opportunities to lease additional acreage in the Cherokee Basin and other areas. Such expansion will require significant capital expenditure. We may drill wells that are unproductive or, although productive, do not produce oil or natural gas in economic quantities. Acquisition and well completion decisions generally are based on subjective judgments and assumptions that are speculative. It is impossible to predict with certainty the production potential of a particular property or well. Furthermore, a successful completion of a well does not ensure a profitable return on the investment. A variety of geological, operational, or market-related factors, including unusual or unexpected geological formations, pressures, equipment failures or accidents, fires, explosions, blowouts, cratering, pollution and other environmental risks, shortages or delays in the availability of drilling rigs and the delivery of equipment, inability to renew leases relating to producing properties, loss of circulation of drilling fluids or other conditions may substantially delay or prevent completion of any well, or otherwise prevent a property or well from being profitable.

If we are unable to find, develop and acquire additional oil or natural gas reserves that will be commercially viable for production, our reserves and revenue from our energy division would decline.

The rate of production from oil and natural gas properties declines as reserves are depleted. As a result, we must locate and develop or acquire new reserves to replace those being depleted by production. Without successful development or acquisition activities, our reserves and revenue from our energy division will decline. Some of our competitors in the energy business are larger, more established companies with substantially greater resources, and in many instances they have been engaged in the oil and natural gas extraction business for longer than we have. These companies may have acquisition and development strategies that are more aggressive than ours and may be able to acquire more properties or develop their existing properties much faster than we can. We endeavor to discover new economically feasible reserves at least commensurate with the depletion of our existing reserves through production. Our inability to acquire larger reserves and potential delays in the expansion of our oil or natural gas division may prevent us from gaining market share and reduce our revenue and profitability. We may not be able to find and develop or acquire additional reserves at an acceptable cost or have necessary financing for these activities in the future. In addition, drilling activity within a particular area that we lease may be unsuccessful and exploration activities may not lead to commercial discoveries of oil or natural gas. Further, we may also have to venture into more hostile environments, both politically and geographically, where exploration, development and production of oil and natural gas will be more technologically challenging and expensive.

Our estimated proved reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially reduce the quantities and present value of our reserves.

It is not possible to measure underground accumulations of oil or natural gas in an exact way. Reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future prices, production levels and operating and development costs. In estimating our level of reserves, we and our independent reserve engineers make certain assumptions that may prove to be incorrect, including assumptions relating to:

- a constant level of future prices;
- geological conditions;
- production levels;
- capital expenditures;
- operating and development costs;
- the effects of regulation; and
- availability of funds.

If these assumptions prove to be incorrect, our estimates of proved reserves, the economically recoverable quantities of oil or natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and our estimates of the future net cash flow from our reserves could change significantly.

The standardized measure of discounted cash flow is the present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC, less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue. Over time, we may make material changes to reserve estimates to take into account changes in our assumptions and the results of actual drilling and production.

The present value of future net cash flow from our estimated proved reserves is not necessarily the same as the current market value of our estimated proved reserves. We base the estimated discounted future net cash flow from our estimated proved reserves on pricing future revenues at the twelve-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the twelve-month period prior to the report period. However, actual future net cash flow from our properties also will be affected by factors such as:

- the actual prices we receive;
- our actual operating costs;
- the amount and timing of actual production;
- the amount and timing of our capital expenditures;
- the supply of and demand for oil and natural gas; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of properties will affect the timing of actual future net cash flow from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flow in compliance with guidance codified within Accounting Standards Codification (ASC) Topic 932 Extractive Activities Oil and Gas, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

If we are unable to obtain bonding at acceptable rates, our operating costs could increase.

A significant portion of our projects require us to procure a bond to secure performance. With a decreasing number of insurance providers in that market, it may be difficult to find sureties who will continue to provide contract required bonding at acceptable rates. With respect to our joint ventures, our ability to obtain a bond may also depend on the credit and performance risks of our joint venture partners, some of whom may not be as financially strong as we are. Our inability to obtain bonding on favorable terms or at all would increase our operating costs and inhibit our ability to execute projects.

Fluctuations in the prices of raw materials could increase our operating costs.

We purchase a significant amount of steel for use in connection with all of our businesses. We also purchase a significant volume of fuel to operate our trucks and equipment. The manufacture of materials used in our rehabilitation business is dependent upon the availability of resin, a petroleum-based product. At present, we do not engage in any type of hedging activities to mitigate the risks of fluctuating market prices for oil, steel or fuel and increases in the price of these materials may increase our operating costs.

The dollar amount of our backlog, as stated at any given time, is not necessarily indicative of our future earnings.

As of January 31, 2010, the backlog in our water infrastructure division was approximately $554 million. This consists of the expected gross revenue associated with executed contracts, or portions thereof, not yet performed by us. We cannot assure that the revenue projected in our backlog will be realized or, if realized, will result in profit. Further, project terminations, suspensions or adjustments in scope may occur with respect to contracts reflected in our backlog. Reductions in backlog due to cancellation by a customer or scope adjustments adversely affect, potentially to a material extent, the revenue and profit we actually receive from such backlog. We may be unable to complete some projects included in our backlog in the estimated time and, as a result, such projects could remain in the backlog for extended periods of time. Estimates are reviewed periodically and appropriate adjustments are made to the amounts included in backlog. Our backlog as of year-end is generally completed within the following 12 to 24 months. Our backlog does not include any awards for work expected to be performed more than three years after the date of our financial statements. The amount of future actual awards may be more or less than our estimates.

Our failure to meet the schedule or performance requirements of our contracts could harm our reputation, reduce our client base and curtail our future operations.

In certain circumstances, we guarantee contract completion by a scheduled acceptance date. Failure to meet any such schedule could result in additional costs, and the amount of such additional costs could exceed projected profit margins. These additional costs include liquidated damages paid under contractual penalty provisions, which can be substantial and can accrue on a daily basis. In addition, our actual costs could exceed our projections. Performance problems for existing and future contracts could increase the anticipated costs of performing those contracts and cause us to suffer damage to our reputation within our industry and our client base, which would harm our future business.

If we cannot obtain third-party subcontractors at reasonable rates, or if their performance is unsatisfactory, our profit could be reduced.

We rely on third-party subcontractors to complete some of our projects. To the extent that we cannot engage subcontractors, our ability to complete a project in a timely fashion or at a profit may be impaired. If the amount we are required to pay for subcontracted services exceeds the amount we have estimated in bidding for fixed-price work, we could experience reduced profits or losses in the performance of these contracts. In addition, if a subcontractor is unable to deliver its services according to the negotiated terms for any reason, including the deterioration of its financial condition, we may be required to purchase the services from another source at a higher price, which could reduce the profit to be realized or result in a loss on a project for which the services were needed.

Professional liability, product liability, warranty and other claims against us could reduce our revenue.

Any accidents or system failures in excess of insurance limits at locations that we engineer or construct or where our products are installed or where we perform services could result in significant professional liability, product liability, warranty and other claims against us. Further, the construction projects we perform expose us to additional risks, including cost overruns, equipment failures, personal injuries, property damage, shortages of materials and labor, work stoppages, labor disputes, weather problems and unforeseen engineering, architectural, environmental and geological problems. In addition, once our construction is complete, we may face claims with respect to the work performed.

If our joint venture partners default on their performance obligations, we could be required to complete their work under our joint venture arrangements, which could reduce our profit or result in losses.

We sometimes enter into contractual joint ventures in order to develop joint bids on contracts. The success of these joint ventures depends largely on the satisfactory performance of our joint venture partners of their obligations under the joint venture. Under these joint venture arrangements, we may be required to complete our joint venture partner s portion of the contract if the partner is unable to complete its portion and a bond is not available. In such case, the additional obligations could result in reduced profit or, in some cases, significant losses for us with respect to the joint venture.

Our business is subject to numerous operating hazards, logistical limitations and force majeure events that could significantly reduce our liquidity, suspend our operations and reduce our revenue and future business.

Our drilling and other construction activities involve operating hazards that can result in personal injury or loss of life, damage or destruction of property and equipment, damage to the surrounding areas, release of hazardous substances or wastes and other harm to the environment. To the extent that the insurance protection we maintain is insufficient or ineffective against claims resulting from the operating hazards to which our business is subject, our liquidity could be significantly reduced.

In addition, our operations are subject to delays in obtaining equipment and supplies and the availability of transportation for the purpose of mobilizing rigs and other equipment, particularly where rigs or mines are located in remote areas with limited infrastructure support. Our business operations are also subject to force majeure events such as adverse weather conditions, natural disasters and mine accidents or closings. If our drill site or construction operations are interrupted or suspended as a result of any such events, we could incur substantial losses of revenue and future business.

If we are unable to retain skilled workers, or if a work stoppage occurs as a result of disputes relating to collective bargaining agreements, our ability to operate our business could be limited and our revenue could be reduced.

Our ability to remain productive, profitable and competitive depends substantially on our ability to retain and attract skilled workers with expert geological and other engineering knowledge and capabilities. The demand for these workers is high and the supply is limited. An inability to attract and retain trained drillers and other skilled employees could limit our ability to operate our business and reduce our revenue.

As of January 31, 2010, approximately 9% of our workforce was unionized and 10 of our 29 collective bargaining agreements were scheduled to expire within the next 12 months. To the extent that disputes relating to existing or future collective bargaining agreements arise, a work stoppage could occur. If protracted, a work stoppage could substantially reduce or suspend our operations and reduce our revenue.

If we are not able to demonstrate our technical competence, competitive pricing and reliable performance to potential customers we will lose business to competitors, which would reduce our profit.

We face significant competition and a large part of our business is dependent upon obtaining work through a competitive bidding process. In our water infrastructure division, we compete with many smaller firms on a local or regional level. There are few proprietary technologies or other significant factors which prevent other firms from entering these local or regional markets or from consolidating together into larger companies more comparable in size to our company. Our competitors for our bundled construction services are primarily local and national specialty general contractors. In our mineral exploration division, we compete with a number of drilling companies, the largest being Boart Longyear Group, an Australian public company, and Major Drilling, a Canadian public company. Competition also places downward pressure on our contract prices and profit margins. Intense competition is expected to continue in these markets, and we face challenges in our ability to maintain growth rates. If we are unable to meet these competitive challenges, we could lose market share to our competitors and experience an overall reduction in our profit. Additional competition could reduce our profit.

The cost of complying with complex governmental regulations applicable to our business, sanctions resulting from non-compliance or reduced demand resulting from increased regulations could increase our operating costs and reduce our profit.

Our drilling and other construction services are subject to various licensing, permitting, approval and reporting requirements imposed by federal, state, local and foreign laws. Our operations are subject to inspection and regulation by various governmental agencies, including the Department of Transportation, OSHA and MSHA of the Department of Labor in the U.S., as well as their counterparts in foreign countries. A major risk inherent in drilling and other construction is the need to obtain permits from local authorities. Delays in obtaining permits, the failure to obtain a permit for a project or a permit with unreasonable conditions or costs could limit our ability to effectively provide our services.

In addition, these regulations also affect our mining customers and may influence their determination to conduct mineral exploration and development. Future changes in these laws and regulations, domestically or in foreign countries, could cause our customers to incur additional expenses or result in significant restrictions to their operations and possible expansion plans, which could reduce our profit.

Our water treatment business is impacted by legislation and municipal requirements that set forth discharge parameters, constrain water source availability and set quality and treatment standards. The success of our groundwater treatment services depends on our ability to comply with the stringent standards set forth by the regulations governing the industry and our ability to provide adequate design and construction solutions cost-effectively.

Presently, the exploration, development and production of oil and natural gas is subject to various types of regulation by local, state, foreign and federal agencies, including laws relating to the environment and pollution. We incur certain capital costs to comply with such regulations and expect to continue to make capital expenditures to comply with these regulatory requirements. In addition, these requirements may prevent or delay the commencement or continuance of a given operation and have a substantial impact on the growth of our energy division. Legislation affecting the oil and natural gas industry is under constant review for amendment and expansion of scope and future changes to legislation may impose significant financial and operational burdens on our business. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue and have issued rules and regulations binding on the industry and its individual members, some of which carry substantial penalties and other sanctions for failure to comply. Any increases in the regulatory burden on the industry created by new legislation would increase our cost of doing business and, consequently, lower our profitability.

Our activities are subject to environmental regulation that could increase our operating costs or suspend our ability to operate our business.

We are required to comply with foreign, federal, state and local laws and regulations regarding health and safety and the protection of the environment, including those governing the storage, use, handling, transportation, discharge and disposal of hazardous substances in the ordinary course of our operations. We are also required to obtain and comply with various permits under current environmental laws and regulations, and new laws and regulations may require us to obtain and comply with additional permits. We may be unable to obtain or comply with, and could be subject to revocation of, permits necessary to conduct our business. The costs of complying with environmental laws, regulations and permits may be substantial and any failure to comply could result in fines, penalties or other sanctions.

Various foreign, federal, state and local environmental laws and regulations may impose liability on us with respect to conditions at our current or former facilities, sites at which we conduct or have conducted operations or activities or any third- party waste disposal site to which we send hazardous wastes. The costs of investigation or remediation at these sites may be substantial. Environmental laws are complex, change frequently and have tended to become more stringent over time. Compliance with, and liability under, current and future environmental laws, as well as more vigorous enforcement policies or discovery of previously unknown conditions requiring remediation, could increase our operating costs and reduce our revenue.

If our health insurance, liability insurance or workers compensation insurance is insufficient to cover losses resulting from claims or hazards, if we are unable to cover our deductible obligations or if we are unable to obtain insurance at reasonable rates, our operating costs could increase and our profit could decline.

Although we maintain insurance protection that we consider economically prudent for major losses, we have high deductible amounts for each claim under our health insurance, workers compensation insurance and liability insurance. Our current individual claim deductible amount is $200,000 for health insurance, $1,000,000 for liability insurance and $1,000,000 for workers compensation. We cannot assure you that we will have adequate funds to cover our deductible obligations or that our insurance will be sufficient or effective under all circumstances or against all claims or hazards to which we may be subject or that we will be able to continue to obtain such insurance protection. In addition, we may not be able to maintain insurance of the types or at levels we deem necessary or adequate or at rates we consider reasonable. A successful claim or damage resulting from a hazard for which we are not fully insured could increase our operating costs and reduce our profit.

Our actual results could differ if the estimates and assumptions that we use to prepare our financial statements are inaccurate.

To prepare financial statements in conformity with generally accepted accounting principles in the U.S., we are required to make estimates and assumptions, as of the date of the financial statements that affect the reported values of assets, liabilities, revenue, expenses and disclosures of contingent assets and liabilities. Areas in which we must make significant estimates include:

- contract costs and profit and application of percentage-of-completion accounting and revenue recognition of contract claims;
- recoverability of inventory and application of lower of cost or market accounting;
- provisions for uncollectible receivables and customer claims and recoveries of costs from subcontractors, vendors and others;
- provisions for income taxes and related valuation allowances;
- recoverability of goodwill;
- recoverability of other intangibles and related estimated lives;
- valuation of assets acquired and liabilities assumed in connection with business combinations;
- accruals for estimated liabilities; including litigation and insurance reserves; and
- calculation of estimated gas reserves.

If these estimates are inaccurate, our actual results could differ.

The cost of defending litigation or successful claims against us could reduce our profit or significantly limit our liquidity and impair our operations.

We have been and from time to time may be named as a defendant in legal actions claiming damages in connection with drilling or other construction projects and other matters. These are typically actions that arise in the normal course of business, including employment-related claims and contractual disputes or claims for personal injury or property damage that occur in connection with drilling or construction site services. To the extent that the cost of defending litigation or successful claims against us are not covered by insurance, our profit could decline, our liquidity could be significantly reduced and our operations could be impaired.

If we must write off a significant amount of intangible assets or long-lived assets, our earnings will be reduced.

Because we have grown in part through acquisitions, goodwill and other acquired intangible assets represent a substantial portion of our assets. Goodwill was approximately $93 million as of January 31, 2010. If we make additional acquisitions, it is likely that we will record additional intangible assets on our books. We also have long-lived assets consisting of property and equipment and other identifiable intangible assets of $252 million as of January 31, 2010, that are reviewed for impairment annually or whenever events or circumstances indicate the carrying amount of an asset may not be recoverable. If a determination that a significant impairment in value of our unamortized intangible assets or long-lived assets occurs, such determination would require us to write off a substantial portion of our assets, which would reduce our earnings.

Difficulties integrating our acquisitions could lower our profit.

From time to time, we have made acquisitions to pursue market opportunities, increase our existing capabilities and expand into new areas of operation. We plan to pursue select acquisitions in the future. If we are unable to identify and complete such acquisitions, our growth strategy could be impaired. In addition, we may encounter difficulties integrating our acquisitions and in successfully managing the growth we expect from the acquisitions. Furthermore, expansion into new businesses may expose us to additional business risks that are different from those we have traditionally experienced. Because we may pursue acquisitions around the world and may actively pursue a number of opportunities simultaneously, we may encounter unforeseen expenses, complications and delays, including difficulties in employing sufficient staff and maintaining operational and management oversight. To the extent we encounter problems in identifying acquisition risks or integrating our acquisitions, our operations could be impaired as a result of business disruptions and lost management time, which could reduce our profit.

If we are unable to protect our intellectual property adequately, the value of our patents and trademarks and our ability to operate our business could be harmed.

We rely on a combination of patents, trademarks, trade secrets and similar intellectual property rights to protect the proprietary technology and other intellectual property that are instrumental to our water infrastructure, mineral exploration and energy operations. We may not be able to protect our intellectual property adequately, and our use of this intellectual property could result in liability for patent or trademark infringement or unfair competition. Further, through acquisitions of third parties, we may acquire intellectual property that is subject to the same risks as the intellectual property we currently own.

We may be required to institute litigation to enforce our patents, trademarks or other intellectual property rights, or to protect our trade secrets from time to time. Such litigation could result in substantial costs and diversion of resources and could reduce our profit or disrupt our business, regardless of whether we are able to successfully enforce our rights.

RISKS RELATED TO OUR COMMON STOCK

The market price of our common stock could be lowered by future sales of our common stock.

Sales by us or our stockholders of a substantial number of shares of our common stock in the public market, or the perception that these sales might occur, could cause the market price of our common stock to decline or could impair our ability to raise capital through a future sale of, or pay for acquisitions using, our equity securities.

In addition to outstanding shares eligible for future sale, as of January 31, 2010, 1,026,227 shares of our common stock were issuable under currently outstanding stock options granted to officers, directors and employees and an additional 1,537,000 shares are available to be granted under our stock option and employee incentive plans.

Future sales of these shares of our common stock could decrease our stock price.

Provisions in our organizational documents and Delaware law could prevent or frustrate attempts by stockholders to replace our current management or effect a change of control of our company.

Our certificate of incorporation, bylaws and the Delaware General Corporation Law contain provisions that could make it more difficult for a third party to acquire us without consent of our board of directors. In addition, under our certificate of incorporation, our board of directors may issue shares of preferred stock and determine the terms of those shares of stock without any further action by our stockholders. Our issuance of preferred stock could make it more difficult for a third party to acquire a majority of our outstanding voting stock and thereby effect a change in the composition of our board of directors. Our certificate of incorporation also provides that our stockholders may not take action by written consent. Our bylaws require advance notice of stockholder proposals and nominations, and permit only our board of directors, or authorized committee designated by our board of directors, to call a special stockholder meeting. These provisions may have the effect of preventing or hindering attempts by our stockholders to replace our current management. In addition, Delaware law prohibits us from engaging in a business combination with any holder of 15% or more of our capital stock until the holder has held the stock for three years unless, among other possibilities, our board of directors approves the transaction. Our board may use this provision to prevent changes in our management. Also, under applicable Delaware law, our board of directors may adopt additional anti-takeover measures in the future.

We have approved a stockholders rights agreement between us and National City Bank, as rights agent. Pursuant to this agreement, holders of our common stock are entitled to purchase one one-hundredth (1/100) of a share of Series A junior participating preferred stock at a price of $75 per one one-hundredth of a share of preferred stock upon certain events. The purchase price is subject to appropriate adjustment for stock splits and other similar events. Generally, in the event a person or entity acquires, or initiates a tender offer to acquire, at least 20% of our then outstanding common stock, the rights will become exercisable for common stock having a value equal to two times the purchase price of the right. The existence of the stockholders rights agreement may discourage, delay or prevent a third party from effecting a change of control or takeover of our company that our management and board of directors oppose.

In addition, provisions of Delaware law may also discourage, delay or prevent a third party from acquiring or merging with us or obtaining control of our company.

We are required to assess and report on our internal controls each year. Findings of inadequate internal controls could reduce investor confidence in the reliability of our financial information.

As directed by the Sarbanes-Oxley Act, the SEC adopted rules requiring public companies, including us, to include a report of management on the company s internal controls over financial reporting in their annual reports on Form 10-K that contains an assessment by management of the effectiveness of our internal controls over financial reporting. In addition, the public accounting firm auditing our financial statements must report on the effectiveness of our internal controls over financial reporting. If we are unable to conclude that we have effective internal controls over financial reporting or, if our independent registered public accounting firm is unable to provide us with an unqualified report as to the effectiveness of our internal controls over financial reporting as of each fiscal year end, investors could lose confidence in the reliability of our financial statements, which could lower our stock price.

We are restricted from paying dividends.

We have not paid any cash dividends on our common stock since our initial public offering in 1992, and we do not anticipate paying any cash dividends in the foreseeable future. In addition, our current credit arrangements restrict our ability to pay cash dividends.

Our share price could be volatile and could decline, resulting in a substantial or complete loss of your investment.

Because the trading of our common stock is characterized by low trading volume, it could be difficult for you to sell the shares of our common stock that you may hold.

The stock markets, including the NASDAQ Global Select Market, on which we list our common stock, have experienced significant price and volume fluctuations. As a result, the market price of our common stock could be similarly volatile, and you may experience a decrease in the value of the shares of our common stock that you may hold, including decreases unrelated to our operating performance or prospects. In addition, the trading of our common stock has historically been characterized by relatively low trading volume, and the volatility of our stock price could be exacerbated by such low trading volumes. The market price of our common stock could be subject to significant fluctuations in response to various factors or events, including among other things:

- our operating performance and the performance of other similar companies;
- actual or anticipated differences in our operating results;
- changes in our revenue or earnings estimates or recommendations by securities analysts;
- publication of research reports about us or our industry by securities analysts;
- additions and departures of key personnel;
- strategic decisions by us or our competitors, such as acquisitions, divestments, spin-offs, joint ventures, strategic investments or changes in business strategy;
- the passage of legislation or other regulatory developments that adversely affect us or our industry;
- speculation in the press or investment community;
- actions by institutional stockholders;
- changes in accounting principles;
- terrorist acts; and
- general market conditions, including factors unrelated to our performance.

These factors may lower the trading price of our common stock, regardless of our actual operating performance, and could prevent you from selling your common stock at or above the price that you paid for the common stock. In addition, the stock markets, from time to time, experience extreme price and volume fluctuations that may be unrelated or disproportionate to the operating performance of companies. These broad fluctuations may lower the market price of our common stock.

Item 1B. Unresolved Staff Comments

We have no unresolved comments from the Securities and Exchange Commission staff.

Item 2. Properties and Equipment

Our corporate headquarters are located in Mission Woods, Kansas (a suburb of Kansas City, Missouri), in approximately 46,000 square feet of office space leased by the Company pursuant to a written lease agreement which expires December 31, 2013.

As of January 31, 2010, we (excluding foreign affiliates) owned or leased approximately 600 drill and well service rigs throughout the world, a substantial majority of which were located in the United States. This number includes rigs used primarily in each of our service lines as well as multi-purpose rigs. In addition, as of January 31, 2010, our foreign affiliates owned or leased approximately 170 drill rigs.

Our unconventional gas projects consist of working interests in developed and undeveloped properties primarily located in the Cherokee Basin in the midwestern U.S. We also own the gas transportation facilities and equipment that transport the gas produced from our wells.

Natural Gas Reserves

The estimation of natural gas reserves is complex and requires significant judgment in the evaluation of geological, engineering and economic data. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective process and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The reserve estimates may change substantially over time as a result of additional development activities, market price, production history and the viability of production under different economic conditions. Accordingly, significant changes in estimates of existing reserves could occur, and the reserve estimates are often different from the actual quantities of natural gas that are ultimately recovered.

Our reserve and standardized measure estimates are based on independent engineering evaluations prepared by Cawley, Gillespie & Associates, Inc (CGA). A copy of the report issued by CGA is filed with this Form 10-K as exhibit 99(1). The qualifications of the person at CGA primarily responsible for overseeing his firms preparation of our reserve estimates is set forth below.

Over 20 years of experience in petroleum engineering, including reserve and economics evaluations, reservoir simulations and coalbed methane studies

Registered professional engineer in Texas

Member of the Society of Petroleum Engineers

We maintain internal controls such as the following to oversee the reserve estimation process.

No employee s compensation is based on the amount of reserves determined

Written internal policies to oversee preparation of reserves and to validate the data underlying the determinations

Compliance with our internal policies is subject to testing at least annually by personnel independent of the engineering department

Our Manager of Engineering is the technical person primarily responsible for overseeing the preparation of the reserve estimates. His qualifications include:

39 years of practical experience in petroleum engineering with 23 years of this experience being in the valuation of reserves

Licensed professional engineer in the State of Kansas

Bachelor of Science degree in engineering

Member in good standing of the Society of Petroleum Engineers

Our proved reserves and cash flow estimates as of January 31, 2010 and 2009 are presented in the following table. These estimates correspond with the methods used in developing the Supplemental Information on Oil and Gas Producing Activities accompanying the Consolidated Financial Statements in Item 8. Also presented below is the present value of estimated future net cash flows discounted at 10% on a pre-tax basis (pre-tax PV10). We believe the pre-tax PV10 is a useful measure in addition to the after-tax standardized measure. The pre-tax PV10 assists in both the determination of futures cash flows of the current reserves as well as in making relative value comparisons among peer companies.

	2010	2009
Proved developed (MMcf)	16,544	16,289
Proved undeveloped (MMcf)		274
Total proved reserves (MMcf)	16,544	16,563
Discounted future net cash flow before income taxes	$22,375	$43,431
Discounted estimated future income taxes	1,270	(3,255)
Standardized measure of discounted future net cash flow	$23,645	$40,176

The standardized measure of discounted cash flow is the present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC, less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue. Beginning at our fiscal 2010 year end, the price used in determining future net revenue was the unweighted arithmetic average of the first-day-of-the-month spot price for each month within the 12-month period to the end of the reporting period. Previously the spot price at the end of the reporting period was used. In both cases, the future net revenue also incorporates the effect of contractual arrangements such as our fixed-price physical delivery forward sales contracts. The prices used in our determinations at January 31, 2010 and 2009, were $3.24 and $3.29 per Mcf, respectively.

The standardized measure shown should not be construed as the current market value of the reserves. The 10% discount factor used to calculate present value, which is required by FASB pronouncements, is not intended to reflect current market conditions. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

During 2010, we filed estimates of our natural gas and oil reserves for the year 2009 with the Energy Information Administration of the U. S. Department of Energy on Form EIA-23L. The data on Form EIA-23L was presented on a different basis, and included 100% of the natural gas and oil volumes from our operated properties only, regardless of our net interest. The difference between the natural gas and oil reserves reported on Form EIA-23L and those reported in this report exceeds 5%.

Productive Wells and Acreage

As of January 31, 2010, we had 587 gross producing wells and 586 net producing wells. For the years ended January 31, 2010, 2009 and 2008, we produced 4,618 MMcf, 5,132 MMcf, and 4,732 MMcf of gas, respectively.

The gross and net acreage on leases expiring in each of the following five fiscal years and thereafter are as follows:

	Gross Acres	Net Acres
2011	33,056	33,056

2012	18,364	18,364
2013	74,201	74,201
2014	32,116	32,116
2015	334	334
Thereafter	3,546	3,546

Gross and net developed and undeveloped acreage as of the end of our last two fiscal years were as follows:

	Acres	
Fiscal Years Ended January 31,	2010	2009
Gross developed	111,300	102,009
Net developed	111,093	101,802
Gross undeveloped	159,740	172,509
Net undeveloped	159,740	172,509

Drilling Activity

As of January 31, 2010, we had 22 gross and net wells awaiting completion. The table below sets forth the number of wells completed at any time during the period, regardless of when drilling was initiated. Most of the wells expected to be drilled in the next year will be of the development category and in the vicinity of our existing or planned construction pipeline network. Our drilling, abandonment, and acquisition activities for the periods indicated are shown below:

Fiscal Years Ended January 31,	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Capable of production						
Dry						
Development wells:						
Capable of production	5	5	116	116	92	104
Dry						
Wells abandoned						
Acquired wells						
Net increase in capable wells	5	5	116	116	92	104

The amounts shown as gross and net development wells in 2008 are net of 18 gross and six net wells which were disposed of during the year in exchange for an overriding royalty interest.

Delivery Commitments

The Company, through its gas pipeline operations, sells its gas production primarily to gas marketing firms at the spot market and under fixed-price physical delivery forward sales contracts. The Company expects current production will be sufficient to meet the requirements under the contracts. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for further discussion of the contracts.

Item 3. Legal Proceedings

We are involved in various matters of litigation, claims and disputes which have arisen in the ordinary course of our business. As of the date of this annual report, there are no pending material legal proceedings to which we are a party or to which our property is subject. We believe that the ultimate disposition of these matters will not, individually and in the aggregate, have a material adverse effect upon our business or consolidated financial position, results of operations or cash flows.

Item 4. Reserved

Item 4A. Executive Officers of the Registrant

Executive officers of the Company are appointed by the Board of Directors or the President for such terms as shall be determined from time to time by the Board or the President, and serve until their respective successors are selected and qualified or until their respective earlier death, retirement, resignation or removal.

Set forth below are the name, age and position of each executive officer of the Company.

Name	Age	Position
Andrew B. Schmitt	61	President, Chief Executive Officer and Director
Jeffrey J. Reynolds	43	Executive Vice President of Operations and Director
Gregory F. Aluce	54	Senior Vice President and Division President Water Resources
Eric R. Despain	61	Senior Vice President and Division President Mineral Exploration
Steven F. Crooke	53	Senior Vice President, Secretary and General Counsel
Jerry W. Fanska	61	Senior Vice President-Finance and Treasurer

The business experience of each of the executive officers of the Company is as follows:

Andrew B. Schmitt has served as President and Chief Executive Officer since October 1993. For approximately two years prior to joining the Company, Mr. Schmitt managed two privately-owned hydrostatic pump and motor manufacturing companies and an oil and gas service company. He served as President of the Tri-State Oil Tools Division of Baker Hughes Incorporated from February 1988 to October 1991.

Jeffrey J. Reynolds became a director and Senior Vice President of the Company on September 28, 2005, in connection with the acquisition of Reynolds, Inc. by Layne Christensen Company. Mr. Reynolds served as the President of Reynolds, Inc., a company which provides products and services to the water and wastewater industries, from 2001 until February of 2010. On March 30, 2006, Mr. Reynolds was promoted to Executive Vice President of the Company overseeing the Water Infrastructure Division and on February 1, 2010, Mr. Reynolds was promoted to Executive Vice President of Operations for the Company overseeing all of the Company s operating divisions.

Gregory F. Aluce has served as Senior Vice President since April 14, 1998. Since September 1, 2001, Mr. Aluce has also served as President of the Company s water resource division, a component of the water infrastructure division, and is responsible for the Company s groundwater supply, well and pump rehabilitation and potable water treatment services. Mr. Aluce has over 25 years experience in various areas of the Company s operations.

Eric R. Despain has served as Senior Vice President since February 1996. Since September 1, 2001, Mr. Despain has also served as President of the Company s mineral exploration division and is responsible for the Company s mineral exploration operations. Prior to joining the Company in December 1995, Mr. Despain was President, Chief Executive Officer and a member of the Board of Directors of Christensen Boyles Corporation since 1986.

Steven F. Crooke has served as Vice President, Secretary and General Counsel since May 2001. For the period of June 2000 through April 2001, Mr. Crooke served as Corporate Legal Affairs Manager of Huhtamaki Van Leer. Prior to that, he served as Assistant General Counsel of the Company from 1995 to May 2000. On February 1, 2006, Mr. Crooke was promoted to Senior Vice President, Secretary and General Counsel.

Jerry W. Fanska has served as Vice President Finance and Treasurer since April 1994. Prior to joining Layne Christensen, Mr. Fanska served as corporate controller of The Marley Company since October 1992 and as its Internal Audit Manager since April 1984. On February 1, 2006, Mr. Fanska was promoted to Senior Vice President Finance and Treasurer.

PART II

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

The Company s common stock is traded on the NASDAQ Global Select Market under the symbol LAYN. In the year ended January 31, 2010, the Company purchased and subsequently cancelled 5,374 shares of stock related to settlement of withholding obligations. The following table sets forth the range of high and low sales prices of the Company s stock by quarter for fiscal 2010 and 2009, as reported by the NASDAQ Global Select Market.

Fiscal Year 2010	High	Low
First Quarter	$23.43	$14.13
Second Quarter	24.14	17.53
Third Quarter	35.14	21.69
Fourth Quarter	29.99	24.72

Fiscal Year 2009	High	Low
First Quarter	$45.83	$32.08
Second Quarter	53.37	38.79
Third Quarter	58.26	16.54
Fourth Quarter	27.80	10.36

At March 26, 2010, there were 99 owners of record of the Company s common stock.

The Company has not paid any cash dividends on its common stock. Moreover, the Board of Directors of the Company does not anticipate paying any cash dividends in the foreseeable future. The Company s future dividend policy will depend on a number of factors including future earnings, capital requirements, financial condition and prospects of the Company and such other factors as the Board of Directors may deem relevant, as well as restrictions under the Credit Agreement between the Company and Bank of America, as administrative agent for a group of banks, the Master Shelf Agreement between the Company and Prudential Investment Management, Inc., The Prudential Insurance Company of America, Pruco Life Insurance Company and Security Life of Denver Insurance Company, and other restrictions which may exist under other credit arrangements existing from time to time. The Credit Agreement and the Master Shelf Agreement limit the cash dividends payable by the Company.

See Note 2 of the Notes to Consolidated Financial Statements for discussion of common stock issued by the Company during the last three years in connection with acquisitions. All such stock was unregistered.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of January 31, 2010, with respect to shares of the Company s common stock that have been authorized for issuance under the existing equity compensation plans, including the Company s 2006 Equity Plan and 2002 Option Plan.

The table does not include information with respect to shares subject to outstanding options granted under equity compensation plans that are no longer in effect. Footnote 3 to the table sets forth the total number of shares of the Company s common stock issuable upon the exercise of options under expired plans as of January 31, 2010, and the weighted average exercise price of those options. No additional options may be granted under such plans.

	Number of securities remaining available for future issuance under equity

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	910,926(1)	$ 25.29	1,287,063(2)
Equity compensation plans not approved by security holders		N/A	
Total	910,926(3)		1,287,063

(1) Shares issuable pursuant to outstanding options under the 2006 Equity Plan and the 2002 Option Plan.

(2) All shares listed are issuable pursuant to future awards under the 2006 Equity Plan.

(3) The table does not include information for equity compensation plans that have expired. The Company s 1992 Option Plan expired in May 2002. As of January 31, 2010, no shares of Company common stock

were issuable upon the exercise of outstanding options under the expired 1992 Option Plan. No additional options may be granted under the 1992 Option Plan. The Company s 1996 Option Plan expired in May 2006. As of January 31, 2010, a total of 115,301 shares of Company common stock were issuable upon the exercise of outstanding options under the expired 1996 Option Plan. The weighted average exercise price of those options is $21.40 per share. No additional options may be granted under the 1996 Option Plan.

Item 6. Selected Financial Data

The following selected historical financial information as of and for each of the five fiscal years ended January 31, 2010, has been derived from the Company s audited Consolidated Financial Statements. The Company completed various acquisitions in each of the fiscal years, which are more fully described in Note 2 of the Notes to Consolidated Financial Statements or in previously filed Forms 10-K. The acquisitions have been accounted for under the purchase method of accounting and, accordingly, the Company s consolidated results include the effects of the acquisitions from the date of each acquisition.

The Company sold various operating companies during 2004 and classified their results as discontinued operations for all years presented. The information below should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations under Item 7 and the Consolidated Financial Statements and Notes thereto included elsewhere in this Form 10-K.

Fiscal Years Ended January 31,	2010	2009	2008	2007	2006
Income Statement Data (in thousands, except per share data):					
Revenues	$ 866,417	$ 1,008,063	$ 868,274	$ 722,768	$ 463,015
Cost of revenues (exclusive of depreciation, depletion, amortization and impairment shown below)	(661,552)	(756,083)	(638,003)	(536,373)	(344,628)
Selling, general and administrative expense	(128,244)	(136,687)	(119,937)	(102,603)	(69,979)
Depreciation, depletion and amortization	(57,679)	(52,840)	(43,620)	(32,853)	(20,024)
Impairment of oil and gas properties	(21,642)	(28,704)			
Litigation settlement gains	3,495	2,173			
Equity in earnings of affiliates	8,198	14,089	8,076	4,452	4,345
Interest expense	(2,734)	(3,614)	(8,730)	(9,781)	(5,773)
Other income, net	199	1,041	1,229	2,557	900
Income from continuing operations before income taxes	6,458	47,438	67,289	48,167	27,856
Income tax expense	(5,093)	(21,266)	(30,178)	(21,915)	(13,121)
Net income from continuing operations before discontinued operations	1,365	26,172	37,111	26,252	14,735
Net loss (income) attributable to noncontrolling interest		362	145		(50)
Net income attributable to Layne Christensen Company from continuing operations before discontinued operations	1,365	26,534	37,256	26,252	14,685
Gain (loss) from discontinued operations, net of income taxes					(4)
Net income attributable to Layne Christensen Company	$ 1,365	$ 26,534	$ 37,256	$ 26,252	$ 14,681

Basic income per share:					
Net income from continuing operations	$ 0.07	$ 1.38	$ 2.23	$ 1.71	$ 1.08
Income (loss) from discontinued operations, net of income taxes					
Net income per share	$ 0.07	$ 1.38	$ 2.23	$ 1.71	$ 1.08
Diluted income per share:					
Net income from continuing operations	$ 0.07	$ 1.37	$ 2.20	$ 1.68	$ 1.05
Income (loss) from discontinued operations, net of income taxes					
Net income per share	$ 0.07	$ 1.37	$ 2.20	$ 1.68	$ 1.05
Balance Sheet Data (in thousands):					
Working capital, including current maturities of debt	$ 119,649	$ 128,610	$ 127,696	$ 66,989	$ 69,996
Total assets	730,955	719,357	696,955	547,164	449,335
Total long term debt, excluding current maturities	6,667	26,667	46,667	151,600	128,900
Total Layne Christensen Company stockholders equity	466,798	456,022	423,372	205,034	171,626

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

The following discussion and analysis of financial condition and results of operations should be read in conjunction with the Company s Consolidated Financial Statements and Notes thereto under Item 8.

Cautionary Language Regarding Forward-Looking Statements

This Form 10-K may contain forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Exchange Act of 1934. Such statements may include, but are not limited to, statements of plans and objectives, statements of future economic performance and statements of assumptions underlying such statements, and statements of management s intentions, hopes, beliefs, expectations or predictions of the future. Forward-looking statements can often be identified by the use of forward-looking terminology, such as should, intended, continue, believe, may, hope, anticipate, goal, forecast, plan, estimate and similar word statements are based on current expectations and are subject to certain risks, uncertainties and assumptions, including but not limited to prevailing prices for various commodities, unanticipated slowdowns in the Company s major markets, the risks and uncertainties normally incident to the exploration for and development and production of oil and gas, the impact of competition, the effectiveness of operational changes expected to increase efficiency and productivity, worldwide economic and political conditions and foreign currency fluctuations that may affect worldwide results of operations. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary materially and adversely from those anticipated, estimated or projected. These forward-looking statements are made as of the date of this filing, and the Company assumes no obligation to update such forward-looking statements or to update the reasons why actual results could differ materially from those anticipated in such forward-looking statements.

Management Overview of Reportable Operating Segments

The Company is a multinational company that provides sophisticated drilling and construction services and related products to a variety of markets, as well as operates as a producer of unconventional natural gas for the energy market. Management defines the Company s operational organizational structure into discrete divisions based on its primary product lines. Each division comprises a combination of individual district offices, which primarily offer similar types of services and serve similar types of markets. Although individual offices within a division may periodically perform services normally provided by another division, the results of those services are recorded in the office s own division. For example, if a mineral exploration division office performed water well drilling services, the revenues would be recorded in the mineral exploration division rather than the water infrastructure division. The Company s reportable segments are defined as follows:

Water Infrastructure Division

This division provides a full line of water and wastewater related services and products including soil stabilization, hydrological studies, site selection, well design, drilling and well development, pump installation and well rehabilitation. The division s offerings include the design and construction of treatment facilities and the provision of filter media and membranes to treat volatile organics and other contaminants such as nitrates, iron, manganese, arsenic, radium and radon in groundwater. The division also offers environmental drilling services to assess and monitor groundwater contaminants.

Through internal growth and acquisitions, the division has continued to expand its capabilities in the areas of the design and build of water and wastewater treatment plants, Ranney collector wells, water treatment product research and development, sewer rehabilitation and water and wastewater transmission lines.

The division s operations rely heavily on the municipal sector as approximately 67% of the division s fiscal 2010 revenues were derived from the municipal market. The municipal sector can be adversely impacted by economic slowdowns. Reduced tax revenues can limit spending and new development by local municipalities. Generally, spending levels in the municipal sector lag an economic recession or recovery.

Mineral Exploration Division

This division provides a complete range of drilling services for the mineral exploration industry. Its aboveground and underground drilling activities include all phases of core drilling, diamond, reverse circulation, dual tube, hammer and rotary air-blast methods.

Demand for the Company s mineral exploration drilling services depends upon the level of mineral exploration and development activities conducted by mining companies, particularly with respect to gold and copper. Mineral exploration is highly speculative and is influenced by a variety of factors, including the prevailing prices for various metals that often fluctuate widely and the availability of credit for mining companies. In this connection, the recent decline in the level of mineral exploration and development activities conducted by mining companies is expected to have a material adverse effect on the Company. It is expected that activity by mining companies will not improve until financial and credit markets become more readily available. The current market prices for base metals have also limited mining companies ability to seek cash for their operations through other avenues which have traditionally been available to them.

The division relies heavily on mining activity in Africa where 29% of total division revenues were generated for fiscal 2010. The Company believes this concentration of risk is mitigated by working for larger international mining companies and the establishment of permanent operating facilities in Africa. Operating difficulties, including but not limited to, political instability, workforce instability, harsh environment, disease and remote locations, all create natural barriers to entry in this market by competitors. The Company believes it has positioned itself as the market leader in Africa and has established the infrastructure to operate effectively.

Energy Division

This division focuses on the exploration and production of unconventional gas properties. This division has primarily been concentrated on projects in the mid-continent region of the United States.

The expansion of the Company s energy segment is contingent upon significant cash investments to develop the Company s unproved acreage. As of January 31, 2010, the Company has invested $157,940,000 in oil and gas related assets and expects to spend approximately $5,000,000 in development activities in fiscal 2011.

The production curve for a typical unconventional gas well in the Company s operating market is generally 15-20 years. Accordingly, the Company expects to earn a return on its investment through proceeds from gas production over an extended period.

However, future revenues and profits will be dependent upon a number of factors including consumption levels for natural gas, commodity prices, the economic feasibility of gas exploration and production and the discovery rate of new gas reserves. The Company has 586 net producing wells on-line as of January 31, 2010.

Other

Other includes two small specialty energy service companies and any other specialty operations not included in one of the other divisions.

The following table, which is derived from the Company s Consolidated Financial Statements as discussed in Item 6, presents, for the periods indicated, the percentage relationship which certain items reflected in the Company s Statements of Income bear to revenues and the percentage increase or decrease in the dollar amount of such items period-to-period.

	Fiscal Years Ended January 31,			Period-to-Period Change	
	2010	2009	2008	2010 vs. 2009	2009 vs. 2008
Revenues:					
Water infrastructure	80.6%	76.1%	73.7%	(8.9)%	19.9%
Mineral exploration	13.7	18.7	20.5	(37.4)	5.8
Energy	5.3	4.6	4.6	(0.9)	16.6
Other	0.4	0.6	1.2	(35.2)	(44.2)
Total revenues	100.0	100.0	100.0	(14.1)	16.1
Cost of revenues (exclusive of depreciation, depletion, amortization and impairment shown below)	(76.3)	(75.0)	(73.5)	(12.5)	18.5
Selling, general and administrative expense	(14.8)	(13.6)	(13.8)	(6.2)	14.0
Depreciation, depletion and amortization	(6.7)	(5.2)	(5.0)	9.2	21.1
Impairment of oil and gas properties	(2.5)	(2.8)		(24.6)	*
Litigation settlement gains	0.4	0.2		60.8	*
Equity in earnings of affiliates	0.9	1.4	0.9	(41.8)	74.5
Interest expense	(0.3)	(0.4)	(1.0)	(24.3)	(58.6)
Other, net		0.1	0.2	*	*
Income before income taxes	0.7	4.7	7.8	(86.4)	(29.5)
Income tax expense	(0.5)	(2.1)	(3.5)	(76.1)	(29.5)

Net income	0.2	2.6	4.3	(94.8)	(29.5)
Net loss attributable to noncontrolling interest				*	*
Net income attributable to Layne Christensen Company	0.2%	2.6%	4.3%	(94.9)%	(28.8)%

* not meaningful

Revenues, equity in earnings of affiliates and income before income taxes pertaining to the Company s operating segments are presented on the next page. Unallocated corporate expenses primarily consist of general and administrative functions performed on a company-wide basis and benefiting all operating segments.

These costs include accounting, financial reporting, internal audit, safety, treasury, corporate and securities law, tax compliance, certain executive management (chief executive officer, chief financial officer and general counsel) and board of directors. Operating segment revenues and income before income taxes are summarized as follows:

(in thousands) Fiscal Years Ended January 31,	2010	2009	2008
Revenues			
Water infrastructure	$698,506	$ 766,957	$639,584
Mineral exploration	118,188	188,918	178,482
Energy	45,940	46,352	39,749
Other	3,783	5,836	10,459
Total revenues	$866,417	$1,008,063	$868,274
Equity in earnings of affiliates			
Mineral exploration	$ 8,198	$ 14,089	$ 8,076
Income (loss) before income taxes			
Water infrastructure	$ 33,017	$ 48,399	$ 42,995
Mineral exploration	11,149	39,260	37,452
Energy	(6,393)	(12,401)	13,075
Other	308	1,280	3,696
Unallocated corporate expenses	(28,889)	(25,486)	(21,199)
Interest expense	(2,734)	(3,614)	(8,730)
Total income before income taxes	$ 6,458	$ 47,438	$ 67,289

Comparison of Fiscal 2010 to Fiscal 2009

Revenues for fiscal 2010 decreased $141,646,000, or 14.1%, to $866,417,000 compared to $1,008,063,000 for fiscal 2009. A further discussion of results of operations by division is presented below.

Selling, general and administrative expenses decreased to $128,244,000 for fiscal 2010 compared to $136,687,000 for fiscal 2009 (14.8% and 13.6% of revenues, respectively). The decrease was primarily the result of decreased compensation related expenses, lower legal, professional and consulting fees and reduced travel. These reductions were partially offset by $4,980,000 in settlement charges recorded for the elimination of our hourly pension plan liabilities and increased non-income tax expenses of $2,577,000. Compensation expenses declined based on lower incentive compensation given the Company s reduced earnings, as well as headcount reductions. Other expense reductions were primarily due to lower activity levels and cost control measures. The increased non-income tax expenses were primarily due to a reassessment in the first quarter of the recoverability of value added tax balances in certain foreign jurisdictions given declines in those economies and higher business tax expenses in those jurisdictions.

Depreciation, depletion and amortization increased to $57,679,000 for fiscal 2010 compared to $52,840,000 for fiscal 2009. The increase was primarily due to higher depletion in the energy division and depreciation on recent capital expenditures in the water infrastructure division. The higher depletion is a result of reduced estimated proved oil and gas reserves due to lower spot gas prices, which are used in estimating future economic production.

The Company recorded non-cash impairments to oil and gas properties of $21,642,000 in fiscal 2010 compared to $28,704,000 in fiscal 2009, with 2009 including $2,014,000 related to an exploration project in Chile. The impairments are primarily a result of low gas prices in the Company s markets, as noted above, and the expiration of higher priced forward sales contracts. On an after tax basis, the impairments were $13,039,000 and $17,251,000 for 2010 and 2009, respectively.

The Company recorded litigation settlement gains of $3,495,000 and $2,173,000 for the years ended January 31, 2010 and 2009. The settlements in 2010 included receipt of land and buildings valued at $2,828,000, and cash receipts of $667,000, net of contingent attorney fees. Cash receipts, net of contingent attorney fees, of $2,173,000 were received for the year ended January 31, 2009.

Equity in earnings of affiliates decreased to $8,198,000 for fiscal 2010 compared to $14,089,000 for fiscal 2009. The decrease reflects the impact of a soft minerals exploration market in Latin America, primarily for gold and copper.

Interest expense decreased to $2,734,000 for fiscal 2010 compared to $3,614,000 for fiscal 2009. The decrease was primarily a result of scheduled debt reductions.

The Company recorded income tax expenses of $5,093,000 (an effective rate of 78.9%) and $21,266,000 (an effective rate of 44.8%) for fiscal 2010 and 2009, respectively. The effective rates exceeded statutory rates due to the impact of nondeductible expenses and the taxation of foreign income. The Company s effective rate in both years was further impacted by lower pretax income as a result of the non-cash impairment charges in the Energy division. Excluding the impairments and related tax benefits, the Company would have recorded income tax expenses of $13,696,000 (an adjusted effective rate of 48.7%) and $32,719,000 (an adjusted effective rate of 43.0%) for each year. The higher adjusted effective rate in 2010 over 2009 resulted primarily from the impact of nondeductible expenses as adjusted pretax income declined.

Water Infrastructure Division

(in thousands) Fiscal Years Ended January 31,	2010	2009
Revenues	$698,506	$766,957
Income before income taxes	33,017	48,399

Water infrastructure revenues decreased 8.9% to $698,506,000 for fiscal 2010, from $766,957,000 for fiscal 2009. The decrease occurred across all major product lines, except Ranney collector wells and our specialty geoconstruction services. The decreases were partially offset by revenues from recently acquired businesses of $30,101,000. Although revenues were down across the country, the most affected locations were in the western U.S., where weakness in housing construction and lower municipal government spending has significantly impacted our markets. Revenues for our specialty geoconstruction services were strong in the second half of the year due to a contract to assist in flood control in New Orleans. The contract is expected to last into the first quarter of fiscal 2011.

Income before income taxes for the water infrastructure division decreased 31.8% to $33,017,000 for fiscal 2010, compared to $48,399,000 for fiscal 2009. Reduced revenue levels and margin pressures from increased competition, as well as difficulties on several projects, contributed to the decline. Profits on the New Orleans project partially offset declines in the last six months. Cost control measures, including headcount reductions, continue as we seek to match expenses to lower activity levels in most of our product lines.

The backlog in the water infrastructure division was $554,211,000 as of January 31, 2010, compared to $427,863,000 as of January 31, 2009.

Mineral Exploration Division

(in thousands) Fiscal Years Ended January 31,	2010	2009
Revenues	$118,188	$188,918
Income before income taxes	11,149	39,260

Mineral exploration revenues decreased 37.4% to $118,188,000 for fiscal 2010, compared to revenues of $188,918,000 for fiscal 2009. The decreased activity levels which began in the fourth quarter of last year continued for much of the year, with revenue declines in virtually all of the division s markets driven by economic uncertainty. Revenue did improve somewhat in the fourth quarter, with revenue $7,329,000 higher than the fourth quarter last year. The increase was primarily in Mexico and West Africa.

Income before income taxes for the mineral exploration division decreased 71.6% to $11,149,000 for fiscal 2010, compared to $39,260,000 for fiscal 2009. During the current year, we had two unusual items, receipt of a litigation settlement in Australia of $2,828,000 and increased non-income tax expense of $2,577,000 due to a reassessment of the recoverability of value added taxes and accruals for certain other business tax expenses in foreign jurisdictions. Operations in North America were profitable, partially offset by losses in Africa and Australia. The equity in earnings of affiliates declined at a slower rate than the remainder of the division, reflecting higher stability from certain longer term contracts. We have aggressively reduced staffing and other costs in dealing with the reduced market activity.

The increased revenue noted in the fourth quarter, along with the effect of cost reduction measures, produced income before income taxes of $3,855,000 as compared to $437,000 in the fourth quarter last year.

Energy Division

(in thousands) Fiscal Years Ended January 31,	2010	2009
Revenues	$45,940	$ 46,352
(Loss) before income taxes	(6,393)	(12,401)

Energy revenues decreased 0.9% to $45,940,000 for fiscal 2010, compared to revenues of $46,352,000 for fiscal 2009. Revenue on the forward sales contracts in place increased for the year, although was more than offset by lower transportation revenue for third party gas.

In fiscal 2010, the Company recorded non-cash impairment charges of $21,642,000 for the carrying value of the assets in excess of future net cash flows, and in fiscal 2009, the Company recorded non-cash impairment charges of $26,690,000. The Company also recorded a $2,014,000 non-cash impairment of oil and gas properties in fiscal 2009, related to the Company s exploration project in Chile, begun in 2008. If natural gas prices do not improve or the Company is not able to enter into new forward sales contracts at attractive prices, additional impairments could occur in fiscal 2011. As of January 31, 2010, the remaining net book value of assets subject to impairment was $26,699,000.

During the years ended January 31, 2010 and 2009, we recorded settlement gains, net of attorney fees, of $667,000 and $2,173,000 respectively, related to litigation against former officers of a subsidiary and associated energy production companies.

Excluding the non-cash impairment charges, income before income taxes for the energy division decreased 6.5% to $15,249,000 for fiscal 2010 compared to $16,303,000 for fiscal 2009. The decrease in income before income taxes was primarily due to $2,176,000 of higher depletion based on decreased proved oil and gas reserves and the lower litigation settlement, partially offset by higher contract prices and volume on forward sales contracts in place compared to the prior year, and steps taken to reduce operating costs and increase efficiency in our field operations.

Other

(in thousands) Fiscal Years Ended January 31,	2010	2009
Revenues	$3,783	$5,836
Income before income taxes	308	1,280

Activity in our other specialty operations was down as compared to last year primarily due to contracts in Canada and Africa last year that did not repeat.

Unallocated Corporate Expenses

Corporate expenses not allocated to individual divisions, primarily included in selling, general and administrative expenses, were $28,889,000 and $25,486,000 for fiscal 2010 and 2009, respectively. The increase for the year was due to $4,980,000 in additional expense in fiscal 2010 for settlement of our pension benefit obligations (see Note 11 of the Notes to Consolidated Financial Statements) partially offset by decreased expense for legal and professional fees and compensation related expenses.

Comparison of Fiscal 2009 to Fiscal 2008

Revenues for fiscal 2009 increased $139,789,000, or 16.1%, to $1,008,063,000 compared to $868,274,000 for fiscal 2008. Revenues were up across all primary divisions. A further discussion of results of operations by division is presented below.

Selling, general and administrative expenses increased to $136,687,000 for fiscal 2009 compared to $119,937,000 for fiscal 2008 (13.6% and 13.8% of revenues, respectively). The increase was primarily the result of $7,497,000 in expenses added from acquisitions and start up operations, compensation related expense increases of $3,887,000, with the remainder of the increase spread across various categories.

Depreciation, depletion and amortization increased to $52,840,000 for fiscal 2009 compared to $43,620,000 for fiscal 2008. The increase was primarily the result of increased depletion of $3,232,000 resulting from increases in production of unconventional gas from the Company s energy operations and increased depreciation from property additions and acquisitions in the other divisions.

The Company recorded non-cash impairments to oil and gas properties of $28,704,000 in fiscal 2009, including $26,690,000 of ceiling test impairment in the fourth quarter, as a result of a significant decline in natural gas prices and $2,014,000 related to an exploration project in Chile. There were no impairments in fiscal 2008.

Equity in earnings of affiliates increased to $14,089,000 for fiscal 2009 compared to $8,076,000 for fiscal 2008. The increase reflects strong performance in mineral exploration by affiliates in Latin America, particularly Chile, during most of the fiscal year.

Interest expense decreased to $3,614,000 for fiscal 2009 compared to $8,730,000 for fiscal 2008. The decrease was primarily a result of debt paid off with proceeds from the Company s stock offering in October 2007.

The Company s effective tax rate was 44.8% for fiscal 2009, compared to 44.8% for fiscal 2008. The effective rates in excess of the statutory federal rate were due primarily to the impact of nondeductible expenses and the tax treatment of certain foreign operations.

Water Infrastructure Division

(in thousands)		
Fiscal Years Ended January 31,	2009	2008
Revenues	$766,957	$639,584
Income before income taxes	48,399	42,995

Water infrastructure revenues increased 19.9% to $766,957,000 for fiscal 2009, from $639,584,000 for fiscal 2008. The increase in revenues was partially attributable to incremental revenues of $54,458,000 from the Company s acquisitions and increases of $25,325,000 in water and wastewater treatment plant construction, $20,389,000 in specialty geoconstruction and $9,396,000 in sewer rehabilitation.

Income before income taxes for the water infrastructure division increased 12.6% to $48,399,000 for fiscal 2009, compared to $42,995,000 for fiscal 2008. Included in fiscal 2008 results was $1,626,000 in non-recurring income from the recovery of previously written-off costs associated with a groundwater transfer project in Texas. Excluding this item, the increase in income was primarily attributable to increases in earnings of $3,635,000 in specialty geoconstruction, $2,527,000 in water and wastewater treatment plant construction and $1,135,000 in sewer rehabilitation.

The backlog in the water infrastructure division was $427,863,000 as of January 31, 2009, compared to $408,404,000 as of January 31, 2008.

Mineral Exploration Division

(in thousands)		
Fiscal Years Ended January 31,	2009	2008

Revenues	$188,918	$178,482
Income before income taxes	39,260	37,452

Mineral exploration revenues increased 5.8% to $188,918,000 for fiscal 2009, compared to revenues of $178,482,000 for fiscal 2008. The increase in revenues was primarily attributable to strength in exploration activity in the Company s markets as a result of the relatively high gold and base metal prices in the first three quarters of the year. Revenues decreased in the fourth quarter of fiscal 2009 as mining companies extended holiday mine shutdowns and delayed spending programs in response to tightening credit and economic uncertainty. We expect this revenue trend to continue into next year.

Income before income taxes for the mineral exploration division increased 4.8% to $39,260,000 for fiscal 2009, compared to $37,452,000 for fiscal 2008. Included in income is equity in earnings of affiliates, which increased $6,013,000 over fiscal 2008. Excluding the affiliate earnings, the division s earnings decreased $4,205,000 in earnings for the year, primarily due to the fourth quarter exploration spending slowdowns noted above.

Energy Division

(in thousands) Fiscal Years Ended January 31,	2009	2008
Revenues	$ 46,352	$39,749
(Loss) income before income taxes	(12,401)	13,075

Energy division revenues increased 16.6% to $46,352,000 for fiscal 2009, compared to revenues of $39,749,000 for fiscal 2008. The increase in revenues was primarily attributable to increased production from the Company s unconventional gas properties.

During the fourth quarter of fiscal 2009, the Company completed its annual determination of oil and gas reserves for the Energy division. This determination was made according to SEC guidelines and used year end gas prices. Gas prices at January 31, 2009, used in the determination were $3.29 per Mcf, compared to $7.53 per Mcf used in January 31, 2008. As a result of the lower prices, the expected future cash flows and gas reserve volumes were significantly reduced. Accordingly, in the fourth quarter, the Company recorded a non-cash impairment charge of $26,690,000, or $16,081,000 after income tax, for the carrying value of the assets in excess of future net cash flows.

During fiscal 2009, we also recorded an impairment of oil and gas properties of $2,014,000 related to the Company s exploration project in Chile, begun in 2008. Following initial core testing and further evaluation of infrastructure requirements, it was determined that recovery of our investment was not likely and costs were written off. We also recorded settlement income related to litigation initiated in fiscal 2009 against former officers of a subsidiary and associated energy production companies. During September 2008, the Company entered into a settlement agreement whereby it received certain payments over a period through September 2009. Settlement income of $2,173,000 was recorded in fiscal 2009 for the payments received, net of attorney fees.

Excluding the non-cash impairment charges, income before income taxes for the energy division increased 24.7% to $16,303,000 for fiscal 2009, compared to $13,075,000 for fiscal 2008. The increases were attributable to the settlement income and increased production, partially offset by reduced pricing in the second half of the year for the portion of the division s production which was not covered by forward sales contracts.

Other

(in thousands) Fiscal Years Ended January 31,	2009	2008
Revenues	$5,836	$10,459
Income before income taxes	1,280	3,696

Included in Other for fiscal 2009 and 2008 were revenues of $470,000 and $4,954,000, respectively, associated with contracts to provide consulting and logistical support for international projects in Canada and Africa. Excluding the effects of these activities, the remainder of the operations included in this segment were consistent year over year.

Unallocated Corporate Expenses

Corporate expenses not allocated to individual divisions, primarily included in selling, general and administrative expenses, were $25,486,000 and $21,199,000 for fiscal 2009 and 2008, respectively. The increase for the year was primarily due to compensation related expenses.

Fluctuation in Quarterly Results

The Company historically has experienced fluctuations in its quarterly results arising from the timing of the award and completion of contracts, the recording of related revenues and unanticipated additional costs incurred on projects. The Company s revenues on large, long-term contracts are recognized on a percentage of completion basis for individual contracts based upon the ratio of costs incurred to total estimated costs at completion. Contract price and cost estimates are reviewed periodically as work progresses and adjustments proportionate to the percentage of completion are reflected in contract revenues and gross profit in the reporting period when such estimates are revised. Changes in job performance, job conditions and estimated profitability (including those arising from contract penalty provisions) and final contract settlements may result in revisions to costs and income and are recognized in the period in which the revisions are determined. A significant number of the Company s contracts contain fixed prices and assign responsibility to the Company for cost overruns for the subject projects; as a result, revenues and gross margin may vary from those originally estimated and, depending upon the size of the project, variations from estimated contract performance could affect the Company s operating results for a particular quarter. Many of the Company s contracts are also subject to cancellation by the customer upon short notice with limited or no damages payable to the Company. In addition, adverse weather conditions, natural disasters, force majeure and other similar events can curtail Company operations in various regions of the world throughout the year, resulting in performance delays and increased costs. Moreover, the Company s domestic drilling and construction activities and related revenues and earnings tend to decrease in the winter months when adverse weather conditions interfere with access to project sites; as a result, the Company s revenues and earnings in its second and third quarters tend to be higher than revenues and earnings in its first and fourth quarters. Accordingly, as a result of the foregoing as well as other factors, quarterly results should not be considered indicative of results to be expected for any other quarter or for any full fiscal year. See the Company s Consolidated Financial Statements and Notes thereto.

Inflation

Management does not believe that the Company s operations for the periods discussed have been significantly adversely affected by inflation or changing prices from its suppliers.

Liquidity and Capital Resources

Management exercises discretion regarding the liquidity and capital resource needs of its business segments. This includes the ability to prioritize the use of capital and debt capacity, to determine cash management policies and to make decisions regarding capital expenditures. The Company s primary sources of liquidity have historically been cash from operations, supplemented by borrowings under its credit facilities.

The Company maintains an agreement (the Master Shelf Agreement) whereby it has $50,000,000 of unsecured notes available to be issued before September 15, 2012. At January 31, 2010, the Company has $26,667,000 in notes outstanding under the Master Shelf Agreement. Additionally, the Company holds an unsecured $200,000,000 revolving credit facility (the Credit Agreement) which extends to November 15, 2011. At January 31, 2010, the Company had letters of credits of $19,805,000 and no borrowings outstanding under the Credit Agreement resulting in available capacity of $180,195,000. In anticipation of the expiration of the revolving credit facility in November 2011, the Company expects to begin negotiation of an extension or new credit facility during fiscal 2011.

The Company s Master Shelf Agreement and Credit Agreement each contain certain covenants including restrictions on the incurrence of additional indebtedness and liens, investments, acquisitions, transfer or sale of assets, transactions with affiliates and payment of dividends. These provisions generally allow such activity to occur, subject to specific limitations and continued compliance with financial maintenance covenants. Significant financial maintenance covenants are fixed charge coverage ratio, maximum leverage ratio and minimum tangible net worth. Covenant levels and definitions are consistent between the two agreements. The Company was in compliance with its covenants as of January 31, 2010 and expects to be in compliance in fiscal 2011.

Compliance with the financial covenants is required on a quarterly basis, using the most recent four fiscal quarters. The Company s fixed charge coverage ratio and leverage ratio covenants are based on ratios utilizing adjusted EBITDA and adjusted EBITDAR, as defined in the agreements. Adjusted EBITDA is generally defined as consolidated net income excluding net interest expense, provision for income taxes, gains or losses from extraordinary items, gains or losses from the sale of capital assets, non-cash items including depreciation and amortization, and share-based compensation. Equity in earnings of affiliates is included only to the extent of dividends or distributions received. Adjusted EBITDAR is defined as adjusted EBITDA, plus rent expense. The Company s tangible net worth covenant is based on stockholders equity less intangible assets. All of these measures are considered non-GAAP financial measures and are not intended to be in accordance with accounting principles generally accepted in the United States.

The Company s minimum fixed charge coverage ratio covenant is the ratio of adjusted EBITDAR to the sum of fixed charges. Fixed charges consist of rent expense, interest expense, and principal payments of long-term debt. The Company s leverage ratio covenant is the ratio of total funded indebtedness to adjusted EBITDA. Total funded indebtedness generally consists of outstanding debt, capital leases, unfunded pension liabilities, asset retirement obligations and escrow liabilities. The Company s tangible net worth covenant is measured based on stockholders equity, less intangible assets, as compared to a threshold amount defined in the agreements. The threshold is adjusted over time based on a percentage of net income and the proceeds from the issuance of equity securities.

As of January 31, 2010 and 2009, the Company s actual and required covenant levels were as follows:

(in thousands, except ratio data)	Actual 2010	Required 2010	Actual 2009	Required 2009
Minimum fixed charge coverage ratio	2.23	1.50	4.22	1.50
Maximum leverage ratio	0.42	3.00	0.44	3.00
Minimum tangible net worth	$346,215	$296,266	$340,280	$291,237

The Company s working capital as of January 31, 2010, 2009 and 2008, was $119,649,000, $128,610,000 and $127,696,000, respectively. The decrease at January 31, 2010, is primarily due to increased levels of billings on contracts in advance of revenues recognized.

The Company believes it will have sufficient cash from operations and access to credit facilities to meet the Company s operating cash requirements and to fund its budgeted capital expenditures for fiscal 2011. We do not currently believe we will draw on credit facilities in fiscal 2011, however, we believe our lenders are sufficiently capitalized to meet our needs if required.

The Company is also highly dependent on the availability of surety bonding capacity, particularly in its water infrastructure business. The Company believes it has adequate access through its insurers to meet its business requirements and growth opportunities.

Operating Activities

Cash from operating activities was $93,955,000, $92,026,000 and $80,163,000 for fiscal 2010, 2009 and 2008, respectively. Although operating earnings have declined from the prior year, the Company has been able to efficiently manage its working capital levels and generate additional cash flow.

Investing Activities

The Company s capital expenditures, net of proceeds from disposals, of $44,017,000 for the year ended January 31, 2010, were split between $39,753,000 to maintain and upgrade its construction equipment and $4,264,000 toward the Company s unconventional gas exploration and production, including the construction of gas pipeline infrastructure near the Company s development projects. During the year, the Company spent $14,606,000, net of cash acquired, to complete acquisitions to complement its water infrastructure division. Spending for the Company s unconventional gas operations was reduced significantly in fiscal 2010 as we scaled back production in reaction to lower gas prices available in our market. Should gas prices remain low, we intend to continue to hold back production and spend capital primarily to meet obligations under our leases.

The Company s capital expenditures, net of proceeds from disposals, of $79,851,000 for the year ended January 31, 2009, were split between $50,244,000 to maintain and upgrade its construction equipment and $29,607,000 toward the Company s expansion into unconventional gas exploration and production, including the construction of gas pipeline infrastructure near the Company s development projects. During the year, the Company spent $7,103,000 to complete acquisitions to complement its water infrastructure division.

The Company s capital expenditures, net of proceeds from disposals, of $70,037,000 for the year ended January 31, 2008, were more heavily weighted toward its water infrastructure and minerals divisions rather than unconventional gas exploration and production. Expenditures were made in those two divisions during the year to sustain capacity and improve efficiency of the equipment. Unconventional gas expenditures declined to $29,193,000 as the Company maintained its U.S. operations while carefully considering its expansion efforts on its exploration concession in Chile. Also during the year, the Company spent $22,740,000 to complete acquisitions to complement its water infrastructure division.

Financing Activities

The Company had no borrowings under its revolving credit facilities during the years ended January 31, 2010 and 2009, financing the business from operations and available cash. The Company made scheduled principal payments on the Senior Notes of $13,333,000 in July 2009 and $6,667,000 in September 2009.

In October 2007, the Company completed a public offering of its common stock. The offering produced net proceeds of approximately $160 million, which were used to repay the then outstanding borrowings on the Company s revolving bank credit facility and to build funds for potential future acquisitions and general corporate purposes

Contractual Obligation and Commercial Commitments

The Company s contractual obligations and commercial commitments as of January 31, 2010, are summarized as follows:

(in thousands)	Payments/Expiration by Period				
	Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
Contractual Obligations and Other Commercial Commitments					
Credit Agreement principal payments	$	$	$	$	$
Senior Notes principal payments	26,667	20,000	6,667		
Interest payments	3,011	2,291	720		
Software financing obligations	640	482	158		
Operating leases	30,414	11,960	13,652	4,802	
Mineral interest obligations	671	115	381	164	11
Income tax uncertainties	2,149	2,149			
Total cash contractual obligations	63,552	36,997	21,578	4,966	11
Standby letters of credit	19,805	19,805			
Asset retirement obligations	1,498				1,498
Total contractual obligations and commercial commitments	$84,855	$56,802	$21,578	$4,966	$1,509

The Company expects to meet its cash contractual obligations in the ordinary course of operations, and that the standby letters of credit will be renewed in connection with its annual insurance renewal process. Interest is payable on the Credit Agreement at variable interest rates equal to, at the Company s option, a LIBOR rate plus 0.75% to 2.00%, or a base rate, as defined in the Credit Agreement plus up to 0.50%, depending on the Company s leverage ratio. Interest is payable on the Senior Notes at fixed interest rates of 6.05% and 5.40% (see Note 12 of the Notes to Consolidated Financial Statements). Interest payments have been included in the table above based only on outstanding balances on the Senior Notes as of January 31, 2010.

The Company has income tax uncertainties in the amount of $10,150,000 at January 31, 2010, that are classified as non-current on the Company s balance sheet as resolution of these matters is expected to take more than a year. The ultimate timing of resolution of these items is uncertain, and accordingly the amounts have not been included in the table above.

The Company incurs additional obligations in the ordinary course of operations. These obligations, including but not limited to, income tax payments and pension fundings are expected to be met in the normal course of operations.

Critical Accounting Policies and Estimates

Management s Discussion and Analysis of Financial Condition and Results of Operations discusses the Company s Consolidated Financial Statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires management 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 revenues and expenses during the reporting period. On an on-going basis, management evaluates its estimates and judgments, which are based on historical experience and on various other factors that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates under different assumptions or conditions.

Our accounting policies are more fully described in Note 1 of the Notes to Consolidated Financial Statements, located in Item 8 of this Form 10-K. We believe that the following represent our more critical estimates and assumptions used in the preparation of our Consolidated Financial Statements, although not all inclusive.

Revenue Recognition Revenues are recognized on large, long-term construction contracts meeting the criteria of Accounting Standards Codification (ASC) Topic 605-35 Construction-Type and Production-Type Contracts (ASC Topic 605-35), using the percentage-of-completion method based upon the ratio of costs incurred to total estimated costs at completion. Contract price and cost estimates are reviewed periodically as work progresses and adjustments proportionate to the percentage of completion are reflected in contract revenues in the reporting period when such estimates are revised. Changes in job performance, job conditions and estimated profitability, including those arising from contract penalty provisions, change orders and final contract settlements may result in revisions to costs and income and are recognized in the period in which the revisions are determined. As allowed by ASC Topic 605-35, revenue is recognized on smaller, short-term construction contracts using the completed contract method. Provisions for estimated losses on uncompleted construction contracts are made in the period in which such losses are determined.

Revenues for direct sales of equipment and other ancillary products not provided in conjunction with the performance of construction contracts are recognized at the date of delivery to, and acceptance by, the customer. Provisions for estimated warranty obligations are made in the period in which the sales occur.

Contracts for the Company s mineral exploration drilling services are billable based on the quantity of drilling performed. Thus, revenues for these drilling contracts are recognized on the basis of actual footage or meterage drilled.

Revenues for the sale of oil and gas by the Company s energy division are recognized on the basis of volumes sold at the time of delivery to an end user or an interstate pipeline, net of amounts attributable to royalty or working interest holders.

The Company s revenues are presented net of taxes imposed on revenue-producing transactions with its customers, such as, but not limited to, sales, use, value-added and some excise taxes.

Oil and Gas Properties and Mineral Interests The Company follows the full cost method of accounting for oil and gas properties. Under this method, all productive and nonproductive costs incurred in connection with the exploration for and development of oil and gas reserves are capitalized. Such capitalized costs include lease acquisition, geological and geophysical work, delay rentals, drilling, completing and equipping oil and gas wells, and salaries, benefits and other internal salary-related costs directly attributable to these activities. Costs associated with production and general corporate activities are expensed in the period incurred. Normal dispositions of oil and gas properties are accounted for as adjustments of capitalized costs, with no gain or loss recognized. Capitalized costs are depleted based on units of production.

The Company is required to review the carrying value of its oil and gas properties under the full cost accounting rules of the SEC (the Ceiling Test). The ceiling limitation is the estimated after-tax future net revenues from proved oil and gas properties discounted at 10%, plus the cost of properties not subject to amortization. If the net book value of our oil and gas properties, less related deferred income taxes, is in excess of the calculated ceiling, the excess must be written off as an expense. In accordance with changes in the SEC rules, beginning at our fiscal 2010 year end, application of the Ceiling Test requires pricing future revenues at the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of reporting period, unless prices are defined by contractual arrangements such as the Company s fixed-price physical delivery forward sales contracts. Considerations of the Ceiling Test prior to the fiscal 2010 year end used the period end price, as adjusted for contractual arrangements. Unproved oil and gas properties are not amortized, but are assessed for impairment either individually or on an aggregated basis using a comparison of the carrying values of the unproved properties to net future cash flows. See Note 4 for a discussion of the impairments recorded.

Reserve Estimates The Company s estimates of natural gas reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing natural gas prices, future operating costs, severance, ad valorem and excise taxes, development costs and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected there from may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Company s oil and gas properties and the rate of depletion of the oil and gas properties. Actual production, revenues and expenditures with respect to the Company s reserves will likely vary from estimates, and such variances may be material.

Goodwill and Other Intangibles The Company accounts for goodwill and other intangible assets in accordance with ASC Topic 350, Intangibles Goodwill and Other. Other intangible assets primarily consist of trademarks, customer-related intangible assets and patents obtained through business acquisitions. Amortizable intangible assets are being amortized over their estimated useful lives, which range from two to 40 years.

The impairment evaluation for goodwill is conducted annually or more frequently if events or changes in circumstances indicate that an asset might be impaired. The evaluation is performed by using a two-step process. In the first step, the fair value of each reporting unit is compared with the carrying amount of the reporting unit, including goodwill. The estimated fair value of the reporting unit is generally determined on the basis of discounted future cash flows. If the estimated fair value of the reporting unit is less than the carrying amount of the reporting unit, then a second step must be completed in order to determine the amount of the goodwill impairment that should be recorded. In the second step, the implied fair value of the reporting unit s goodwill is determined by allocating the reporting unit s fair value to all of its assets and liabilities other than goodwill (including any unrecognized intangible assets) in a manner similar to a purchase price allocation. The resulting implied fair value of the goodwill that results from the application of this second step is then compared to the carrying amount of the goodwill and an impairment charge is recorded for the difference.

The impairment evaluation of the carrying amount of intangible assets with indefinite lives is conducted annually or more frequently if events or changes in circumstances indicate that an asset might be impaired. The evaluation is performed by comparing the carrying amount of these assets to their estimated fair value. If the estimated fair value is less than the carrying amount of the intangible assets with indefinite lives, then an impairment charge is recorded to reduce the asset to its estimated fair value. The estimated fair value is generally determined on the basis of discounted future cash flows.

The assumptions used in the estimate of fair value are generally consistent with the past performance of each reporting unit and are also consistent with the projections and assumptions that are used in current operating plans. Such assumptions are subject to change as a result of changing economic and competitive conditions.

Other Long-lived Assets In the event of an indication of possible impairment, the Company evaluates the fair value and future benefits of long-lived assets, including the Company s gas transportation facilities and equipment, by performing an analysis of the anticipated future net cash flows of the related long-lived assets and reducing their carrying value by the excess, if any, of the result of such calculation. The Company believes at this time that the carrying values and useful lives of its long-lived assets continue to be appropriate.

Accrued Insurance Expense The Company maintains insurance programs where it is responsible for a certain amount of each claim up to a retention limit. Estimates are recorded for health and welfare, property and casualty insurance costs that are associated with these programs. These costs are estimated based on actuarially determined projections of future payments under these programs. Should a greater amount of claims occur compared to what was estimated or medical costs increase beyond what was anticipated, reserves recorded may not be sufficient and additional costs to the Consolidated Financial Statements could be required.

Costs estimated to be incurred in the future for employee health and welfare benefits, property, workers compensation and casualty insurance programs resulting from claims which have occurred are accrued currently. Under the terms of the Company s agreement with the various insurance carriers administering these claims, the Company is not required to remit the total premium until the claims are actually paid by the insurance companies. These costs are not expected to significantly impact liquidity in future periods.

Income Taxes Income taxes are provided using the asset/liability method, in which deferred taxes are recognized for the tax consequences of temporary differences between the financial statement carrying amounts and tax bases of existing assets and liabilities. Deferred tax assets are reviewed for recoverability and valuation allowances are provided as necessary. Provision for U.S. income taxes on undistributed earnings of foreign subsidiaries and affiliates is made only on those amounts in excess of funds considered to be invested indefinitely.

Litigation and Other Contingencies The Company is involved in litigation incidental to its business, the disposition of which is not expected to have a material effect on the Company s financial position or results of operations. It is possible, however, that future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company s assumptions related to these proceedings. The Company accrues its best estimate of the probable cost for the resolution of legal claims. Such estimates are developed in consultation with counsel handling these matters and are based upon a combination of litigation and settlement strategies. To the extent additional information arises or the Company s strategies change, it is possible that the Company s estimate of its probable liability in these matters may change.

New Accounting Pronouncements See Note 18 of the Notes to Consolidated Financial Statements for a discussion of new accounting pronouncements and their impact on the Company.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The principal market risks to which the Company is exposed are interest rate risk on variable rate debt, foreign exchange rate risk that could give rise to translation and transaction gains and losses and fluctuations in the price of natural gas.

The Company centrally manages its debt portfolio considering overall financing strategies and tax consequences. A description of the Company s debt is included in Note 12 of the Notes to Consolidated Financial Statements of this Form 10-K. As of January 31, 2010, an instantaneous change in interest rates of one percentage point would not change the Company s annual interest expense as we have no variable rate debt outstanding.

Operating in international markets involves exposure to possible volatile movements in currency exchange rates. Currently, the Company s primary international operations are in Australia, Africa, Mexico, Canada, Brazil and Italy. The operations are described in Notes 1 and 17 to the Consolidated Financial Statements. The Company s affiliates also operate in South America and Mexico (see Note 3 of the Notes to Consolidated Financial Statements). The majority of the Company s contracts in Africa and Mexico are U.S. dollar-based, providing a natural reduction in exposure to currency fluctuations. The Company also may utilize various hedge instruments, primarily foreign currency option contracts, to manage the exposures associated with fluctuating currency exchange rates (see Note 13 of the Notes to Consolidated Financial Statements). As of January 31, 2010, the Company held option contracts with an aggregate U.S. dollar notional value of $7,600,000, which are intended to hedge exposure to Australian dollar fluctuations through January 31, 2011.

As currency exchange rates change, translation of the income statements of the Company s international operations into U.S. dollars may affect year-to-year comparability of operating results. We estimate that a 10% change in foreign exchange rates would impact income before income taxes by approximately $131,000, $585,000 and $511,000 for the years ended January 31, 2010, 2009 and 2008, respectively. This represents approximately 10% of the income before income taxes of international businesses after adjusting for primarily U.S. dollar-based operations. This quantitative measure has inherent limitations, as it does not take into account any governmental actions, changes in customer purchasing patterns or changes in the Company s financing and operating strategies.

Foreign exchange gains and losses in the Company s Consolidated Statements of Income reflect transaction gains and losses and translation gains and losses from the Company s Mexican and African operations which use the U.S. dollar as their functional currency. Net foreign exchange (losses) gains for the years ended January 31, 2010, 2009 and 2008, were ($802,000), $91,000 and ($430,000), respectively.

The Company is also exposed to fluctuations in the price of natural gas, which affect the sale of the energy division s unconventional gas production. The price of natural gas is volatile and the Company has entered into fixed-price physical delivery forward sales contracts covering a portion of its production to manage price fluctuations and to achieve a more predictable cash flow. As of January 31, 2010, the Company held contracts for physical delivery of 885,000 million British Thermal Units (MMBtu) of natural gas through March 31, 2010, at prices ranging from $7.68 to $10.67 per MMBtu through March 2010. The estimated fair value of such contracts at January 31, 2010, was $2,831,000. Due to continued low prices in the forward sales markets, the Company has not yet extended its forward sales contracts beyond March 2010. We intend to continue monitoring forward sales prices and will reevaluate our forward sales commitments accordingly over the course of fiscal 2011.

We estimate that a 10% change in the price of natural gas would have impacted income before taxes by approximately $225,000 for the year ended January 31, 2010, exclusive of any potential impact on the Ceiling Test computation.

Item 8. Financial Statements and Supplementary Data
Index to Consolidated Financial Statements and Financial Statement Schedules

All other schedules have been omitted because they are not applicable or not required as the required information is included in the Consolidated Financial Statements of the Company or the Notes thereto.

Statement of Management Responsibility

The Consolidated Financial Statements of Layne Christensen Company and subsidiaries (the Company) have been prepared in conformity with accounting principles generally accepted in the United States. The integrity and objectivity of the data in these financial statements are the responsibility of management, as is all other information included in the Annual Report on Form 10-K. Management believes the information presented in the Annual Report is consistent with the financial statements, and the financial statements do not contain material misstatements due to fraud or error. Where appropriate, the financial statements reflect management s best estimates and judgments.

Management is also responsible for maintaining a system of internal accounting controls with the objectives of providing reasonable assurance that the Company s assets are safeguarded against material loss from unauthorized use or disposition, and that authorized transactions are properly recorded to permit the preparation of accurate financial data. However, limitations exist in any system of internal controls based on a recognition that the cost of the system should not exceed its benefits. The Company believes its system of accounting controls, of which its internal auditing function is an integral part, accomplishes the stated objectives.

The Audit Committee of the Board of Directors, composed of outside directors, meets periodically with management, the Company s independent accountants and internal auditors to review matters related to the Company s financial statements, internal audit activities, internal accounting controls and nonaudit services provided by the independent accountants. The independent accountants and internal auditors have full access to the Audit Committee and meet with it, both with and without management present, to discuss the scope and results of their audits, including internal controls, audit and financial matters.

/s/ A. B. Schmitt	*/s/ Jerry W. Fanska*
Andrew B. Schmitt	Jerry W. Fanska
President and	Senior Vice President and
Chief Executive Officer	Chief Financial Officer

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Layne Christensen Company
Mission Woods, Kansas

We have audited the accompanying consolidated balance sheets of Layne Christensen Company and subsidiaries (the Company) as of January 31, 2010 and 2009, and the related consolidated statements of income, stockholders equity, and cash flows for each of the three years in the period ended January 31, 2010. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Layne Christensen Company and subsidiaries at January 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended January 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for oil and gas reserve estimation and related required disclosures on January 31, 2010, with the implementation of new accounting guidance.

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 January 31, 2010, 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 April 1, 2010, expressed an unqualified opinion on the Company s internal control over financial reporting.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
April 1, 2010

Layne Christensen Company and Subsidiaries
Consolidated Balance Sheets
(in thousands, except per share data)

January 31,	2010	2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 84,450	$ 67,165
Customer receivables, less allowance of $7,425 and $7,878, respectively	106,056	116,234
Costs and estimated earnings in excess of billings on uncompleted contracts	83,712	63,638
Inventories	25,637	31,329
Deferred income taxes	18,324	16,561
Income taxes receivable	3,761	6,806
Restricted deposits current	1,415	774
Other	6,996	10,063
Total current assets	330,351	312,570
Property and equipment:		
Land	12,056	8,586
Buildings	34,539	27,209
Machinery and equipment	378,868	336,166
Gas transportation facilities and equipment	40,748	39,825
Oil and gas properties	95,252	92,497
Mineral interests in oil and gas properties	21,939	21,248
	583,402	525,531
Less accumulated depreciation and depletion	(350,630)	(278,786)
Net property and equipment	232,772	246,745
Other assets:		
Investment in affiliates	44,073	40,973
Goodwill	92,532	90,029
Other intangible assets, net	19,649	21,002
Restricted deposits long term	3,151	1,155
Other	8,427	6,883
Total other assets	167,832	160,042
	$ 730,955	$ 719,357
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 87,818	$ 62,575
Current maturities of long term debt	20,000	20,000
Accrued compensation	33,572	36,252

Accrued insurance expense	9,255	9,173
Other accrued expenses	16,779	17,626
Acquisition escrow obligation current	1,415	824
Income taxes payable	4,219	3,254
Billings in excess of costs and estimated earnings on uncompleted contracts	37,644	34,256
Total current liabilities	210,702	183,960
Noncurrent and deferred liabilities:		
Long-term debt	6,667	26,667
Accrued insurance expense	10,759	9,947
Deferred income taxes	17,761	29,063
Acquisition escrow obligation long term	3,151	1,155
Other	15,042	12,468
Total noncurrent and deferred liabilities	53,380	79,300
Contingencies		
Stockholders equity:		
Common stock, par value $.01 per share, 30,000 shares authorized, 19,435 and 19,383 shares issued and outstanding, respectively	194	194
Capital in excess of par value	342,952	337,528
Retained earnings	129,718	128,353
Accumulated other comprehensive loss	(6,066)	(10,053)
Total Layne Christensen Company stockholders equity	466,798	456,022
Noncontrolling interest	75	75
Total equity	466,873	456,097
	$ 730,955	$ 719,357

See Notes to Consolidated Financial Statements.

Layne Christensen Company and Subsidiaries
Consolidated Statements of Income
(in thousands, except per share data)

Years Ended January 31,	2010	2009	2008
Revenues	$ 866,417	$1,008,063	$ 868,274
Cost of revenues (exclusive of depreciation, depletion, amortization and impairment shown below)	(661,552)	(756,083)	(638,003)
Selling, general and administrative expense	(128,244)	(136,687)	(119,937)
Depreciation, depletion and amortization	(57,679)	(52,840)	(43,620)
Impairment of oil and gas properties	(21,642)	(28,704)	
Litigation settlement gains	3,495	2,173	
Equity in earnings of affiliates	8,198	14,089	8,076
Interest expense	(2,734)	(3,614)	(8,730)
Other income, net	199	1,041	1,229
Income before income taxes	6,458	47,438	67,289
Income tax expense	(5,093)	(21,266)	(30,178)
Net income	1,365	26,172	37,111
Net loss attributable to noncontrolling interest		362	145
Net income attributable to Layne Christensen Company	$ 1,365	$ 26,534	$ 37,256
Basic income per share	$ 0.07	$ 1.38	$ 2.23
Diluted income per share	$ 0.07	$ 1.37	$ 2.20
Weighted average shares outstanding basic	19,328	19,191	16,670
Dilutive stock options and unvested shares	94	195	268
Weighted average shares outstanding diluted	19,422	19,386	16,938

See Notes to Consolidated Financial Statements.

Layne Christensen Company and Subsidiaries
Consolidated Statements of Stockholders Equity

(in thousands, except share data)	Common Stock Shares	Common Stock Amount	Capital In Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Layne Christensen Company Stockholders Equity	Noncontrolling Interest	Total
Balance, February 1, 2007	15,517,724	$155	$149,187	$ 64,145	$ (8,453)	$205,034	$	$205,034
Comprehensive income:								
Net income (loss)				37,256		37,256	(145)	37,111
Other comprehensive income:								
Foreign currency translation adjustments, net of income tax benefit of $424					760	760		760
Comprehensive income						38,016		37,871
Issuance of nonvested shares	73,863	1	(1)					
Cumulative effect of adoption of new tax guidance				465		465		465
Change in unrecognized pension liability, net of income tax expense of $445					706	706		706
Proceeds from public offering, net	3,105,000	31	159,848			159,879		159,879
Issuance of stock for acquisition of business	249,023	3	10,979			10,982		10,982
Issuance of stock upon exercise of	215,106	2	2,902			2,904		2,904

options								
Income tax benefit on exercise of options			2,360			2,360		2,360
Shared-based compensation			3,026			3,026		3,026
Contribution of noncontrolling interest							543	543
Balance, January 31, 2008	19,160,716	$192	$328,301	$101,866	$ (6,987)	$423,372	$ 398	$423,770
Comprehensive income:								
Net income (loss)				26,534		26,534	(362)	26,172
Comprehensive income:								
Foreign currency translation adjustments, net of income tax expense of $844					(2,549)	(2,549)		(2,549)
Change in unrealized loss on foreign exchange contracts, net of income tax benefit of $62					(96)	(96)		(96)
Change in unrecognized pension liability, net of income tax benefits of $271					(421)	(421)		(421)
Comprehensive income						23,468		23,106
Issuance of nonvested shares	38,584							
Treasury stock purchased and subsequently cancelled	(5,357)		(245)			(245)		(245)
Cumulative effect of adoption of new pension guidance				(47)		(47)		(47)
	189,033	2	3,321			3,323		3,323

Issuance of stock upon exercise of options								
Income tax benefit on exercise of options			2,067			2,067		2,067
Share-based compensation			4,084			4,084		4,084
Contribution of noncontrolling interest							39	39
Balance, January 31, 2009	19,382,976	$194	$337,528	$128,353	$(10,053)	$456,022	$ 75	$456,097
Comprehensive income:								
Net income				1,365		1,365		1,365
Comprehensive income:								
Foreign currency translation adjustments, net of income tax expense of $1,324					2,936	2,936		2,936
Change in unrealized loss on foreign exchange contracts, net of income tax expense of $22					34	34		34
Change in unrecognized pension liability, net of income tax benefit of $650					1,017	1,017		1,017
Comprehensive income						5,352		5,352
Issuance of nonvested shares	12,771							
Treasury stock purchased and subsequently cancelled	(5,374)		(113)			(113)		(113)
Issuance of stock upon exercise of options	32,159		524			524		524

Income tax benefit on exercise of options			83			83		83
Income tax deficiency upon vesting of restricted shares			(191)			(191)		(191)
Share-based compensation			4,841			4,841		4,841
Issuance of stock for purchase price adjustments	12,677		280			280		280
Balance, January 31, 2010	19,435,209	$194	$342,952	$129,718	$ (6,066)	$466,798	$ 75	$466,873

See Notes to Consolidated Financial Statements.

Layne Christensen Company and Subsidiaries
Consolidated Statements of Cash Flows

(in thousands) Years Ended January 31,	2010	2009	2008
Cash flow from operating activities:			
Net income	$ 1,365	$ 26,172	$ 37,111
Adjustments to reconcile net income to cash from operations:			
Depreciation, depletion and amortization	57,679	52,840	43,620
Deferred income taxes	(12,968)	3,166	2,364
Equity in earnings of affiliates	(8,198)	(14,089)	(8,076)
Dividends received from affiliates	5,098	2,951	2,521
Gain on disposal of property and equipment	(147)	(30)	(671)
Impairment of oil and gas properties	21,642	28,704	
Non-cash litigation settlement	(2,868)		
Share-based compensation	4,841	4,084	3,026
Share-based compensation excess tax benefits	(75)	(1,911)	(2,313)
Changes in current assets and liabilities, (exclusive of effects of acquisitions):			
(Increase) decrease in customer receivables	25,951	13,735	(9,616)
Increase in costs and estimated earnings in excess of billings on uncompleted contracts	(4,770)	(1,531)	(9,205)
(Increase) decrease in inventories	6,128	(10,867)	(1,788)
(Increase) decrease in other current assets	4,279	(4,949)	602
Increase (decrease) in accounts payable and accrued expenses	(11,760)	(8,478)	27,512
Increase (decrease) in billings in excess of costs and estimated earnings on uncompleted contracts	7,845	2,615	(2,648)
Other, net	(87)	(386)	(2,276)
Cash from operating activities	93,955	92,026	80,163
Cash flow used in investing activities:			
Additions to property and equipment	(40,561)	(51,416)	(44,177)
Additions to gas transportation facilities and equipment	(923)	(6,739)	(5,327)
Additions to oil and gas properties	(2,649)	(19,786)	(18,216)
Additions to mineral interests in oil and gas properties	(692)	(3,082)	(5,650)
Payment of cash purchase price adjustment on prior year acquisitions	(1,349)	(33)	(2,270)
Proceeds from disposal of property and equipment	808	1,172	3,333
Acquisition of businesses, net of cash acquired	(13,257)	(7,070)	(20,470)
Deposit of cash into restricted accounts		(15,200)	(2,075)
Release of cash from restricted accounts	515	16,126	9,627
Distribution of restricted cash for prior year acquisition	(515)	(926)	(9,627)
Cash used in investing activities	(58,623)	(86,954)	(94,852)

Cash flow from financing activities:			
Borrowings under revolving credit facilities			483,800
Repayments under revolving credit facilities			(575,400)
Repayments of long-term debt	(20,000)	(13,333)	
Proceeds from public offering of common stock, net of issuance costs			159,879
Issuances of common stock	524	3,323	2,904
Excess tax benefit on exercise of share-based instruments	75	1,911	2,313
Purchases of treasury stock	(113)	(245)	
Contribution by noncontrolling interest		39	543
Cash from (used in) financing activities	(19,514)	(8,305)	74,039
Effects of exchange rate changes on cash	1,467	(2,670)	711
Net increase (decrease) in cash and cash equivalents	17,285	(5,903)	60,061
Cash and cash equivalents at beginning of year	67,165	73,068	13,007
Cash and cash equivalents at end of year	$ 84,450	$ 67,165	$ 73,068

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

(1) Summary of Significant Accounting Policies

Description of Business Layne Christensen Company and subsidiaries (together, the Company) provide drilling and construction services and related products in two principal markets: water infrastructure and mineral exploration, as well as being a producer of unconventional natural gas for the energy market. The Company operates throughout North America as well as in Africa, Australia, Europe and Brazil. Its customers include municipalities, investor-owned water utilities, industrial companies, global mining companies, consulting and engineering firms, heavy civil construction contractors, oil and gas companies and, to a lesser extent, agribusiness. In mineral exploration, the Company has ownership interest in certain foreign affiliates operating in South America, with facilities in Chile and Peru (see Note 3).

Fiscal Year References to years are to the fiscal years then ended.

Investment in Affiliated Companies Investments in affiliates (20% to 50% owned) in which the Company has the ability to exercise significant influence over operating and financial policies are accounted for by the equity method.

Principles of Consolidation The Consolidated Financial Statements include the accounts of the Company and its majority-owned subsidiaries. Intercompany transactions have been eliminated. Financial information for the Company s affiliates and certain foreign subsidiaries is reported in the Company s Consolidated Financial Statements with a one-month lag in reporting periods. The Company has evaluated subsequent events through the time of the filing of these Consolidated Financial Statements.

Use of Estimates in Preparing Financial Statements The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Foreign Currency Transactions and Translation The cash flows and financing activities of the Company s Mexican and African operations are primarily denominated in the U.S. dollar. Accordingly, these operations use the U.S. dollar as their functional currency and remeasure monetary assets and liabilities at year-end exchange rates while nonmonetary items are remeasured at historical rates. Income and expense accounts are remeasured at exchange rates that approximate the weighted average of the prevailing exchange rates in effect during the year, except for depreciation, certain cost of revenues and selling expenses which are translated at historical rates. Gains or losses from changes in exchange rates are recognized in consolidated income in the year of occurrence.

Other foreign subsidiaries and affiliates use local currencies as their functional currency. Assets and liabilities have been remeasured to U.S. dollars at year-end exchange rates. Income and expense items have been translated at exchange rates which approximate the weighted average of the rates prevailing during each year. Translation adjustments are reported as a separate component of accumulated other comprehensive income (loss).

Net foreign currency transaction gains (losses) for 2010, 2009 and 2008 were ($802,000), $91,000 and ($430,000), respectively, and are recorded in other income (expense) in the accompanying consolidated statements of income.

Revenue Recognition Revenues are recognized on large, long-term construction contracts meeting the criteria of Accounting Standards Codification (ASC) Topic 605-35 Construction-Type and Production-Type Contracts (ASC Topic 605-35), using the percentage-of-completion method based upon the ratio of costs incurred to total estimated costs at completion. Contract price and cost estimates are reviewed periodically as work progresses and adjustments proportionate to the percentage of completion are reflected in contract revenues in the reporting period when such estimates are revised. Changes in job performance, job conditions and estimated profitability, including those arising from contract penalty provisions, change orders and final contract settlements may result in revisions to costs and income and are recognized in the period in which the revisions are determined. Contracts for the Company s mineral exploration drilling services are billable based on the quantity of drilling performed and revenues for these drilling contracts are recognized on the basis of actual footage or meterage drilled. As allowed by ASC Topic 605-35, revenue is recognized on smaller, short-term construction contracts using the completed contract method. Provisions for estimated losses on uncompleted construction contracts are made in the period in which such losses are determined.

Revenues for direct sales of equipment and other ancillary products not provided in conjunction with the performance of construction contracts are recognized at the date of delivery to, and acceptance by, the customer. Provisions for estimated warranty obligations are made in the period in which the sales occur.

Revenues for the sale of oil and gas by the Company s energy division are recognized on the basis of volumes sold at the time of delivery to an end user or an interstate pipeline, net of amounts attributable to royalty or working interest holders.

The Company s revenues are presented net of taxes imposed on revenue-producing transactions with its customers, such as, but not limited to, sales, use, value-added, and some excise taxes.

Inventories The Company values inventories at the lower of cost (first-in, first-out) or market. Allowances are recorded for inventory considered to be excess or obsolete. Inventories consist primarily of parts and supplies.

Property and Equipment and Related Depreciation Property and equipment (including major renewals and improvements) are recorded at cost. Depreciation is provided using the straight-line method. Depreciation expense was $42,059,000, $39,432,000 and $33,933,000 in 2010, 2009 and 2008, respectively. The lives used for the items within each property classification are as follows:

	Years
Buildings	15 - 35
Machinery and equipment	3 - 10
Gas transportation facilities and equipment	15

Oil and Gas Properties and Mineral Interests The Company follows the full-cost method of accounting for oil and gas properties. Under this method, all productive and nonproductive costs incurred in connection with the exploration for and development of oil and gas reserves are capitalized. Such capitalized costs include lease acquisition, geological and geophysical work, delay rentals, drilling, completing and equipping oil and gas wells, and salaries, benefits and other internal salary-related costs directly attributable to these activities. Costs associated with production and general corporate activities are expensed in the period incurred. Normal dispositions of oil and gas properties are accounted for as adjustments of capitalized costs, with no gain or loss recognized. Capitalized costs are depleted based on units of production. Depletion expense was $13,992,000, $11,816,000 and $8,504,000 in 2010, 2009 and 2008, respectively.

The Company is required to review the carrying value of its oil and gas properties under the full cost accounting rules of the SEC (the Ceiling Test). The ceiling limitation is the estimated after-tax future net revenues from proved oil and gas properties discounted at 10%, plus the cost of properties not subject to amortization. If our net book value of oil and gas properties, less related deferred income taxes, is in excess of the calculated ceiling, the excess must be written off as an expense. Beginning with our fiscal 2010 year end, application of the Ceiling Test requires pricing future revenues at the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period to the end of the reporting period, unless prices are defined by contractual arrangements such as the Company s fixed-price physical delivery forward sales contracts. Considerations of the Ceiling Test prior to fiscal 2010 year end used the period end price, as adjusted for contractual arrangements. Unproved oil and gas properties are not amortized, but are assessed for impairment either individually or on an aggregated basis using a comparison of the carrying values of the unproved properties to net future cash flows. See Note 4 for a discussion of the impairments recorded.

Reserve Estimates The Company s estimates of natural gas reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing natural gas prices, future operating costs, severance, ad valorem and excise taxes, development costs and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected there from may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Company s oil and gas properties and the rate of depletion of the oil and gas properties. Actual production, revenues and expenditures with respect to the Company s reserves will likely vary from estimates, and such variances may be material.

On December 31, 2008, the SEC adopted the final rules and interpretations updating its oil and gas reserves reporting requirements. Many of the revisions are updates to definitions in the existing oil and gas rules to make them consistent with the Petroleum Resource Management System, which is a widely accepted set of evaluation guidelines that are designed to support assessment processes throughout the resource asset lifecycle. These guidelines were prepared by the Society of Petroleum Engineers (SPE) Oil and Gas Reserves Committee with cooperation from many industry organizations. One of the key changes to the previous SEC rules relates to using a 12-month average commodity price to calculate the value of proved reserves versus the prior method of using year-end prices. Other key revisions include the ability to include nontraditional resources in reserves, the use of new technology for determining reserves, the opportunity to establish proved undeveloped reserves without the requirement of an adjacent producing well and permitting disclosure of probable and possible reserves. The amended disclosure requirements are effective for registration statements filed after January 1, 2010, and for annual reports for fiscal years ending on or after December 31, 2009. Early adoption was not permitted. The new SEC rules, which were incorporated into ASC Topic 932, were effective for this filing and have been reflected herein as a change in accounting principle that is inseparable from a change in accounting estimate.

Goodwill and Intangibles The Company accounts for goodwill and other intangible assets in accordance with ASC Topic 350, Intangibles Goodwill and Other. Other intangible assets primarily consist of trademarks, customer-related intangible assets and patents obtained through business acquisitions. Amortizable intangible assets are being amortized over their estimated useful lives, which range from two to 40 years.

The impairment evaluation for goodwill is conducted annually, or more frequently if events or changes in circumstances indicate that an asset might be impaired. The evaluation is performed by using a two-step process. In the first step, the fair value of each reporting unit is compared with the carrying amount of the reporting unit, including goodwill. The estimated fair value of the reporting unit is generally determined on the basis of discounted future cash flows. If the estimated fair value of the reporting unit is less than the carrying amount of the reporting unit, then a second step must be completed in order to determine the amount of the goodwill impairment that should be recorded. In the second step, the implied fair value of the reporting unit s goodwill is determined by allocating the reporting unit s fair value to all of its assets and liabilities other than goodwill (including any unrecognized intangible assets) in a manner similar to a purchase price allocation. The resulting implied fair value of the goodwill that results from the application of this second step is then compared to the carrying amount of the goodwill and an impairment charge is recorded for the difference.

The impairment evaluation of the carrying amount of intangible assets with indefinite lives is conducted annually, or more frequently if events or changes in circumstances indicate that an asset might be impaired. The evaluation is performed by comparing the carrying amount of these assets to their estimated fair value. If the estimated fair value is less than the carrying amount of the intangible assets with indefinite lives, then an impairment charge is recorded to reduce the asset to its estimated fair value. The estimated fair value is generally determined on the basis of discounted future cash flows.

The assumptions used in the estimate of fair value are generally consistent with the past performance of each reporting unit and are also consistent with the projections and assumptions that are used in current operating plans. Such assumptions are subject to change as a result of changing economic and competitive conditions.

Other Long-Lived Assets In the event of an indication of possible impairment, the Company evaluates the carrying value of long-lived assets, including the Company s gas transportation facilities and equipment, by performing an analysis of the anticipated future net cash flows of the related long-lived assets and reducing their carrying value by the excess, if any, of the result of such calculation. The Company believes at this time that the carrying value and useful lives of its long-lived assets continue to be appropriate.

Cash and Cash Equivalents The Company considers investments with an original maturity of three months or less when purchased to be cash equivalents. The Company s cash equivalents are subject to potential credit risk. The Company s cash management and investment policies restrict investments to investment grade, highly liquid securities. The carrying value of cash and cash equivalents approximates fair value.

Restricted Deposits Restricted deposits consist of escrow funds associated with acquisitions as described in Note 2 of the Notes to Consolidated Financial Statements.

Accrued Insurance Expense Costs estimated to be incurred in the future for employee health and welfare benefits, workers compensation, property and casualty insurance programs resulting from claims which have been incurred are accrued currently. Under the terms of the Company s agreement with the various insurance carriers administering these claims, the Company is not required to remit the total premium until the claims are actually paid by the insurance companies.

Fair Value of Financial Instruments The carrying amounts of financial instruments, including cash and cash equivalents, customer receivables and accounts payable approximate fair value at January 31, 2010 and 2009, because of the relatively short maturity of those instruments. See Note 12 for disclosure regarding the fair value of indebtedness of the Company and Note 13 for disclosure regarding the fair value of derivative instruments.

Litigation and Other Contingencies The Company is involved in litigation incidental to its business, the disposition of which is not expected to have a material effect on the Company s business, financial position, results of operations or cash flows. It is possible, however, that future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company s assumptions related to these proceedings. The Company accrues its best estimate of the probable cost for the resolution of legal claims. Such estimates are developed in consultation with counsel handling these matters and are based upon a combination of litigation and settlement strategies. To the extent additional information arises or the Company s strategies change, it is possible that the Company s estimate of its probable liability in these matters may change.

Derivatives The Company follows guidance within ASC Topic 815, Derivatives and Hedging (ACS Topic 815), which requires derivative financial instruments to be recorded on the balance sheet at fair value and establishes criteria for designation and effectiveness of hedging relationships. The Company accounts for its hedges of certain forecasted foreign currency costs as cash flow hedges, such that changes in fair value for the effective portion of hedge contracts are recorded in accumulated other comprehensive income (loss) in stockholders equity, until the hedged item is recognized in operations. The ineffective portion of the derivatives change in fair value, if any, is immediately recognized in operations. In addition, the Company has entered into fixed-price natural gas contracts to manage fluctuations in the price of natural gas. These contracts result in the Company physically delivering gas, and as a result, are exempt from the requirements of ASC Topic 815 under the normal purchases and sales exception. Accordingly, the contracts are not reflected in the balance sheet at fair value and revenues from the contracts are recognized as the natural gas is delivered under the terms of the contracts (see Note 13 for disclosure regarding the fair value of derivative instruments). The Company does not enter into derivative financial instruments for speculative or trading purposes.

Supplemental Cash Flow Information The amounts paid for income taxes and interest are as follows:

(in thousands)	2010	2009	2008
Income taxes	$13,000	$18,843	$20,704
Interest	2,813	3,054	8,721

The Company had earnings on restricted deposits of $2,000, $30,000 and $287,000 for 2010, 2009 and 2008, respectively, which were treated as a non-cash item as they were restricted for the account of the escrow beneficiaries. Also, in fiscal 2010, the Company received land and buildings valued at $2,828,000 in a non-cash settlement of a legal dispute in Australia, and made a non-cash distribution of $280,000 of common stock for a prior year acquisition. See Note 6 for discussion of legal settlements and Note 2 for a discussion of acquisition activity.

During fiscal year 2009, the Company entered into financing obligations for software licenses amounting to $1,298,000, payable over three years. The associated assets are recorded as Other Intangible Assets in the balance sheet.

In connection with the Reynolds acquisition (see Note 2), during the year ended January 31, 2008, the Company settled the Earnout Amount on a discounted basis for $13,252,000, consisting of $2,270,000 in cash and 249,023 shares of common stock (valued at $10,982,000).

Income Taxes Income taxes are provided using the asset/ liability method, in which deferred taxes are recognized for the tax consequences of temporary differences between the financial statement carrying amounts and tax bases of existing assets and liabilities. Deferred tax assets are reviewed for recoverability and valuation allowances are provided as necessary. Provision for U.S. income taxes on undistributed earnings of foreign subsidiaries and affiliates is made only on those amounts in excess of those funds considered to be invested indefinitely (see Note 9).

Earnings Per Share Earnings per common share are based upon the weighted average number of common and dilutive equivalent shares outstanding. Options to purchase common stock are included based on the treasury stock method for dilutive earnings per share except when their effect is antidilutive. Options to purchase 453,630, 176,149 and 3,000 shares have been excluded from weighted average shares in 2010, 2009 and 2008, respectively, as their effect was antidilutive. A total of 67,975 and 73,587 nonvested shares have been excluded from weighted average shares in 2010 and 2009, respectively, as their effect was antidilutive.

Share-Based Compensation The Company follows the guidance codified within ASC Topic 718, Compensation-Stock Compensation (ASC Topic 718), under the modified prospective method and recognizes the cost of all share-based instruments in the financial statements using a fair-value measurement of compensation expense related to all share-based instruments over the term expected to be benefited by the instrument. As of January 31, 2010, the Company had unrecognized compensation expense of $3,347,000 to be recognized over a weighted average period of 1.55 years. The Company determines the fair value of share-based compensation using the Black-Scholes model.

Unearned compensation expense associated with the issuance of nonvested shares is amortized on a straight-line basis as the restrictions on the stock expire.

Other Comprehensive Loss Accumulated balances, net of income taxes, of Other Comprehensive Loss are as follows:

(in thousands)	Cumulative Translation Adjustment	Unrecognized Pension Liability	Unrealized Loss On Exchange Contracts	Accumulated Other Comprehensive Loss
Balance, January 31, 2008	$(6,391)	$ (596)	$	$ (6,987)
Period change, net of income tax	(2,549)	(421)	(96)	(3,066)
Balance, January 31, 2009	(8,940)	(1,017)	(96)	(10,053)
Period change, net of income tax	2,936	1,017	34	3,987
Balance, January 31, 2010	$(6,004)	$	$(62)	$ (6,066)

(2) Acquisitions

Fiscal Year 2010

The Company completed three acquisitions during fiscal 2010 as described below:

On December 9, 2009, the Company acquired certain assets of MCL Technology Corporation (MCL), an Arizona-based provider of commercial and industrial reverse osmosis, deionization and filtration services.

On October 30, 2009, the Company acquired 100% of the stock of W.L. Hailey & Company, Inc. (Hailey), a water and wastewater solutions firm in Tennessee. The operation was combined with similar service lines and serves to foster the Company s further expansion of these product lines into the southeast.

On May 1, 2009, the Company acquired equipment and other assets of Meadow Equipment Sales & Service, Inc. (Meadow), a construction company operating primarily in the Midwestern United States.

The aggregate cash purchase price of $16,961,000, comprised of cash ($3,150,000 of which was placed in escrow to secure certain representations, warranties and idemnifications), was as follows:

(in thousands)	MCL	Hailey	Meadow	Total
Cash purchase price	$1,500	$14,861	$600	$16,961
Escrow deposits	150	3,000		3,150

The purchase price for each acquisition has been allocated based on the fair value of the assets and liabilities acquired, determined based on the Company s internal operational assessments and other analyses. In accordance with new accounting guidance, beginning in fiscal 2010 acquisition related costs were recorded as an expense in the periods in which the costs were incurred. Based on the Company s allocations of the purchase price, the acquisitions had the following effect on the Company s consolidated financial position as of their respective closing dates:

(in thousands)	MCL	Hailey	Meadow	Total
Working capital	$ 80	$ 4,861	$	$ 4,941
Property and equipment	983	9,515	575	11,073
Goodwill	273	585		858
Other intangible assets	164		25	189
Deferred taxes		(100)		(100)
Total purchase price	$1,500	$14,861	$ 600	$16,961

The identifiable intangible assets associated with Meadow consist of non-compete agreements valued at $25,000 and have a weighted-average life of three years. The identifiable intangible assets associated with MCL consist of design efficiencies that provide a margin advantage over competitors valued at $164,000 and have a weighted-average life of five years. The $858,000 of aggregate goodwill was assigned to the water infrastructure segment and is expected to be deductible for tax purposes.

The results of operations of the acquired entities have been included in the Company s consolidated statements of income commencing with the respective closing dates. Hailey contributed revenues and income before income taxes to the Company for the period from October 30, 2009 through January 31, 2010, of $11,581,000 and $149,000, respectively. Revenue and income before income taxes for Meadow and MCL, since their respective closing dates, were not significant.

Pro forma amounts related to Meadow and MCL for prior periods have not been presented since the acquisitions would not have had a significant effect on the Company s consolidated revenues or net income. Assuming Hailey had been acquired as of the beginning of each period, the unaudited pro forma consolidated revenues, net income and net income per share would be as follows:

(in thousands, except per share data)	2010	2009
Revenues	$920,792	$1,078,314
Net income	3,454	28,009
Basic earnings per share	$ 0.18	$ 1.46
Diluted earnings per share	$ 0.18	$ 1.44

The pro forma information provided above is not necessarily indicative of the results of operations that would actually have resulted if the acquisition was made as of those dates or of results that may occur in the future.

On June 16, 2006 the Company acquired 100% of the outstanding stock of Collector Wells International, Inc. (CWI), a privately held specialty water services company that designs and constructs water supply systems. Under the terms of the purchase, there was contingent consideration up to a maximum of $1,400,000 (the Earnout Amount), which was based on a percentage of the amount by which CWI s earnings before interest, taxes, depreciation and amortization exceeded a threshold amount during the 36 months following the acquisition. During June 2009, the Company determined that the maximum consideration was achieved and settled the Earnout Amount, consisting of $1,120,000 in cash and $280,000 of Layne common stock, valued based on the average closing price of the five trading days ending June 9, 2009. The Company paid the cash portion of the settlement on July 10, 2009 and issued 12,677 shares of Layne common stock in payment of the stock portion. The Earnout Amount has been accounted for as additional purchase consideration and accordingly, in July 2009, the Company recorded $1,400,000 of additional goodwill, which is not expected to be deductible for tax purposes.

On November 30, 2007, the Company acquired certain assets and liabilities of SolmeteX Inc. (SolmeteX), a water and wastewater research and development business and supplier of wastewater filtration products to the dental market.

In addition to the initial purchase price, there is contingent consideration up to a maximum of $1,000,000 (the SolmeteX Earnout Amount), which is based on a percentage of the amount of SolmeteX s revenues during the 36 months following the acquisition. Any portion of the SolmeteX Earnout Amount that is ultimately paid will be accounted for as additional purchase consideration. Through January 31, 2010, the contingent earnout consideration earned by SolmeteX was $262,000, of which $33,000 was paid in March 2008 and $229,000 was paid in April 2009.

Fiscal Year 2009

The Company completed three acquisitions during the fiscal 2009 year as described below:

On October 24, 2008, the Company acquired 100% of the stock of Meadors Construction Co., Inc. (Meadors), a construction company operating primarily in Florida. The operation was combined with similar service lines and serves to foster our further expansion into Florida and the southeast.

On August 7, 2008, the Company acquired certain assets and liabilities of Moore & Tabor, a geotechnical construction firm operating in California.

On May 5, 2008, the Company acquired certain assets and liabilities of Wittman Hydro Planning Associates (WHPA), a water consulting firm specializing in hydrologic systems modeling and analysis.

The aggregate purchase price of $8,925,000, comprised of cash of $8,815,000 ($1,150,000 of which was placed in escrow to secure certain representations, warranties and idemnifications under the purchase agreements) and expenses of $110,000, was as follows:

(in thousands)	Meadors	Moore & Tabor	WHPA	Total
Cash	$4,536	$ 1,785	$2,494	$8,815
Expenses	53	33	24	110
Total purchase price	$4,589	$ 1,818	$2,518	$8,925
Escrow deposits	$ 700	$ 150	$ 300	$1,150

The purchase price for each acquisition has been allocated based on the fair value of the assets and liabilities acquired, determined based on the company s internal operational assessments and other analyses.

Based on the Company s allocations of the purchase price, the acquisitions had the following effect on the Company s consolidated financial position as of their respective closing dates:

(in thousands)	Meadors	Moore & Tabor	WHPA	Total
Working capital	$ 2,072	$ 427	$ 394	$ 2,893
Property and equipment	592	798	40	1,430
Goodwill	1,865	593	1,832	4,290
Other intangible assets	60		250	310
Other assets			2	2
Total purchase price	$ 4,589	$ 1,818	$ 2,518	$ 8,925

The identifiable intangible assets associated with Meadors consist of non-compete agreements valued at $60,000 and have a weighted-average life of two years. The identifiable intangible assets associated with WHPA consist of patents valued at $250,000, and have a weighted-average life of 15 years. The $4,290,000 of aggregate goodwill was assigned to the water infrastructure segment and is expected to be deductible for tax purposes.

The results of operations of the acquired entities have been included in the Company s consolidated statements of income commencing with the respective closing dates. Pro forma amounts for prior periods have not been presented as the acquisitions would not have had a significant effect on the Company s consolidated revenues or net income.

In addition to the initial purchase price, there is contingent consideration up to a maximum of $2,500,000 (the WHPA Earnout Amount), which is based on a percentage of the amount by which WHPA s earnings before interest, taxes, depreciation and amortization exceed a threshold amount during the 36 months following the acquisition. If earned, up to 80% of the WHPA Earnout Amount may be paid with Layne common stock, at the Company s discretion. Any portion of the WHPA Earnout Amount which is ultimately paid will be accounted for as additional purchase consideration.

Fiscal Year 2008

The Company completed two acquisitions during fiscal 2008 as described below:

On December 31, 2007 (the Tierdael Closing Date), the Company acquired certain assets and liabilities of Tierdael Construction (Tierdael), a pipeline and utility construction contractor in Denver which was combined with similar service lines.

On November 30, 2007 (the SolmeteX Closing Date), the Company acquired certain assets and liabilities of SolmeteX, Inc., a water and wastewater research and development business and a supplier of wastewater filtration products to the dental market.

The aggregate purchase price of $20,696,000, comprised of cash of $20,146,000 ($1,665,000 of which was placed in escrow to secure certain representations, warranties and idemnifications under the purchase agreements), assumed liabilites of $226,000 and expenses of $324,000, as reflected below:

(in thousands)	Tierdael	SolmeteX	Total
Cash	$ 6,646	$ 13,500	$ 20,146
Assumed liabilities	226		226
Expenses	238	86	324
Total purchase price	$ 7,110	$ 13,586	$ 20,696
Escrow deposits	$ 665	$ 1,000	$ 1,665

The purchase price for each acquisition has been allocated based on the fair value of the assets and liabilities acquired, determined based on the Company s internal operational assessments and other analyses.

Based on the Company s allocations of the purchase price, the acquisitions had the following effect on the Company s consolidated financial position as of their respective closing dates:

(in thousands)	Tierdael	SolmeteX	Total
Working capital	$3,983	$ 64	$ 4,047
Property and equipment	3,127	115	3,242
Goodwill		7,270	7,270
Tradenames		2,962	2,962
Patents		2,543	2,543
Deferred income taxes		551	551
Other intangible assets		81	81
Total purchase price	$7,110	$13,586	$20,696

Of the $6,056,000 of identifiable intangible assets associated with SolmeteX, $21,000 was assigned to research and development assets that were written off in selling, general and administrative expenses at the date of acquisition. The remaining $6,035,000 of acquired intangible assets have a weighted-average useful life of approximately 15.4 years, comprised of tradenames (15-year weighted-average useful life), patents (15-year weighted-average useful life), and other assets (20-year average useful life). The $7,270,000 goodwill was assigned to the water infrastructure segment. Of that total amount, $7,053,000 is expected to be deductible for tax purposes.

The results of operations of Tierdael have been included in the Company s consolidated statements of income commencing with the Tierdael closing date. Assuming Tierdael had been acquired as of the beginning of fiscal 2008, the unaudited pro forma consolidated revenues, net income and net income per share would be as follows:

(in thousands, except per share data)	2008
Revenues	$890,755
Net income	38,052
Basic earnings per share	$ 2.28
Diluted earnings per share	$ 2.25

The results of operations of SolmeteX have been included in the Company s consolidated statements of income commencing with the SolmeteX Closing Date. Assuming SolmeteX had been acquired as of the beginning of fiscal 2008, the unaudited pro forma consolidated revenues, net income and net income per share would be as follows:

(in thousands, except per share data)	2008
Revenues	$872,427
Net income	36,307
Basic earnings per share	$ 2.18
Diluted earnings per share	$ 2.14

The pro forma information provided above is not necessarily indicative of the results of operations that would actually have resulted if the acquisitions were made as of those dates or of results that may occur in the future. Pro forma results include adjustments for interest expense on the cash purchase price and depreciation and amortization expense on the acquisition adjustments to property and equipment and other intangible assets.

On September 28, 2005, the Company acquired 100% of the outstanding stock of Reynolds, Inc. (Reynolds), a privately held company and a major supplier of products and services to the water and wastewater industries. Under the terms of the purchase, there was contingent consideration up to a maximum of $15,000,000 (the Earnout Amount), which was based on Reynolds operating performance over a period of 36 months. During July 2007, the Company determined that it was probable that the maximum consideration would be achieved and agreed to settle the Earnout Amount on a discounted basis for $13,252,000, consisting of $2,270,000 in cash and $10,982,000 of Layne common stock, valued based on the average closing price of the five trading days ending July 31, 2007. The Company paid the cash portion of the settlement on July 31, 2007, and issued 249,023 shares of Layne common stock in August 2007 in payment of the stock portion. The Earnout Amount has been accounted for as additional purchase consideration, and accordingly the Company recorded $13,252,000 of additional goodwill in July 2007.

(3) Investments in Affiliates

The Company s investments in affiliates are carried at the fair value of the investment considered at the date acquired, plus the Company s equity in undistributed earnings from that date. These affiliates, which generally are engaged in mineral exploration drilling and the manufacture and supply of drilling equipment, parts and supplies, are as follows at January 31, 2010:

	Percentage Owned
Christensen Chile, S.A. (Chile)	50.00%
Christensen Commercial, S.A. (Chile)	50.00
Geotec Boyles Bros., S.A. (Chile)	50.00
Boyles Bros. Diamantina, S.A. (Peru)	29.49
Christensen Commercial, S.A. (Peru)	35.38
Geotec, S.A. (Peru)	35.38
Boytec, S.A. (Panama)	50.00
Plantel Industrial S.A. (Chile)	50.00
Boytec Sondajes de Mexico, S.A. de C.V. (Mexico)	50.00
Geoductos Chile, S.A. (Chile)	50.00
Mining Drilling Fluids (Panama)	25.00
Diamantina Christensen Trading (Panama)	42.69
Boyles Bros. do Brasil Ltd. (Brazil)	40.00
Boytec, S.A. (Columbia)	50.00
Centro Internacional de Formacion S.A. (Chile)	50.00
Geoestrella S.A.	25.00

Financial information of the affiliates is reported with a one-month lag in the reporting period. Summarized financial information of the affiliates as of January 31, 2010, 2009 and 2008, and for the years then ended, was as follows:

(in thousands)	2010	2009	2008
Current assets	$ 96,509	$ 99,533	$ 78,165
Noncurrent assets	62,484	62,570	42,682
Current liabilities	49,044	59,844	48,496
Noncurrent liabilities	11,748	13,319	9,373

Revenues	227,642	301,268	202,649
Gross profit	41,701	58,933	36,234
Operating income	23,115	40,081	24,074
Net income	16,841	32,626	18,762

The Company had no significant transactions or balances with its affiliates that resulted in amounts being included in the Consolidated Financial Statements as of January 31, 2010, 2009 and 2008, and for the years then ended.

The Company s equity in undistributed earnings of the affiliates totaled $29,428,000, $26,328,000 and $15,190,000 as of January 31, 2010, 2009 and 2008, respectively

(4) Impairment of Oil and Gas Properties

As of the end of each reporting period, the Company is required to assess the carrying value of its oil and gas properties under guidelines from the SEC, as more fully described in Note 1 (the Ceiling Test). Gas prices per Mcf used in the determinations as of January 31, 2010, 2009 and 2008, were $3.24, $3.29 and $7.53, respectively. As a result of the Ceiling Test, we recorded impairments of our oil and gas properties of $21,642,000 in the second quarter of fiscal 2010 and $26,690,000 in the fourth quarter of fiscal 2009. The impairment in the second quarter of fiscal 2010 was based on a gas price of $2.89 per Mcf.

We also recorded an impairment of $2,014,000 in the third quarter of fiscal 2009 related to the Company s exploration project in Chile, begun in 2008. Following initial core testing and further evaluation of infrastructure requirements, it was determined that recovery of the Company s investment was not likely and the costs were written off.

(5) Goodwill and Other Intangible Assets
Goodwill and other intangible assets consisted of the following as of January 31:

	2010		2009	
(in thousands)	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Goodwill	$92,532	$	$90,029	$
Amortizable intangible assets:				
Tradenames	$18,962	$(3,086)	$18,962	$(2,275)
Customer-related	332	(332)	332	(332)
Patents	3,152	(755)	3,152	(569)
Non-competition agreements	464	(423)	439	(387)
Other	2,754	(1,419)	2,590	(910)
Total amortizable intangible assets	$25,664	$(6,015)	$25,475	$(4,473)

Amortizable intangible assets are being amortized over their estimated useful lives of two to 40 years with a weighted average amortization period of 26 years. Total amortization expense for other intangible assets was $1,542,000, $1,536,000 and $1,123,000 in 2010, 2009 and 2008, respectively. Amortization expense for the subsequent five fiscal years is estimated as follows:

(in thousands)	
2011	$1,561
2012	1,232
2013	1,072
2014	1,070
2015	1,070

Of the total goodwill as of January 31, 2010 and 2009, $20,618,000 and $19,451,000, respectively, is expected to be tax deductible.

The carrying amount of goodwill attributed to each operating segment was as follows (in thousands):

	Energy	Water Infrastructure	Total
Balance, February 1, 2008	$950	$84,756	$85,706
Additions		4,323	4,323
Balance, January 31, 2009	950	89,079	90,029
Additions		2,503	2,503
Balance, January 31, 2010	$950	$91,582	$92,532

(6) Litigation Settlement Gains
In fiscal 2000, the Company initiated litigation against a former owner of a subsidiary and associated partners. The action stemmed from alleged competition in violation of non-competition agreements, and sought damages for lost profits and recovery of legal expenses. During the first quarter of fiscal 2010, the Company entered into an agreement

whereby it received certain land and buildings in settlement of these claims. The settlement was valued at $2,828,000, based on management s estimate of the fair market value of the land and buildings received considering current market conditions and information provided by a third party appraisal.

In fiscal 2008, the Company initiated litigation against former officers of a subsidiary and associated energy production companies. During September 2008, the Company entered into a settlement agreement whereby it received certain payments over a period through September 2009. Payments of $667,000 and $2,173,000 were received during the years ended January 31, 2010 and 2009, respectively, net of contingent attorney fees.

(7) Other Income

Other income consisted of the following for the years ended January 31:

(in thousands)	2010	2009	2008
Gain from disposal of property and equipment	$ 147	$ 30	$ 671
Interest income	458	1,065	953
Exchange gain (loss)	(802)	91	(430)
Miscellaneous, net	396	(145)	35
Total	$ 199	$1,041	$1,229

(8) Costs and Estimated Earnings on Uncompleted Contracts

(in thousands)	2010	2009
Costs incurred on uncompleted contracts	$1,008,409	$811,011
Estimated earnings	207,005	175,308
	1,215,414	986,319
Less: Billings to date	1,169,346	956,937
Total	$ 46,068	$ 29,382
Included in accompanying balance sheets under the following captions:		
Costs and estimated earnings in excess of billings on uncompleted contracts	$ 83,712	$ 63,638
Billings in excess of costs and estimated earnings on uncompleted contracts	(37,644)	(34,256)
Total	$ 46,068	$ 29,382

The Company bills its customers based on specific contract terms. Substantially all billed amounts are collectible within one year. As of January 31, 2010 and 2009, the Company held unbilled contract retainage amounts of $40,601,000 and $39,149,000, respectively.

(9) Income Taxes

Income before income taxes consists of the following:

(in thousands)	2010	2009	2008
Domestic	$1,651	$25,962	$46,649
Foreign	4,807	21,476	20,640
Total	$6,458	$47,438	$67,289

Components of income tax expense are as follows:

(in thousands)	2010	2009	2008
Currently due:			
U.S. federal	$ 10,226	$ 7,696	$17,226
State and local	3,044	1,820	3,125
Foreign	5,895	8,433	7,099
	19,165	17,949	27,450
Deferred:			
U.S. federal	(11,933)	1,355	1,632
State and local	(2,459)	1,085	288
Foreign	320	877	808
	(14,072)	3,317	2,728
Total	$ 5,093	$21,266	$30,178

Deferred income taxes result from temporary differences between the financial statement and tax bases of the Company s assets and liabilities. The sources of these differences and their cumulative tax effects are as follows

(in thousands)		2010			2009	
	Assets	Liabilities	Total	Assets	Liabilities	Total
Contract income	$ 1,371	$	$ 1,371	$ 659	$	$ 659
Inventories	2,177	(228)	1,949	1,912	(339)	1,573
Accrued insurance	4,770		4,770	4,395		4,395
Other accrued liabilities	1,884		1,884	1,720		1,720
Prepaid expenses		(674)	(674)		(718)	(718)
Bad debts	2,895		2,895	3,028		3,028
Employee compensation	5,619		5,619	5,010		5,010
Other	771	(261)	510	916	(22)	894

Total current	19,487	(1,163)	18,324	17,640	(1,079)	16,561
Cumulative translation adjustment	4,184		4,184	5,508		5,508
Buildings, machinery and equipment	754	(20,262)	(19,508)	336	(19,035)	(18,699)
Gas transportation facilities and equipment		(7,765)	(7,765)		(6,471)	(6,471)
Mineral interests and oil and gas properties	1,464		1,464		(9,024)	(9,024)
Intangible assets	659	(5,237)	(4,578)	731	(5,478)	(4,747)
Tax deductible goodwill	358		358	1,069		1,069
Accrued insurance	2,794		2,794	4,051		4,051
Retirement benefits	1,131		1,131	936	(337)	599
Share-based compensation	3,873		3,873	2,169		2,169
Unremitted foreign earnings		(2,169)	(2,169)		(4,878)	(4,878)
Other	2,947	(492)	2,455	1,547	(187)	1,360
Total noncurrent	18,164	(35,925)	(17,761)	16,347	(45,410)	(29,063)
Total	$37,651	$(37,088)	$ 563	$33,987	$(46,489)	$(12,502)

The Company has several Australian and African subsidiaries which have generated tax losses. The majority of these losses have been utilized to reduce the Company s federal and state income tax liabilities.

As of January 31, 2010, undistributed earnings of foreign subsidiaries and certain foreign affiliates included $45,500,000 for which no federal income or foreign withholding taxes have been provided. These earnings, which are considered to be invested indefinitely, become subject to income tax if they were remitted as dividends or if the Company were to sell its stock in the affiliates or subsidiaries. It is not practicable to determine the amount of income or withholding tax that would be payable upon remittance of these earnings.

Deferred income taxes were provided on undistributed earnings of certain foreign subsidiaries and foreign affiliates where the earnings are not considered to be invested indefinitely.

A reconciliation of the total income tax expense to the statutory federal rate is as follows:

(in thousands)	2010 Amount	2010 Effective Rate	2009 Amount	2009 Effective Rate	2008 Amount	2008 Effective Rate
Income tax at statutory rate	$ 2,260	35.0%	$16,603	35.0%	$23,551	35.0%
State income tax, net	380	5.9	1,888	4.0	2,219	3.3
Difference in tax expense resulting from:						
Nondeductible expenses	793	12.3	972	2.0	1,041	1.5
Taxes on foreign affiliates	(1,565)	(24.2)	(2,873)	(6.1)	(1,370)	(2.0)
Taxes on foreign operations	4,642	71.9	4,357	9.2	5,033	7.5
Cash surrender value of life insurance	(362)	(5.6)	673	1.4	(22)	
Qualified production activity deduction	(495)	(7.7)	(525)	(1.1)	(595)	(0.9)
Other	(560)	(8.7)	171	0.4	321	0.4
Total	$ 5,093	78.9%	$21,266	44.8%	$30,178	44.8%

Effective February 1, 2007, the Company adopted amended guidance for uncertain tax positions, now codified within ASC Topic 740, Income Taxes. The amendments clarified the accounting for uncertainty in income taxes recognized in an entity s financial statements. ASC Topic 740 prescribes a more-likely-than-not threshold for financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return.

The Company s adoption of the amendments relating to uncertain tax positions resulted in a cumulative effect adjustment increasing retained earnings by $465,000 as of February 1, 2007. Prior to the adoption, the Company classified income tax uncertainties as current liabilities. Upon adoption, approximately $4,600,000 was reclassified to non-current liabilities because the resolution of those tax uncertainties was not expected within 12 months.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

(in thousands)	2010	2009	2008
Balance, beginning of year	$7,612	$ 6,642	$ 6,152
Additions based on tax positions related to current year	1,583	3,033	3,248
Additions for tax positions of prior years	790	353	772
Impact of changes in exchange rate	626	(582)	79
Settlements with tax authorities	(271)	27	(162)
Reductions for tax positions of prior years	(307)	(1,031)	(2,995)
Reductions due to the lapse of statutes of limitation	(721)	(830)	(452)
Balance, end of year	$9,312	$ 7,612	$ 6,642

Substantially all of the unrecognized tax benefits recorded would affect the effective rate if recognized. It is expected that the amount of unrecognized tax benefits will change during the next year; however, the Company does not expect the change to have a significant impact on its results of operations or financial position.

The Company classifies interest and penalties related to income taxes as a component of income tax expense, which is consistent with the recognition of these items in prior years. As of January 31, 2010, 2009 and 2008, the Company had $3,686,000, $2,872,000 and $2,752,000, respectively, of interest and penalties accrued associated with unrecognized tax benefits. The liability for interest and penalties increased $814,000, $120,000 and $970,000 during the years ended January 31, 2010, 2009 and 2008, respectively.

The Company files income tax returns in the U.S. federal jurisdiction, various state jurisdictions and certain foreign jurisdictions. The statute of limitations expired for the tax year ended January 31, 2006, during the year ended January 31, 2010. The Company is currently under IRS examination for tax year ended January 31, 2008. The tax years ended January 31, 2007, 2009 and 2010 remain open to examination. The Company has several state examinations currently in progress.

The Company files tax returns in the foreign jurisdictions where it operates. The returns are subject to examination and income tax examinations may be ongoing at any point in time. Tax liabilities are recorded based on estimates of additional taxes which will be due upon settlement of those examinations. The tax years subject to examination by foreign tax authorities vary by jurisdiction, but generally the tax years 2005 through 2010 remain open to examination.

(10) Operating Leases and Other Obligations

Future minimum rental payments required under operating leases that have initial or remaining noncancelable lease terms in excess of one year from January 31, 2010, are as follows:

(in thousands)

2011	$11,960
2012	7,770
2013	5,882
2014	3,771
2015	1,031
Thereafter	

Operating leases are primarily for light and medium duty trucks and other equipment. Rent expense under operating leases (including insignificant amounts of contingent rental payments) was $28,816,000, $31,660,000 and $27,977,000 in 2010, 2009 and 2008, respectively.

Asset retirement obligations consist of the estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. An asset retirement obligation and the related asset retirement cost are recorded when a well is drilled and completed. The asset retirement cost is determined based on the expected costs to complete the reclamation at the end of the well s economic life, discounted to its present value using a credit-adjusted risk-free rate. After initial recording, the liability is increased for the passage of time, with the increase being reflected in the consolidated statements of income as depreciation, depletion and amortization. Asset retirement costs are capitalized as part of oil and gas properties and depleted accordingly. Additions to the asset retirement obligations during the years ended January 31, 2010, 2009 and 2008 were $106,000, $185,000 and $170,000, respectively. Accretion during the same periods was $87,000, $77,000, and $60,000, respectively. The carrying values of the asset retirement obligations as of January 31, 2010 and 2009 were $1,498,000 and $1,305,000, respectively, and are recorded in Other Long Term Liabilities.

(11) Employee Benefit Plans

The Company sponsored a pension plan covering certain hourly employees not covered by union-sponsored, multi-employer plans. Benefits were computed based mainly on years of service. The Company made annual contributions to the plan substantially equal to the amounts required to maintain the qualified status of the plan. Contributions were intended to provide for benefits related to past and current service with the Company. Effective December 31, 2003, the Company froze the pension plan, ceased accrual of benefits and no further employees were added to the Plan.

On January 29, 2010, the Company terminated the plan and distributed $10,054,000 to an annuity provider and fulfilled the remaining obligations for approximately $300,000 in cash. These distributions triggered a settlement under guidance within ASC Topic 715 Compensation Retirement Benefits (ASC Topic 715), and resulted in a recognized settlement loss of $4,980,000 in fiscal 2010.

Beginning with the Company s fiscal year ended January 31, 2009, ASC Topic 715 Compensation Retirement Benefits (ASC Topic 715) requires a company to measure its plan assets and benefit obligations as of its fiscal balance sheet date. The Company had previously used December 31 as its measurement date. The Company elected to apply the transition option under which a 13-month measurement was determined as of December 31, 2007, that covers the period until the fiscal year-end measurement is required on January 31, 2009. As a result, the Company recorded a $47,000 decrease to retained earnings as of February 1, 2008.

The following table sets forth the plan s funded status as of the measurement dates and the amounts recognized in the Company s Consolidated Balance Sheets at January 31, 2010 and 2009:

(in thousands)	2010	2009
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 7,194	$7,326
Service cost		
Interest cost	475	513
Actuarial gain (loss)	3,175	(195)
Benefits paid	(490)	(450)
Plan settlement	(10,354)	
Benefit obligation at end of year		7,194
Change in plan assets:		
Fair value of plan assets at beginning of year	8,106	9,109
Actual return on plan assets	(61)	(553)
Employer contributions	2,799	
Benefits paid	(490)	(450)
Plan settlement	(10,354)	
Fair value of plan assets at end of year		8,106
Funded status recognized as other non-current assets	$	$ 912

Net periodic pension cost for 2010, 2009 and 2008 includes the following components:

(in thousands)	2010	2009	2008
Service cost and expenses	$ 86	$ 105	$ 96
Interest cost	475	513	450
Expected return on assets	(268)	(592)	(536)
Net amortization	104	149	215
Settlement loss	4,980		
Net periodic pension cost	$5,377	$ 175	$ 225

The Company has recognized the full amount of its actuarially determined pension liability.

The weighted average assumptions used to determine the benefit obligation and the net periodic pension cost for the years ending January 31, 2010, 2009 and 2008, are as follows:

	2010	2009	2008
Discount rate	6.92%	6.92%	6.49%
Expected long-term return on plan assets	3.5%	7.0%	7.0%
Rate of compensation increase	N/A	N/A	N/A
Health care cost trend on covered charges	N/A	N/A	N/A
Market-related value of assets	N/A	N/A	N/A
Expected return on assets	Smoothed value	Smoothed value	Smoothed value

The estimated long-term rate of return on assets was developed based on the historical returns and the future expectations for returns for each asset class, as well as the target asset allocation of the pension portfolio. Benefit level assumptions for 2010, 2009 and 2008 are based on fixed amounts per year of credited service.

The percentage of the fair value of total plan assets for each major category of plan assets as of the measurement date follows:

	As of January 31, 2009
Equity securities	%
Debt securities	13
Cash and cash equivalents	87
Total	100%

The Company s investment policy included the following asset allocation guidelines, which were effective for all periods presented:

	Normal Weighting	Policy Range
Equity securities	60%	40-70%
Debt securities	35	20-60
Cash and cash equivalents	5	0-15

As of January 31, 2009, in anticipation of the Company s decision to settle the obligations of the plan in 2010, the asset allocation was shifted out of equity securities into short-term bonds.

The asset allocation policy was developed in consideration of the following long-term investment objectives: to achieve long-term inflation-adjusted growth in asset values through investments in common stock and fixed income obligations, to minimize risk by maintaining an allocation to cash equivalents, to manage the portfolio to conform to ERISA requirements, to manage plan assets on a total return basis, and to maximize total returns consistent with an appropriate level of risk. Risk is to be controlled via diversification of investments among and within asset classes.

The Company contracted with a financial institution to provide investment management services. Full discretion in portfolio investments was given to the investment manager subject to the asset allocation guidelines and the following additional guidelines:

Equity Securities Allowable equity securities include common stocks listed on any U.S. stock exchange or over-the-counter common stocks, preferred and convertible securities. The equity holdings of any single issuer should aggregate to no more than 10% of the total market value of the plan.

International Securities Allowable international securities include common stocks, preferred stocks, warrants, convertible securities, as well as government and corporate debt securities.

Mutual Funds Mutual funds may be utilized for investments in fixed income, equity and international securities to enhance diversification and performance.

Fixed Income Securities Allowable fixed income securities include U.S. Treasury securities, U.S. Agency securities and corporate bonds. All fixed income securities shall be rated A or better at the time of purchase. No fixed income security shall continue to be held if its rating falls below BBB. The securities of any single issuer, with the exception of U.S. Treasuries and Agencies, should aggregate to no more than 10% of the total market value of the Plan. The fixed income segment of the portfolio will generally have an intermediate average maturity (five to 10 years) and a maximum permitted maturity for an individual issue of 15 years.

The Company s policy with respect to funding the qualified pension plan was to fund at least the minimum required by ERISA and not more than the maximum deductible for tax purposes. No contribution is required by ERISA for the January 1 to December 31, 2010, plan year, as the plan is settled.

The Company also provides supplemental retirement benefits to its chief executive officer. Benefits are computed based on the compensation earned during the highest five consecutive years of employment reduced for a portion of Social Security benefits and an annuity equivalent of the chief executive s defined contribution plan balance. The Company does not contribute to the plan or maintain any investment assets related to the expected benefit obligation. The Company has recognized the full amount of its actuarially determined pension liability. The amounts recognized in the Company s consolidated balance sheets at January 31, 2010 and 2009, were $2,899,000 and $2,432,000. Net periodic pension cost of the supplemental retirement benefits for 2010, 2009 and 2008 include the following components:

(in thousands)	2010	2009	2008
Service cost	$291	$269	$176
Interest cost	176	142	103
Net periodic pension cost	$467	$411	$279

The Company also participates in a number of defined benefit, multi-employer plans. These plans are union-sponsored, and the Company makes contributions equal to the amounts accrued for pension expense. Total union pension expense for these plans was $3,427,000, $3,780,000 and $2,961,000 in 2010, 2009 and 2008, respectively. Information regarding assets and accumulated benefits of these plans has not been made available to the Company.

The Company s salaried and certain hourly employees participate in Company-sponsored, defined contribution plans. Total expense for the Company s portion of these plans was $3,920,000, $4,215,000 and $3,777,000 in 2010, 2009 and 2008, respectively.

The Company has a deferred compensation plan for certain management employees. Participants may elect to defer up to 25% of their salaries and up to 50% of their bonuses to the plan. Company matching contributions, and the vesting period of those contributions, are established at the discretion of the Company. Employee deferrals are vested at all times. The total amount deferred, including Company matching, for 2010, 2009 and 2008 was $1,658,000, $1,939,000 and $2,237,000, respectively. The total liability for deferred compensation was $7,042,000 and $4,229,000 as of January 31, 2010 and 2009, respectively.

(12) Indebtedness

The Company maintains an agreement (Master Shelf Agreement) whereby it can issue up to $50,000,000 in additional unsecured notes before September 15, 2012. On July 31, 2003, the Company issued $40,000,000 of notes (Series A Senior Notes) under the Master Shelf Agreement. The Series A Senior Notes bear a fixed interest rate of 6.05% and are due on July 31, 2010, with annual principal payments of $13,333,000. The Company issued an additional $20,000,000 of notes under the Master Shelf Agreement in October 2004 (Series B Senior Notes). The Series B Senior Notes bear a fixed interest rate of 5.40% and are due on September 29, 2011, with annual principal payments of $6,667,000.

The Company also maintains a revolving credit facility under an Amended and Restated Loan Agreement (the Credit Agreement) with Bank of America, as Administrative Agent and as Lender (the Administrative Agent), and the other Lenders listed therein (the Lenders), which contains a revolving loan commitment of $200,000,000, less any outstanding letter of credit commitments (which are subject to a $30,000,000 sublimit). The Credit Agreement provides for interest at variable rates equal to, at the Company s option, a LIBOR rate plus 0.75% to 2.00%, or a base rate, as defined in the Credit Agreement plus up to 0.50%, depending upon the Company s leverage ratio. The Credit Agreement is unsecured and is due and payable November 15, 2011. On January 31, 2010, there were letters of credit of $19,805,000 and no borrowings outstanding on the Credit Agreement resulting in available capacity of $180,195,000.

The Master Shelf Agreement and the Credit Agreement contain certain covenants including restrictions on the incurrence of additional indebtedness and liens, investments, acquisitions, transfer or sale of assets, transactions with affiliates, payment of dividends and certain financial maintenance covenants, including among others, fixed charge coverage, maximum debt to EBITDA and minimum tangible net worth. The Company was in compliance with its covenants as of January 31, 2010.

Compliance with the financial covenants is required on a quarterly basis, using the most recent four fiscal quarters. The Company s fixed charge coverage ratio and leverage ratio covenants are based on ratios utilizing adjusted EBITDA and adjusted EBITDAR, as defined in the agreements. Adjusted EBITDA is generally defined as consolidated net income excluding net interest expense, provision for income taxes, gains or losses from extraordinary items, gains or losses from the sale of capital assets, non-cash items including depreciation and amortization, and share-based compensation. Equity in earnings of affiliates is included only to the extent of dividends or distributions received. Adjusted EBITDAR is defined as adjusted EBITDA, plus rent expense. The Company s tangible net worth covenant is based on stockholders equity less intangible assets. All of these measures are considered non-GAAP financial measures and are not intended to be in accordance with accounting principles generally accepted in the United States.

The Company s minimum fixed charge coverage ratio covenant is the ratio of adjusted EBITDAR to the sum of fixed charges. Fixed charges consist of rent expense, interest expense, and principal payments of long-term debt. The Company s leverage ratio covenant is the ratio of total funded indebtedness to adjusted EBITDA. Total funded indebtedness generally consists of outstanding debt, capital leases, unfunded pension liabilities, asset retirement obligations and escrow liabilities. The Company s tangible net worth covenant is measured based on stockholders equity, less intangible assets, as compared to a threshold amount defined in the agreements. The threshold is adjusted over time based on a percentage of net income and the proceeds from the issuance of equity securities.

As of January 31, 2010 and 2009, the Company s actual and required covenant levels were as follows:

(in thousands, except ratio data)	Actual 2010	Required 2010	Actual 2009	Required 2009
Minimum fixed charge coverage ratio	2.23	1.50	4.22	1.50
Maximum leverage ratio	0.42	3.00	0.44	3.00
Minimum tangible net worth	$346,215	$296,266	$340,280	$291,237

Maximum borrowings outstanding under the Company s credit agreements during 2010 and 2009 were $46,667,000 and $60,000,000, respectively, and the average outstanding borrowings were $36,100,000 and $52,200,000 , respectively. The weighted average interest rates, including amortization of loan costs, were 6.8% and 6.4%, respectively.

Loan costs incurred for securing long-term financing are amortized using a method that approximates the effective interest method over the term of the respective loan agreement. Amortization of these costs for 2010, 2009 and 2008 was $170,000, $183,000 and $169,000, respectively. Amortization of loan costs is included in interest expense in the consolidated statements of income.

Debt outstanding as of January 31, 2010 and 2009, whose carrying value approximates fair market value, was as follows:

(in thousands)	2010	2009
Long-term debt:		
Credit Agreement	$	$
Senior Notes	26,667	46,667
Total debt	26,667	46,667
Less current maturities	(20,000)	(20,000)
Total long-term debt	$ 6,667	$ 26,667

As of January 31, 2010, debt outstanding will mature by fiscal year as follows:

(in thousands)	
2011	$20,000
2012	6,667
Thereafter	

(13) Derivatives

The Company s energy division is exposed to fluctuations in the price of natural gas and has entered into fixed-price physical delivery contracts to manage natural gas price risk for a portion of its production. As of January 31, 2010, the Company had committed to deliver 885,000 million British Thermal Units (MMBtu) of natural gas through March 2010 at prices ranging from $7.68 to $10.67 per MMBtu.

The fixed-price physical delivery forward sales contracts will result in the physical delivery of natural gas, and as a result, are exempt from the requirements of ASC Topic 815 under the normal purchases and sales exception. Accordingly, the contracts are not reflected in the balance sheet at fair value and revenues from the contracts are recognized as the natural gas is delivered under the terms of the contracts. The estimated fair value of such contracts at January 31, 2010, was $2,831,000.

Additionally, the Company has foreign operations that have significant costs denominated in foreign currencies, and thus is exposed to risks associated with changes in foreign currency exchange rates. At any point in time, the Company might use various hedge instruments, primarily foreign currency option contracts, to manage the exposures associated with forecast expatriate labor costs and purchases of operating supplies. The Company does not enter into foreign currency derivative financial instruments for speculative or trading purposes.

As of January 31, 2010, the Company held option contracts with an aggregate U.S. dollar notional value of $7,600,000, which are intended to hedge exposure to Australian dollar fluctuations. The contracts settle in various increments through January 31, 2011. As of January 31, 2010 and 2009, respectively, the fair value of the outstanding derivatives was a loss of $102,000 and $158,000, recorded in other accrued expenses on the balance sheet, and net of income taxes of $40,000 and $62,000 in accumulated comprehensive income. The fair value of foreign currency contracts is estimated based on comparable quotes from brokers.

(14) Fair Value Measurements

In September 2006, the FASB issued guidance now codified within ASC Topic 820, Fair Value Measurements and Disclosures, which defines fair value, establishes a three-level fair value hierarchy based upon the assumptions (inputs) used to price assets or liabilities, and expands disclosures about fair value measurements. The hierarchy requires the Company to maximize the use of observable inputs and minimize the use of unobservable inputs. The three levels of inputs used to measure fair value are listed below:

Level 1 Unadjusted quoted prices in active markets for identical assets or liabilities.

Level 2 Observable inputs other than those included in Level 1, such as quoted market prices for similar assets and liabilities in active markets or quoted prices for identical assets in inactive markets.

Level 3 Unobservable inputs reflecting our own assumptions and best estimate of what inputs market participants would use in pricing an asset or liability.

The Company s assessment of the significance of a particular input to the fair value in its entirety requires judgment and considers factors specific to the asset or liability. The Company s financial instruments held at fair value, which include restricted deposits held in acquisition escrow accounts, and foreign currency option contracts, are presented below as of January 31, 2010 and January 31, 2009 (in thousands):

	Carrying	Fair Value Measurements		
	Value	Level 1	Level 2	Level 3
January 31, 2010				
Financial Assets:				
Restricted deposits held at fair value	$ 4,566	$ 4,566	$	$
Financial Liabilities:				
Foreign currency contracts	$ (102)	$	$ (102)	$
January 31, 2009				
Financial Assets:				
Restricted deposits held at fair value	$ 1,929	$ 1,929	$	$
Financial Liabilities:				
Foreign currency contracts	$ (158)	$	$ (158)	$

(15) Stock and Stock Option Plans

In October 2008, the Company amended the Rights Agreement signed in October 1998 whereby the Company authorized and declared a dividend of one preferred share purchase right (Right) for each outstanding common share of the Company. Subject to limited exceptions, the Rights are exercisable if a person or group acquires or announces a tender offer for 20% or more of the Company s common stock. Each Right will entitle shareholders to buy one one-hundredth of a share of a newly created Series A Junior Participating Preferred Stock of the Company at an exercise price of $75.00. The Company is entitled to redeem the Right at $.01 per Right at any time before a person has acquired 20% or more of the Company s outstanding common stock. The Rights expire three years from the date of grant.

In October 2007, the Company completed a public stock offering of 3,105,000 common shares. Proceeds of the offering, net of issuance costs of $9,344,000, were $159,879,000.

The Company has stock option and employee incentive plans that provide for the granting of options to purchase or the issuance of shares of common stock at a price fixed by the Board of Directors or a committee. As of January 31, 2010, there were an aggregate of 2,850,000 shares registered under the plans, 1,537,000 of which remain available to be granted under the plans. Of this amount, 250,000 shares may only be granted as stock in payment of bonuses and 1,287,000 may be issued as stock or options. The Company has the ability to issue shares under the plans either from new issuances or from treasury, although it has previously always issued new shares and expects to continue to issue new shares in the future. In the years ended January 31, 2010 and 2009, the Company purchased and subsequently cancelled 5,374 and 5,357, respectively, shares of stock related to settlement of withholding obligations.

The Company recognized $4,841,000, $4,084,000 and $3,026,000 of compensation cost for share-based plans for the years ended January 31, 2010, 2009 and 2008, respectively. Of these amounts, $603,000, $1,369,000 and $638,000, respectively, related to nonvested stock. It was determined in fiscal 2010 that 33,825 of nonvested shares issued in fiscal 2009 were unlikely to vest as they are contingent upon meeting performance requirements in fiscal 2011 that are not likely to be met. Accordingly, the Company reversed $805,000 in compensation cost in fiscal 2010 related to these shares. The total income tax benefit recognized for share-based compensation arrangements was $1,888,000, $1,578,000 and $1,170,000 for the years ended January 31, 2010, 2009 and 2008, respectively.

A summary of nonvested share activity for 2010, 2009 and 2008 is as follows:

	Number of Shares	Weighted Average Grant Date Fair Value	Aggregate Intrinsic Value (in thousands)
Nonvested stock at January 31, 2007	1,000	$29.70	
Granted	73,863	42.76	
Vested	(1,000)	29.70	
Nonvested stock at January 31, 2008	73,863	$42.76	
Granted	38,584	37.39	
Vested	(22,638)	42.76	
Nonvested stock at January 31, 2009	89,809	$40.48	
Granted	12,771	17.79	
Vested	(23,244)	42.51	
Nonvested stock at January 31, 2010	79,336	$36.23	$2,010

Significant option groups outstanding at January 31, 2010, and related exercise price and remaining contractual term follows:

Grant Date	Options Outstanding	Options Exercisable	Exercise Price	Remaining Contractual Term (Months)
4/00	13,794	13,794	3.495	3
6/04	20,000	20,000	16.600	53
6/04	71,526	71,526	16.650	53
6/05	10,000	10,000	17.540	65
9/05	140,332	140,332	23.050	68
1/06	191,481	191,481	27.870	72
6/06	10,000	10,000	29.290	77
6/06	70,000	52,500	29.290	77
6/07	65,625	30,625	42.260	89
7/07	33,000	16,500	42.760	90

9/07	3,000	1,500	55.480	92
2/08	74,524	24,835	35.710	96
1/09	6,000	6,000	24.010	107
2/09	201,311		15.780	108
2/09	4,580	4,580	15.780	108
6/09	108,582		21.990	112
6/09	2,472	2,472	21.990	112
	1,026,227	596,145		

All options were granted at an exercise price equal to the fair market value of the Company s common stock at the date of grant. The options have terms of 10 years from the date of grant and generally vest ratably over periods of one month to five years. Certain option awards provide for accelerated vesting if there is a change of control (as defined in the plans) and for equitable adjustments in the event of changes in the Company s equity structure. The Company does not expect any nonvested options to be forfeited. The fair value of options at date of grant was estimated using the Black-Scholes model. The weighted average fair value at the date of grant for options granted during 2010, 2009 and 2008 was $9.92, $16.30 and $20.82, respectively. The fair value was based on an expected life of six years, no dividend yield, an average risk-free rate of 2.14%, 2.48% and 4.79%, respectively, and assumed volatility of 62%, 48% and 38%, respectively.

Stock option transactions for 2010, 2009 and 2008 were as follows:

	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (years)	Aggregate Intrinsic Value (in thousands)
Stock Option Activity Summary:				
Outstanding at January 31, 2007	963,529	$20.028		
Exercisable at January 31, 2007	413,356	$15.202		
Granted	106,000	42.790		
Exercised	(215,106)	13.632		$6,890
Canceled				
Forfeited	(3,750)	16.650		151
Expired	(723)	11.400		19
Outstanding at January 31, 2008	849,950	$24.541		
Exercisable at January 31, 2008	392,585	$19.944		
Granted	80,524	34.838		
Exercised	(189,033)	17.578		6,385
Canceled				
Forfeited				

Expired				
Outstanding at January 31, 2009	741,441	$27.435		
Exercisable at January 31, 2009	437,358	$23.659		
Granted	316,945	17.956		
Exercised	(32,159)	16.293		384
Canceled				
Forfeited				
Expired				
Outstanding at January 31, 2010	1,026,227	$24.856	7.02	$3,840
Exercisable at January 31, 2010	596,145	$25.814	5.82	$1,554

(16) Contingencies

The Company s drilling activities involve certain operating hazards that can result in personal injury or loss of life, damage and destruction of property and equipment, damage to the surrounding areas, release of hazardous substances or wastes and other damage to the environment, interruption or suspension of drill site operations and loss of revenues and future business. The magnitude of these operating risks is amplified when the Company, as is frequently the case, conducts a project on a fixed-price, bundled basis where the Company delegates certain functions to subcontractors but remains responsible to the customer for the subcontracted work. In addition, the Company is exposed to potential liability under foreign, federal, state and local laws and regulations, contractual indemnification agreements or otherwise in connection with its services and products. Litigation arising from any such occurrences may result in the Company being named as a defendant in lawsuits asserting large claims. Although the Company maintains insurance protection that it considers economically prudent, there can be no assurance that any such insurance will be sufficient or effective under all circumstances or against all claims or hazards to which the Company may be subject or that the Company will be able to continue to obtain such insurance protection. A successful claim or damage resulting from a hazard for which the Company is not fully insured could have a material adverse effect on the Company. In addition, the Company does not maintain political risk insurance with respect to its foreign operations.

The Company is involved in various other matters of litigation, claims and disputes which have arisen in the ordinary course of the Company s business. The Company believes that the ultimate disposition of these matters will not, individually and in the aggregate, have a material adverse effect upon its business or consolidated financial position, results of operations or cash flows.

On April 30, 2008, Levelland/Hockley County Ethanol, LLC (Levelland) filed a Complaint against the Company in the District Court for Hockley County, Texas. On May 28, 2008, the Company removed the case to the United States District Court for the Northern District of Texas, Lubbock Division. On June 2, 2008, Levelland filed a First Amended Complaint against the Company in the Federal District Court for the Northern District of Texas, Lubbock Division. Levelland owns an ethanol plant located in Levelland, Texas. In July 2007, Levelland entered into a lease agreement with the Company for certain water treatment equipment for the ethanol plant. Levelland alleges that the equipment leased from the Company fails to treat the water coming into the ethanol plant to required levels. The First Amended Complaint seeks damages for breach of contract, breach of warranty, violation of the Texas Deceptive Trade Practices Act, negligence, negligent misrepresentation and fraud, in connection with the design and construction of the water treatment facility. The Company and Levelland reached agreement on a settlement of the matter in fiscal 2010. No additional expense was necessary as a result of the settlement.

(17) Segments and Foreign Operations

The Company is a multinational company that provides sophisticated services and related products to a variety of markets, as well as being a producer of unconventional natural gas for the energy market. Management defines the Company s operational organizational structure into discrete divisions based on its primary product lines. Each division comprises a combination of individual district offices, which primarily offer similar types of services and serve similar types of markets. Although individual offices within a division may periodically perform services normally provided by another division, the results of those services are recorded in the offices own division. For example, if a mineral exploration division office performed water well drilling services, the revenues would be recorded in the mineral exploration division rather than the water infrastructure division. The Company s segments are defined as follows:

Water Infrastructure

This division provides a full line of water-related services and products including soil stabilization, hydrological studies, site selection, well design, drilling and development, pump installation, and well rehabilitation. The division s offerings include the design and construction of water and wastewater treatment facilities, the provision of filter media and membranes to treat volatile organics and other contaminants such as nitrates, iron, manganese, arsenic, radium and radon in groundwater, Ranney collector wells, sewer rehabilitation and water and wastewater transmission lines. The division also offers environmental services to assess and monitor groundwater contaminants.

Mineral Exploration Division

This division provides a complete range of drilling services for the mineral exploration industry. Its aboveground and underground drilling activities include all phases of core drilling, diamond, reverse circulation, dual tube, hammer and rotary air-blast methods.

Energy Division

This division focuses on the exploration and production of oil and gas properties, primarily concentrating on projects in the mid-continent region of the United States.

Other

Other includes two small specialty energy service companies and any other specialty operations not included in one of the other divisions.

Financial information for the Company s segments is presented below. Unallocated corporate expenses primarily consist of general and administrative functions performed on a company-wide basis and benefiting all segments. These costs include accounting, financial reporting, internal audit, safety, treasury, corporate and securities law, tax compliance, certain executive management (chief executive officer, chief financial officer and general counsel) and board of directors. Corporate assets are all assets of the Company not directly associated with a segment, and consist primarily of cash and deferred income taxes.

(in thousands) As of and for the Year Ended January 31,	2010	2009	2008
Revenues			
Water infrastructure	$698,506	$ 766,957	$639,584
Mineral exploration	118,188	188,918	178,482
Energy	45,940	46,352	39,749
Other	3,783	5,836	10,459
Total revenues	$866,417	$1,008,063	$868,274
Equity in earnings of affiliates			
Mineral exploration	$ 8,198	$ 14,089	$ 8,076
Income (loss) before income taxes			
Water infrastructure	$ 33,017	$ 48,399	$ 42,995
Mineral exploration	11,149	39,260	37,452
Energy	(6,393)	(12,401)	13,075
Other	308	1,280	3,696
Unallocated corporate expenses	(28,889)	(25,486)	(21,199)
Interest	(2,734)	(3,614)	(8,730)
Total income before income taxes	$ 6,458	$ 47,438	$ 67,289
Investment in affiliates			
Mineral exploration	$ 44,073	$ 40,973	$ 29,835
Total assets			
Water infrastructure	$438,481	$ 422,383	$388,491
Mineral exploration	130,332	125,588	110,064
Energy	64,822	100,309	112,363
Other	2,043	2,482	2,449
Corporate	95,277	68,595	83,588
Total assets	$730,955	$ 719,357	$696,955
Capital expenditures			
Water infrastructure	$ 27,162	$ 27,924	$ 22,029
Mineral exploration	10,433	20,944	18,451
Energy	4,551	30,891	30,345
Other	134	237	1,037

Corporate	2,545	1,027	1,508
Total capital expenditures	$ 44,825	$ 81,023	$ 73,370
Depreciation, depletion and amortization			
Water infrastructure	$ 25,303	$ 23,741	$ 21,978
Mineral exploration	13,602	13,362	10,523
Energy	17,176	14,644	10,704
Other	311	935	237
Corporate	1,287	158	178
Total depreciation, depletion and amortization	$ 57,679	$ 52,840	$ 43,620

(in thousands) Fiscal Years Ended January 31,	2010	2009	2008
Geographic information:			
Revenues			
United States	$762,442	$ 841,542	$712,098
Australia/Africa	49,173	88,967	89,739
Mexico	25,236	37,775	42,242
Other foreign	29,566	39,779	24,195
Total revenues	$866,417	$1,008,063	$868,274
Property and equipment, net			
United States	$194,911	$ 213,408	$218,047
Australia/Africa	22,319	18,663	19,530
Mexico	7,004	9,379	8,555
Other foreign	8,538	5,295	1,235
Total property and equipment, net	$232,772	$ 246,745	$247,367

(18) New Accounting Pronouncements

In June 2009, the Financial Accounting Standards Board (FASB) issued guidance now codified within FASB Accounting Standards Codification (ASC) Topic 105, Generally Accepted Accounted Principles, establishing the ASC as the single source of authoritative nongovernmental U.S. generally accepted accounting principles (GAAP), superseding existing FASB, American Institute of Certified Public Accountants, Emerging Issues Task Force, and related accounting literature. The ASC reorganizes the thousands of GAAP pronouncements into roughly 90 accounting topics and displays them using a consistent structure. Also included is relevant Securities and Exchange Commission guidance organized using the same topical structure in separate sections. This guidance was effective for financial statements issued for reporting periods that ended after September 15, 2009. The adoption did not impact the Company s financial position, results of operations or liquidity.

In January 2010, the FASB issued guidance amending ASC Topic 820 to require new disclosures concerning transfers into and out of Levels 1 and 2 of the fair value measurement hierarchy, and activity in Level 3 measurements. In addition, the guidance clarifies certain existing disclosure requirements regarding the level of disaggregation and inputs and valuation techniques and makes conforming amendments to the guidance on employers disclosures about postretirement benefit plans assets. This guidance is effective for interim and annual reporting periods beginning after December 15, 2009; however, the requirements to disclose separately purchases, sales, issuances, and settlements in the Level 3 reconciliation are effective for fiscal years beginning after December 15, 2010 (and for interim periods within such years). The Company does not expect the adoption to have a material impact on its financial position, results of operations or cash flows.

In June 2009, the FASB issued guidance which has not yet been codified in the ASC, amending the consolidation guidance applicable to variable interest entities. The amendments will affect the overall consolidation analysis under ASC Topic 810, Consolidation. This guidance will be effective as of the beginning of the Company s fiscal year ending January 31, 2011. The Company does not expect the adoption to have a material impact on its financial position, results of operations or cash flows.

In December 2007, the FASB issued guidance now codified within ASC Topic 810, Consolidation. This guidance requires us to classify noncontrolling interests (previously referred to as minority interest) as part of consolidated net earnings and to include the accumulated amount of noncontrolling interests, previously classified as minority interest outside of equity, as part of stockholders equity. In our presentation of consolidated income and stockholders equity we distinguish between amounts attributable to Layne Christensen Company and amounts attributable to the noncontrolling interests. In addition to these financial reporting changes, this guidance provides for significant changes in accounting related to noncontrolling interests; specifically, increases and decreases in our controlling financial interests in consolidated subsidiaries are being reported in equity similar to treasury stock transactions. If a change in ownership of a consolidated subsidiary results in loss of control and deconsolidation, any retained ownership interests will be remeasured with the gain or loss reported in net earnings. The Company adopted this standard, which was applied retrospectively, as of February 1, 2009, and reclassified minority interest in the amounts of $75,000 as of February 1, 2009 and $398,000 as of February 1, 2008, as a component of stockholders equity.

(19) Quarterly Results (Unaudited)
Unaudited quarterly financial data are as follows:

(in thousands, except per share data) 2010	First	Second	Third	Fourth
Revenues	$204,192	$217,227	$217,800	$227,198
Net income (loss) attributable to Layne Christensen Company	996	(8,640)	6,621	2,388
Basic net income (loss) per share	0.05	(0.45)	0.34	0.12
Diluted net income (loss) per share	0.05	(0.45)	0.34	0.12

2009	First	Second	Third	Fourth
Revenues	$244,544	$269,638	$264,483	$229,398
Net income (loss) attributable to Layne Christensen Company	10,562	15,096	12,227	(11,351)
Basic net income (loss) per share	0.55	0.79	0.64	(0.59)
Diluted net income (loss) per share	0.55	0.78	0.63	(0.59)

During the second quarter of 2010, and the fourth quarter of fiscal 2009, the Company recorded a non-cash impairment charge of $21,642,000, or $13,039,000 after income tax and $26,690,000, or $16,081,000 after income tax, respectively, related to its energy operations as a result of its determinations of oil and gas reserves.

Supplemental Information on Oil and Gas Producing Activities (Unaudited)
The Company s oil and gas activities are primarily conducted in the United States. See Note 1 for additional information regarding the Company s oil and gas properties.

Capitalized Costs Related to Oil and Gas Producing Activities
Capitalized costs and associated depletion relating to oil and gas producing activities were as follows at January 31, 2010, 2009 and 2008:

(in thousands)	2010	2009	2008
Oil and gas properties	$ 95,252	$ 92,497	$ 76,844
Mineral interest in oil and gas properties	21,939	21,248	18,165
	117,191	113,745	95,009
Accumulated depletion	(90,492)	(54,859)	(16,353)
Net capitalized costs	$ 26,699	$ 58,886	$ 78,656

Included in accumulated depletion at January 31, 2010 and 2009, were non-cash ceiling test impairments of $21,642,000 and $26,690,000 recorded in 2010 and 2009, respectively. There were no such impairments at January 31, 2008. See Note 4 for additional information regarding impairment of oil and gas properties.

Unproved oil and gas properties at January 31, 2010, 2009 and 2008, totaled $3,851,000, $10,348,000 and $8,131,000, respectively. Unevaluated mineral interest costs excluded from depletion at January 31, 2010, 2009 and 2008, totaled $9,527,000, $9,305,000 and $8,405,000, respectively.

Capitalized costs and associated depreciation relating to gas transportation facilities and equipment were as follows at January 31, 2010, 2009 and 2008:

(in thousands)	2010	2009	2008

Gas transportation facilities and equipment	$40,748	$39,825	$30,266
Accumulated depreciation	(9,535)	(6,831)	(4,355)
Total	$31,213	$32,994	$25,911

Capitalized costs incurred in gas transportation facilities and equipment during 2010, 2009 and 2008 totaled $923,000, $6,739,000 and $5,327,000, respectively. During fiscal 2009, we transferred $2,820,000 from oil and gas properties to gas transportation facilities and equipment as the Company began to use these facilities to transport third party natural gas to market.

Cost Incurred in Oil and Gas Producing Activities

Capitalized costs incurred in oil and gas producing activities were as follows during 2010, 2009 and 2008:

(in thousands)	2010	2009	2008
Acquisition			
Proved	$ 691	$ 2,061	$ 5,647
Unproved			
Exploration		5	1,501
Development	2,649	20,802	16,718
Provision for future asset retirement costs	106	185	170
Total	$3,446	$23,053	$24,036

Exploration costs of $1,498,000 in 2008 were associated with an exploration project in Chile. These costs were considered impaired and written off in 2009.

Results of Operations for Oil and Gas Producing Activities

Results of operations relating to oil and gas producing activities are set forth in the following tables for the years ended January 31, 2010, 2009 and 2008, on a dollar and per Mcf basis and include only revenues and operating costs directly attributable to oil and gas producing activities. General corporate overhead, interest costs, transportation of third party gas and other non oil and gas producing activities are excluded. The income tax expense is calculated by applying statutory tax rates to the revenues after deducting costs, which include depletion allowances.

(in thousands)	2010	2009	2008
Revenues	$ 44,626	$ 43,712	$ 38,222
Production taxes	(334)	(1,034)	(872)
Lease operating expenses	(9,493)	(11,747)	(12,189)
Depletion	(13,992)	(11,816)	(8,504)
Depreciation and amortization	(3,184)	(2,828)	(2,225)
Administrative expenses	(2,688)	(2,131)	(2,670)
Impairment of oil and gas properties	(21,642)	(28,704)	
Income tax (expense) benefit	2,666	5,783	(4,675)
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ (4,041)	$ (8,765)	$ 7,087

(per Mcf)	2010	2009	2008
Revenues	$ 9.66	$ 8.52	$ 8.08
Production taxes	(0.07)	(0.20)	(0.18)
Lease operating expenses	(2.06)	(2.29)	(2.58)
Depletion	(3.03)	(2.30)	(1.80)
Depreciation and amortization	(0.69)	(0.55)	(0.47)
Administrative expenses	(0.58)	(0.42)	(0.56)
Impairment of oil and gas properties	(4.69)	(5.59)	
Income tax (expense) benefit	0.58	1.12	(0.99)
Results of operations from producing activities (excluding corporate overhead and interest costs)	$(0.88)	$(1.71)	$ 1.50

Proved Oil and Gas Reserve Quantities

Proved gas reserve quantities as of January 31, 2010 and 2009 are based on estimates prepared by the Company s independent petroleum engineers, Cawley, Gillespie & Associates, Inc., in accordance with requirements of the SEC. All of the Company s reserves are located within the United States.

Proved gas reserves are estimated quantities of natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under economic and operating conditions in effect when the estimates are made. Proved developed reserves are those reserves expected to be recovered through wells, equipment and operating methods existing when the estimates are made. Proved undeveloped reserves are those reserves expected to be recovered through new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. The Company cautions that there are many inherent uncertainties in estimating quantities of proved reserves and projecting future rates of production and timing of development expenditures. Accordingly, these estimates are likely to change as future information becomes available.

Estimated quantities of total proved gas reserves were as follows:

Proved Developed and Undeveloped Reserves (MMcf)	2010	2009
Balance, beginning of year	16,563	50,052
Purchases of reserves in place		
Revisions of previous estimates	2,618	(33,238)
Extensions, discoveries and other additions	1,981	4,881
Production	(4,618)	(5,132)
Balance, end of year	16,544	16,563
Proved Developed Reserves:		
Beginning of year	16,289	22,794
End of year	16,544	16,289
Proved Undeveloped Reserves:		
Beginning of year	274	27,258
End of year		274

The declines in reserves in 2009, particularly undeveloped reserves, were a result of significantly lower prices used in the estimates. Lower prices decrease the economic lives of the underlying properties and decrease the estimated future reserves.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities

Beginning at our fiscal 2010 year end, the price used in determining future cash inflows for purposes of the standardized measure of discounted future net cash flows is the unweighted arithmetic average of the first-day-of-the-month spot price for each month within the 12-month period to the end of the reporting period. Previously the spot price at the end of the reporting period was used. In both cases, the future cash inflows also incorporate the effect of contractual arrangements such as our fixed-price physical delivery forward sales contracts. The prices used in our determinations at January 31, 2010 and 2009, were $3.24 and $3.29 per Mcf, respectively. Future production and development costs represent the estimated future expenditures to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expense was computed by applying statutory rates to pre-tax cash flows relating to the Company s estimated proved reserves and the difference between book and tax basis of proved properties.

This information does not purport to present the fair market value of the Company s natural gas assets, but does present a standardized disclosure concerning possible future net cash flows that would result under the assumptions used. The following table sets forth unaudited information concerning future net cash flows for natural gas reserves, net of income tax expense:

(in thousands)	2010	2009
Future cash inflows	$ 57,600	$ 82,261
Future production costs	(31,218)	(33,514)
Future development costs		(467)
Future income taxes	1,840	(2,196)
Future net cash flows	28,222	46,084
10% annual discount for estimating timing of cash flows	(4,577)	(5,908)
Standardized measure of discounted future net cash flows	$ 23,645	$ 40,176

The principal sources of change in the standardized measure of discounted future net cash flows were:

(in thousands)	2010	2009
Balance, beginning of year	$ 40,176	$ 86,484
Sales of gas produced, net of production costs	(4,481)	(22,214)
Net changes in prices, net of future production costs	(20,412)	(65,507)
Net changes in estimated future development costs	(2,182)	20,565
Extensions and discoveries, less related costs	6,602	12,799
Purchases of reserves in place		
Net change due to revisions in quantity estimates	3,540	(17,183)
Accretion of discount	2,624	11,319
Net changes in timing and other	(9,397)	(33,398)
Net change in income taxes	4,526	30,761
Previously estimated development costs incurred	2,649	16,550
Aggregate change in standardized measure of discounted future net cash flows for the year	(16,531)	(46,308)
Balance, end of year	$ 23,645	$ 40,176

Layne Christensen Company and Subsidiaries
Schedule II: Valuation and Qualifying Accounts

		Additions			
(in thousands)	Balance at Beginning of Period	Charges to Costs and Expenses	Charges to Other Accounts	Deductions	Balance at End of Period
Allowance for customer receivables:					
Fiscal year ended January 31, 2008	$7,020	$1,205	$336	$ (990)	$7,571
Fiscal year ended January 31, 2009	7,571	2,082	608	(2,383)	7,878
Fiscal year ended January 31, 2010	7,878	1,422	924	(2,799)	7,425

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures. Based on an evaluation of disclosure controls and procedures for the period ended January 31, 2010, conducted under the supervision and with the participation of the Company s management, including the Principal Executive Officer and the Principal Financial Officer, the Company concluded that its disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934 is accumulated and communicated to the Company s management (including the Principal Executive Officer and the Principal Financial Officer) to allow timely decisions regarding required disclosure, and is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms.

Management s Report on Internal Control over Financial Reporting. Management of Layne Christensen Company and subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) of the Exchange Act. Under the supervision and with the participation of the Company s management, including our Principal Executive Officer and Principal Financial Officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based upon the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO Framework).

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore it is possible to design into the process safeguards to reduce, although not eliminate, this risk. The Company s internal control over financial reporting includes such safeguards. Projections of an evaluation of effectiveness of internal control over financial reporting in future periods are subject to the risk that the controls may become inadequate because of conditions, or because the degree of compliance with the Company s policies and procedures may deteriorate.

Based on the evaluation under the COSO Framework, management concluded that the Company s internal control over financial reporting is effective as of January 31, 2010. The Company s independent registered public accounting firm has audited the Consolidated Financial Statements included in this Annual Report on Form 10-K and, as part of their audit, has issued their report on the effectiveness of the Company s internal control over financial reporting as of January 31, 2010. The report is included below.

Changes in Internal Control over Financial Reporting. There were no changes in the Company s internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, its internal control over financial reporting during the fourth fiscal quarter of 2010.

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Layne Christensen Company
Mission Woods, Kansas

We have audited the internal control over financial reporting of Layne Christensen Company and subsidiaries (the Company) as of January 31, 2010, 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 January 31, 2010, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended January 31, 2010, of the Company and our report dated April 1, 2010, expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph related to the change in accounting for oil and gas reserve estimation as described in Note 1 to the consolidated financial statements.

/s/ Deloitte & Touche LLP
Kansas City, Missouri
April 1, 2010

PART III

Item 10. Directors and Executive Officers of the Registrant

The Registrant s Proxy Statement to be used in connection with the Annual Meeting of Stockholders to be held on June 3, 2010, (i) contains, under the caption Election of Directors, certain information relating to the Company s directors and its Audit Committee financial experts required by Item 10 of Form 10-K and such information is incorporated herein by this reference (except that the information set forth under the subcaption Compensation of Directors is expressly excluded from such incorporation), (ii) contains, under the caption Other Corporate Governance Matters, certain information relating to the Company s Code of Ethics required by Item 10 of Form 10-K and such information is incorporated herein by this reference, and (iii) contains, under the caption Section 16(a) Beneficial Ownership Reporting Compliance, certain information required by Item 10 of Form 10-K and such information is incorporated herein by this reference. The information required by Item 10 of Form 10-K as to executive officers is set forth in Item 4A of Part I hereof.

Item 11. Executive Compensation

The Registrant s Proxy Statement to be used in connection with the Annual Meeting of Stockholders to be held June 3, 2010, will contain, under the caption Executive Compensation and Other Information, the information required by Item 11 of Form 10-K and such information is incorporated herein by this reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management

The Registrant s Proxy Statement to be used in connection with the Annual Meeting of Stockholders to be held on June 3, 2010, will contain, under the captions Ownership of Layne Christensen Common Stock, and Equity Compensation Plan Information, the information required by Item 12 of Form 10-K and such information is incorporated herein by this reference.

Item 13. Certain Relationships and Related Transactions

The Registrant s Proxy Statement to be used in connection with the Annual Meeting of Stockholders to be held on June 3, 2010, will contain, under the captions Other Corporate Governance Matters, and Certain Transactions Transactions with Management, the information required by Item 13 of Form 10-K and such information is incorporated herein by this reference.

Item 14. Principal Accounting Fees and Services

The Registrant s Proxy Statement to be used in connection with the Annual Meeting of Stockholders to be held on June 3, 2010, will contain, under the caption Principal Accounting Fees and Services, the information required by Item 14 of Form 10-K and such information is incorporated herein by this reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements, Financial Statement Schedules and Exhibits:

1. Financial Statements:

The financial statements are listed in the index for Item 8 of this Form 10-K.

2. Financial Statement Schedules:

The applicable financial statement schedule is listed in the index for Item 8 of this Form 10-K.

3. Exhibits:

The exhibits filed with or incorporated by reference in this report are listed below:

Exhibit Number	Description
3(1)	Corrected Certificate of Restated Certificate of Incorporation of the Registrant (filed as Exhibit 3(1) with the Registrant s Registration Statement on Form S-1 which was filed on September 20, 2007 (File No.333-146184), and incorporated herein by this reference)
3(2)	Amended and Restated Bylaws of the Registrant (as adopted October 9, 2008) (filed as Exhibit 3.2 to the Registrant s Form 8-K filed October 14, 2008, and incorporated herein by this reference)
4(1)	Certificate of Designations of Series A Junior Participating Preferred Stock of Layne Christensen Company (filed with the Registrant s Annual Report on Form 10-K for the fiscal year ended January 31, 2007 as Exhibit 4(2) and incorporated herein by this reference)
4(2)	Rights Agreement, dated as of October 14, 2008, between the Registrant and National City Bank as Rights Agent, which includes as Exhibit C, the Summary of Rights to Purchase Preferred Shares (filed as Exhibit 4.1 to the Registrant s Form 8-K filed October 14, 2008, and incorporated herein by this reference)
4(3)	Specimen Common Stock Certificate (filed with Amendment No. 3 to the Registrant s Registration Statement on Form S-1 (File No. 33-48432) as Exhibit 4(1) and incorporated herein by reference)
4(4)	Amended and Restated Loan Agreement, dated as of September 28, 2005, by and among Layne Christensen Company, LaSalle Bank National Association, as Administrative Agent and as Lender, and the other Lenders listed therein (filed as Exhibit 4.1 to the Company s Form 8-K, dated September 28, 2005, and incorporated herein by this reference)
4(5)	Amendment No. 1 to Amended and Restated Loan Agreement, dated June 16, 2006, by and among Layne Christensen Company and LaSalle Bank National Association (LaSalle) as Administrative Agent, and LaSalle and the other Lenders a party thereto (filed as Exhibit 10(1) to the Company s Form 10-Q for the quarter ended July 31, 2006, and incorporated herein by this reference)
4(6)	Amendment No. 2 to the Amended and Restated Loan Agreement, dated as of November 20, 2006, by and among Layne Christensen Company and LaSalle, as Administrative Agent, and LaSalle and the other Lenders a party thereto (filed as Exhibit 4(1) to the Company s Form 8-K, dated November 20, 2006, and incorporated herein by this reference)
4(7)	Amendment No. 3 to Amended and Restated Loan Agreement, dated October 15, 2007, by and among the Company, LaSalle Bank National Association, as Administrative Agent and Lender, and the other Lenders listed therein (filed as Exhibit 10(1) to the Company s Form 10-Q for the quarter ended

	October 31, 2007, and incorporated herein by this reference)
4(8)	Amendment No. 4 to Amended and Restated Loan Agreement, dated March 31, 2009, by and among Layne Christensen Company, and Bank of America, N.A. (as successor to LaSalle Bank National Association) (Bank of America), as Administrative Agent, and Bank of America and the other lenders a party hereto comprising the Required Lenders (incorporated by reference to Exhibit 10(1) to the Company s Current Report on Form 8-K filed April 2, 2009)
4(9)	Master Shelf Agreement, dated as of July 31, 2003, by and among Layne Christensen Company, Prudential Investment Management, Inc., The Prudential Insurance Company of America, Pruco Life Insurance Company, Security Life of Denver Insurance Company and such other Purchasers of the Notes as may be named in the Master Shelf Agreement

Item 15. Exhibits and Financial Statement Schedules (continued)

Exhibit Number	Description
	from time to time (filed with the Registrant s 10-Q for the quarter ended July 31, 2003 (File No. 0-20578) as Exhibit 4(5) and incorporated herein by reference)
4(10)	Letter Amendment No. 1 to Master Shelf Agreement, dated as of May 15, 2004, by and among Layne Christensen Company, Prudential Investment Management, Inc., The Prudential Insurance Company of America, Pruco Life Insurance Company, Security Life of Denver Insurance Company and such other Purchasers of the Notes as may be named in the Master Shelf Agreement from time to time (filed as Exhibit 4(6) to the Company s Form 10-K for the fiscal year ended January 31, 2006, and incorporated herein by this reference)
4(11)	Letter Amendment No. 2 to Master Shelf Agreement, dated as of September 28, 2005, by and among Layne Christensen Company, Prudential Investment Management, Inc., The Prudential Insurance Company of America, Pruco Life Insurance Company, Security Life of Denver Insurance Company and such other Purchasers of the Notes as may be named in the Master Shelf Agreement from time to time (filed as Exhibit 4.2 to the Company s Form 8-K, dated September 28, 2005, and incorporated herein by this reference)
4(12)	Letter Amendment No. 3 to Master Shelf Agreement, dated as of June 16, 2006, by and among Layne Christensen Company, Prudential Investment Management, Inc., The Prudential Insurance Company of America, Pruco Life Insurance Company, Security Life of Denver Insurance Company and such other Purchasers of the Notes as may be named in the Master Shelf Agreement from time to time (filed as Exhibit 10(2) to the Company s Form 10-Q for the quarter ended July 31, 2006, and incorporated herein by this reference)
4(13)	Letter Amendment No. 4 to Master Shelf Agreement, dated as of November 20, 2006, by and among Layne Christensen Company, Prudential Investment Management, Inc., The Prudential Insurance Company of America, Pruco Life Insurance Company, Security Life of Denver Insurance Company and such other Purchasers of the Notes as may be named in the Master Shelf Agreement from time to time (filed as Exhibit 4(2) to the Company s Form 8-K, dated November 20, 2006, and incorporated herein by this reference)
4(14)	Letter Amendment No. 5 to Master Shelf Agreement, dated as of October 15, 2007, by and among Layne Christensen Company, Prudential Investment Management, Inc., The Prudential Insurance Company of America, Pruco Life Insurance Company, Security Life of Denver Insurance Company and such other Purchasers of the Notes as may be named in the Master Shelf Agreement from time to time (filed as Exhibit 10(2) to the Company s Form 10-Q for the quarter ended October 31, 2007, and incorporated herein by this reference)
4(15)	Letter Amendment No. 6 to Master Shelf Agreement, dated March 31, 2009, by and among Layne Christensen Company, Prudential Investment Management, Inc., The Prudential Insurance Company of America, Pruco Life Insurance Company, Time Insurance Company and Physicians Mutual Insurance Company (incorporated by reference to Exhibit 10(2) to the Company s Current Report on Form 8-K filed April 2, 2009)

4(16)	Letter Amendment No. 7 to Master Shelf Agreement, dated to be effective as of October 1, 2009, by and among Layne Christensen Company, Prudential Investment Management, Inc., The Prudential Insurance Company of America, Pruco Life Insurance Company, Security Life of Denver Insurance Company, Prudential Annuities Life Assurance Corporate, Prudential Retirement Insurance and Annuity Company and such other Purchasers of the Notes as may be named in the Master Shelf Agreement from time to time (incorporated by reference to Exhibit 4.1 to the Company s Current Report on Form 8-K filed on October 16, 2009).
10(1)	Tax Liability Indemnification Agreement between the Registrant and The Marley Company (filed with Amendment No. 3 to the Registrant s Registration Statement (File No. 33-48432) as Exhibit 10(2) and incorporated herein by reference)
10(2)	Lease Agreement between the Registrant and Parkway Partners, L.L.C. dated December 21, 1994 (filed with the Registrant s Annual Report on Form 10-K for the fiscal year ended January 31, 1995 (File No. 0-20578) as Exhibit 10(2) and incorporated herein by reference)
10(2.1)	First Modification & Ratification of Lease, dated as of February 26, 1996, between Parkway Partners, L.L.C. and the Registrant (filed with the Registrant s Annual Report on Form 10-K for the fiscal year ended January 31, 1996 (File No. 0-20578), as Exhibit 10(2.1) and incorporated herein by this reference)
10(2.2)	Second Modification and Ratification of Lease Agreement between Parkway Partners, L.L.C. and Layne Christensen Company dated April 28, 1997 (filed with the Registrant s Annual Report on Form 10-K for the fiscal year ended January 31, 1999 (File No. 0-20578), as Exhibit 10(2.2) and incorporated herein by this reference)

Item 15. Exhibits and Financial Statement Schedules (continued)

Exhibit Number	Description
10(2.3)	Third Modification and Extension Agreement between Parkway Partners, L.L.C. and Layne Christensen Company dated November 3, 1998 (filed with the Company s 10-Q for the quarter ended October 31, 1998 (File No. 0-20578) as Exhibit 10(1) and incorporated herein by reference)
10(2.4)	Fourth Modification and Extension Agreement between Parkway Partners, L.L.C. and Layne Christensen Company executed May 17, 2000, effective as of December 29, 1998 (filed with the Company s 10-Q for the quarter ended July 31, 2000 (File No. 0-20578) as Exhibit 10.1 and incorporated herein by reference)
10(2.5)	Fifth Modification and extension Agreement between Parkway Partners, L.L.C. and Layne Christensen Company dated March 1, 2003 (filed as Exhibit 10(2.5) to the Registrant s Annual Report on Form 10-K for the fiscal year ended January 31, 2003 (File No. 0-20578) and incorporated herein by this reference)
10(2.6)	Sixth Modification Agreement, dated February 29, 2008, between 1900 Associates L.L.C. and the Company (filed as Exhibit 10(2.6) to the Registrant s Annual Report on Form 10-K for the fiscal year ended January 31, 2008, filed April 15, 2008, and incorporated herein by this reference)
**10(3)	Form of Stock Option Agreement between the Company and management of the Company (filed with Amendment No. 3 to the Registrant s Registration Statement (File No. 33-48432) as Exhibit 10(7) and incorporated herein by reference)
10(4)	Insurance Liability Indemnity Agreement between the Company and The Marley Company (filed with Amendment No. 3 to the Registrant s Registration Statement (File No. 33-48432) as Exhibit 10(10) and incorporated herein by reference)
10(5)	Agreement between The Marley Company and the Company relating to tradename (filed with the Registrant s Registration Statement (File No.33-48432) as Exhibit 10(10) and incorporated herein by reference)
**10(6)	Form of Subscription Agreement for management of the Company (filed with Amendment No. 3 to the Registrant s Registration Statement (File No. 33-48432) as Exhibit 10(16) and incorporated herein by reference)
**10(7)	Form of Subscription Agreement between the Company and Robert J. Dineen (filed with Amendment No. 3 to the Registrant s Registration Statement (File No. 33-48432) as Exhibit 10(17) and incorporated herein by reference)
**10(8)	Letter Agreement between Andrew B. Schmitt and the Company (as amended and restated to comply with Section 409A) dated December 2, 2008 (incorporated by reference to Exhibit 10(8) to the Company s Annual Report on Form 10-K for the fiscal year ended January 31, 2009, filed on March 31, 2009)
**10(9)	Form of Incentive Stock Option Agreement between the Company and Management of the Company (filed with the Company s Annual Report on Form 10-K for the fiscal year ended January 31, 1996 (File No. 0-20578), as Exhibit 10(15) and incorporated herein by this reference)

10(10)	Registration Rights Agreement, dated as of November 30, 1995, between the Company and Marley Holdings, L.P. (filed with the Company s Annual Report on Form 10-K for the fiscal year ended January 31, 1996 (File No. 0-20578), as Exhibit 10(17) and incorporated herein by this reference)
**10(11)	Form of Incentive Stock Option Agreement between the Company and Management of the Company effective February 1, 1998 (filed with the Company s Form 10-Q for the quarter ended April 30, 1998 (File No. 0-20578) as Exhibit 10(1) and incorporated herein by reference)
**10(12)	Form of Incentive Stock Option Agreement between the Company and Management of the Company effective April 20, 1999 (filed with the Company s Form 10-Q for the quarter ended April 30, 1999 (File No. 0-20578) as Exhibit 10(2) and incorporated herein by reference)
**10(13)	Form of Non Qualified Stock Option Agreement between the Company and Management of the Company effective as of April 20, 1999 (filed with the Company s Form 10-Q for the quarter ended April 30, 1999 (File No. 0-20578) as Exhibit 10(3) and incorporated herein by reference)
**10(14)	Layne Christensen Company District Incentive Compensation Plan (revised effective February 1, 2000) (filed as Exhibit 10(17) to the Registrant s Annual Report on Form 10-K for the fiscal year ended January 31, 2003 (File No. 0-20578) and incorporated herein by this reference)
**10(15)	Layne Christensen Company Executive Incentive Compensation Plan (as amended and restated, effective November 3, 2008) (incorporated by reference to Exhibit 10(15) to the Company s Annual Report on Form 10-K for the fiscal year ended January 31, 2009, filed on March 31, 2009)

Item 15. Exhibits and Financial Statement Schedules (continued)

Exhibit Number	**Description**
**10(16)	Layne Christensen Company Corporate Staff Incentive Compensation Plan (as amended, effective February 1, 2007) (incorporated by reference to Exhibit 10(16) to the Company s Annual Report on Form 10-K for the fiscal year ended January 31, 2009, filed on March 31, 2009)
10(17)	Standstill Agreement, dated March 26, 2004, by and among Layne Christensen Company, Wynnefield Partners Small Cap Value, L.P., Wynnefield Small Cap Value Offshore Fund, Ltd., Wynnefield Partners Small Cap Value L.P.I., Channel Partnership II, L.P., Wynnefield Capital Management, LLC, Wynnefield Capital, Inc., Wynnefield Capital, Inc. Profit Sharing s Money Purchase Plan, Nelson Obus and Joshua Landes (filed as Exhibit 10(19) to the Registrant s Annual Report on Form 10-K for the fiscal year ended January 31, 2004 (File No. 0-20578) and incorporated herein by this reference)
**10(18)	Layne Christensen Company 2006 Equity Incentive Plan, as amended (filed as Appendix B to the Company s Definitive Proxy Statement filed with the SEC on May 6, 2009, and incorporated herein by this reference)
**10(19)	Form of Incentive Stock Option Agreement between the Company and management of the Company for use with the 2006 Equity Incentive Plan (filed as Exhibit 4(e) to the Company s Form S-8 (File No. 333-135683), filed July 10, 2006, and incorporated herein by this reference)
**10(20)	Form of Nonqualified Stock Option Agreement between the Company and management of the Company for use with the 2006 Equity Incentive Plan, as amended effective January 26, 2009 (incorporated by reference to Exhibit 10(20) to the Company s Annual Report on Form 10-K for the fiscal year ended January 31, 2009, filed on March 31, 2009)
**10(21)	Form of Nonqualified Stock Option Agreement between the Company and non-employee directors of the Company for use with the 2006 Equity Incentive Plan, as amended effective January 26, 2009 (incorporated by reference to Exhibit 10(21) to the Company s Annual Report on Form 10-K for the fiscal year ended January 31, 2009, filed on March 31, 2009)
**10(22)	Form of Restricted Stock Award Agreement between the Company and management of the Company for use with the 2006 Equity Incentive Plan, as amended effective January 23, 2008 (incorporated by reference to Exhibit 10(22) to the Company s Annual Report on Form 10-K for the fiscal year ended January 31, 2009, filed on March 31, 2009)
**10(23)	Form of Restricted Stock Award Agreement between the Company and management of the Company for use with the 2006 Equity Incentive Plan (with performance vesting) (incorporated by reference to Exhibit 10(1) to the Company s Quarterly Report on Form 10-Q for the quarter ended April 30, 2009, filed on June 3, 2009)
**10(24)	Form of Restricted Stock Award Agreement between the Company and non-employee directors of the Company for use with the Company s 2006 Equity Incentive Plan, as amended effective January 26, 2009 (incorporated by reference to Exhibit 10(23) to the Company s Annual Report on Form 10-K for the fiscal year ended January 31, 2009, filed on March 31, 2009)

**10(25)	Layne Christensen Company Water Infrastructure Division Incentive Compensation Plan (as amended and restated, effective February 1, 2008) (incorporated by reference to Exhibit 10(24) to the Company s Annual Report on Form 10-K for the fiscal year ended January 31, 2008, filed April 15, 2008)
**10(26)	Layne Energy, Inc. 2007 Stock Option Plan (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed June 13, 2007)
**10(27)	Form of Nonqualified Stock Option Agreement under the Layne Energy, Inc. 2007 Stock Option Plan (incorporated by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed June 13, 2007)
**10(28)	Layne Christensen Company Mineral Exploration Division Incentive Compensation Plan (as amended and restated effective February 1, 2008) (incorporated by reference to Exhibit 10(27) to the Company s Annual Report on Form 10-K for the fiscal year ended January 31, 2008, filed April 15, 2008)
**10(29)	Severance Agreement, dated March 13, 2008, by and between Andrew B. Schmitt and Layne Christensen Company (incorporated by reference to Exhibit 10(1) to the Company s Current Report on Form 8-K filed March 19, 2008)
**10(30)	Severance Agreement, dated March 13, 2008, by and between Gregory F. Aluce and Layne Christensen Company (incorporated by reference to Exhibit 10(2) to the Company s Current Report on Form 8-K filed March 19, 2008)
**10(31)	Severance Agreement, dated March 13, 2008, by and between Steven F. Crooke and Layne Christensen Company (incorporated by reference to Exhibit 10(3) to the Company s Current Report on Form 8-K filed March 19, 2008)
**10(32)	Severance Agreement, dated March 13, 2008, by and between Jerry W. Fanska and Layne Christensen Company (incorporated by reference to Exhibit 10(4) to the Company s Current Report on Form 8-K filed March 19, 2008)

Item 15. Exhibits and Financial Statement Schedules (continued)

Exhibit Number	Description
**10(33)	Severance Agreement, dated March 13, 2008, by and between Jeffrey J. Reynolds and Layne Christensen Company (incorporated by reference to Exhibit 10(5) to the Company s Current Report on Form 8-K filed March 19, 2008)
**10(34)	Severance Agreement dated July 10, 2008, by and between Eric R. Despain and Layne Christensen Company (incorporated by reference to Exhibit 10(1) to the Company s Current Report on Form 8-K filed July 14, 2008)
**10(35)	Summary of 2010 Salaries of Named Executive Officers and Compensation of Directors
10(36)	Agreement and Plan of Merger, dated August 30, 2005, among Layne Christensen Company, Layne Merger Sub 1, Inc., Reynolds, Inc. and the Stockholders of Reynolds, Inc. listed on the signature pages thereto (filed as Exhibit 10.2 to the Company s Form 8-K, dated September 28, 2005, and incorporated herein by this reference)
10(37)	Amendment to Agreement and Plan of Merger, dated July 30, 2007, by and among the Company and Jeffrey Reynolds, individually and as Agent of the Stockholders listed on the signature pages thereto (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed August 3, 2007)
**10(38)	Layne Christensen Company Deferred Compensation Plan for Directors (Amended and Restated, effective as of January 1, 2009) (incorporated by reference to Exhibit 10(37) to the Company s Annual Report on Form 10-K for the fiscal year ended January 31, 2009, filed on March 31, 2009)
**10(39)	Amended and Restated Layne Christensen Company Key Management Deferred Compensation Plan, effective as of January 1, 2008 (incorporated by reference to Exhibit 10(38) to the Company s Annual Report on Form 10-K for the fiscal year ended January 31, 2009, filed on March 31, 2009)
**10(40)	Reynolds Division of Layne Christensen Company Cash Bonus Plan, dated September 28, 2005 (filed as Exhibit 10.1 to the Company s Form 8-K, dated September 28, 2005, and incorporated herein by this reference)
10(41)	Settlement Agreement, dated March 31, 2006, by and among Layne Christensen Company, Steel Partners II, L.P., Steel Partners, L.L.C. and Warren G. Lichtenstein (filed as Exhibit 10.1 to the Company s Form 8-K, dated April 5, 2006, and incorporated herein by this reference)
10(42)	Form of Indemnification Agreement for use in connection with the Rights Agreement dated October 14, 2008 (filed as Exhibit 10.1 to the Registrant s Form 8-K filed October 14, 2008, and incorporated herein by this reference)
21(1)-	List of Subsidiaries
23(1)-	Consent of Deloitte & Touche LLP

23(2)-	Consent of Deloitte
23(3)-	Consent of Cawley, Gillespie & Associates, Inc.
31(1)-	Section 302 Certification of Principal Executive Officer of the Company
31(2)-	Section 302 Certification of Principal Financial Officer of the Company
32(1)-	Section 906 Certification of Principal Executive Officer of the Company
32(2)-	Section 906 Certification of Principal Financial Officer of the Company
99(1)-	Report of Cawley, Gillespie & Associates, Inc.
99(2)-	Financial statements of equity affiliate Geotec Boyles Bros., S.A

** Management contracts or compensatory plans or arrangements required to be identified by Item 14(a)(3).

(b) Exhibits

The exhibits filed with this report on Form 10-K are identified above under Item 15(a)(3).

(c) Financial Statement Schedules

Financial statements of Geotec Boyles Bros., S.A. are included as exhibit 99(2) under Item 15(a)(3).

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.

Layne Christensen Company

By /s/ A. B. Schmitt
Andrew B. Schmitt
President and Chief Executive Officer:

Dated April 1, 2010

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 and Title	Date
/s/ A. B. Schmitt	April 1, 2010
Andrew B. Schmitt President, Chief Executive Officer and Director (Principal Executive Officer)	
/s/ Jerry W. Fanska	April 1, 2010
Jerry W. Fanska Senior Vice President-Finance and Treasurer (Principal Financial and Accounting Officer)	
/s/ Jeff Reynolds	April 1, 2010
Jeffrey J. Reynolds Director	
/s/ David A. B. Brown	April 1, 2010
David A. B. Brown Director	
/s/ J. Samuel Butler	April 1, 2010
J. Samuel Butler Director	
/s/ Anthony B. Helfet	April 1, 2010

Anthony B. Helfet
Director

/s/ Nelson Obus	April 1, 2010

Nelson Obus
Director

/s/ Rene Robichaud	April 1, 2010

Rene Robichaud
Director

/s/ Robert Gilmore	April 1, 2010

Robert Gilmore
Director