NABORS INDUSTRIES LTD
Form 10-K
March 01, 2013
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2012

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 001-32657

NABORS INDUSTRIES LTD.

(Exact name of registrant as specified in its charter)

Bermuda	**980363970**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

Crown House, Second Floor
4 Par-la-Ville Road
Hamilton, HM08
Bermuda
(Address of principal executive offices)

N/A
(Zip Code)

(441) 292-1510

(Registrant s telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Securities Exchange Act of 1934:

Title of each class	Name of each exchange on which registered
Common shares, $.001 par value per share	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Securities Exchange Act of 1934:

None.

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

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 x

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 x NO o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, 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. YES x 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. x

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.

Large Accelerated Filer x	Accelerated Filer o
Non-accelerated Filer o	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 x

The aggregate market value of the 275,797,408 common shares, par value $.001 per share, held by non-affiliates of the registrant, based upon the closing price of our common shares as of the last business day of our most recently completed second fiscal quarter, June 29, 2012, of $14.40 per share as reported on the New York Stock Exchange, was $3,971,482,675. Common shares held by each officer and director and by each person who owns 5% or more of the outstanding common shares have been excluded in that such persons may be deemed affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

The number of common shares, par value $.001 per share, outstanding as of February 25, 2013 was 291,036,865.

DOCUMENTS INCORPORATED BY REFERENCE (to the extent indicated herein)

Specified portions of the definitive Proxy

Statement to be distributed in connection with our 2013 Annual General Meeting of Shareholders (Part III).

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NABORS INDUSTRIES LTD.

Form 10-K Annual Report

For the Year Ended December 31, 2012

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Our internet address is *www.nabors.com*. We make available free of charge through our website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the Exchange Act), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission (the SEC). In addition, a glossary of drilling terms used in this document and documents relating to our corporate governance (such as committee charters, governance guidelines and other internal policies) can be found on our website. The SEC maintains an internet site (*www.sec.gov*) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

FORWARD-LOOKING STATEMENTS

We often discuss expectations regarding our future markets, demand for our products and services, and our performance in our annual and quarterly reports, press releases, and other written and oral statements. Statements relating to matters that are not historical facts are forward-looking statements within the meaning of the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended (the Securities Act), and Section 21E of the Exchange Act. These forward-looking statements are based on an analysis of currently available competitive, financial and economic data and our operating plans. They are inherently uncertain and investors should recognize that events and actual results could turn out to be significantly different from our expectations. By way of illustration, when used in this document, words such as anticipate, believe, expect, plan, intend, estimate, project, will, should, could, may, predict and similar expressions ar forward-looking statements.

You should consider the following key factors when evaluating these forward-looking statements:

- fluctuations in worldwide prices of and demand for oil and natural gas;
- fluctuations in levels of oil and natural gas exploration and development activities;
- fluctuations in the demand for our services;
- the existence of competitors, technological changes and developments in the oilfield services industry;
- the existence of operating risks inherent in the oilfield services industry;
- the possibility of changes in tax and other laws and regulations;

- the possibility of political instability, war or acts of terrorism; and
- general economic conditions including the capital and credit markets.

Our businesses depend to a large degree on the level of spending by oil and gas companies for exploration, development and production activities. Therefore, a sustained increase or decrease in the price of oil or natural gas that has a material impact on exploration, development or production activities could also materially affect our financial position, results of operations and cash flows.

The above description of risks and uncertainties is not all-inclusive, but highlights certain factors that we believe are important for your consideration. For a more detailed description of risk factors, please refer to Part I, Item 1A. *Risk Factors.*

Unless the context requires otherwise, references in this report to we, us, our, the Company, or Nabors mean Nabors Industries Ltd., together with our subsidiaries where the context requires, including Nabors Industries, Inc., a Delaware corporation (Nabors Delaware), our wholly owned subsidiary.

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PART I

ITEM 1. *BUSINESS*

Introduction

Nabors is the largest land drilling contractor in the world and one of the largest land well-servicing and workover contractors in the United States and Canada:

- We actively market approximately 474 land drilling rigs for oil and gas land drilling operations in the U.S. Lower 48 states, Alaska, Canada and over 20 other countries throughout the world.

- We actively market approximately 442 rigs for land well-servicing and workover work in the United States and approximately 106 rigs for land well-servicing and workover work in Canada.

We are also a leading provider of offshore platform workover and drilling rigs, and actively market 36 platform, 12 jackup and 4 barge rigs in the United States, including the Gulf of Mexico, and multiple international markets.

In addition to the foregoing services:

- We provide completion and production services, including hydraulic fracturing, cementing, nitrogen and acid pressure pumping services with over 805,000 hydraulic horsepower in key basins throughout the United States and Canada.

- We offer a wide range of ancillary well-site services, including engineering, transportation and disposal, construction, maintenance, well logging, directional drilling, rig instrumentation, data collection and other support services in select U.S. and international markets.

- We manufacture and lease or sell top drives for a broad range of drilling applications, directional drilling systems, rig instrumentation and data collection equipment, pipeline handling equipment and rig reporting software.

- We have a 51% ownership interest in a joint venture in Saudi Arabia, which owns and actively markets nine rigs in addition to the rigs we lease to the joint venture.

Nabors was formed as a Bermuda exempted company on December 11, 2001. Through predecessors and acquired entities, Nabors has been continuously operating in the drilling sector since the early 1900s. Our principal executive offices are located at Crown House, 4 Par-la-Ville Road, Second Floor, Hamilton, HM08, Bermuda, and our phone number there is (441) 292-1510.

Our Rig Fleet

- *Land Rigs*. A land-based drilling rig generally consists of engines, a drawworks, a mast (or derrick), pumps to circulate drilling fluid under various pressures, blowout preventers, drill string and related equipment. The engines power the different pieces of equipment, including a rotary table or top drive that turns the drill string, causing the drill bit to bore through the subsurface rock layers. Rock cuttings are carried to the surface by the circulating drilling fluid. The intended well depth, bore hole diameter and drilling site conditions are the principal factors that determine the size and type of rig most suitable for a particular drilling job.

Special-purpose drilling rigs used to perform workover services consist of a mobile carrier, which includes an engine, drawworks and a mast, together with other standard drilling accessories and specialized equipment for servicing wells. These rigs are specially designed for major repairs and modifications of oil and gas wells, including standard drilling functions. A well-servicing rig is specially designed for periodic maintenance of oil and gas wells for which service is required to maximize the productive life of the wells. The primary function of a well-servicing rig is to act as a hoist so that pipe, sucker rods and down-hole equipment can be run into and out of a well, although they also can perform standard drilling functions. Because of size and cost considerations, these specially designed rigs are used for these operations rather than larger drilling rigs typically used for initial drilling.

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Land-based drilling rigs are moved between well sites and among geographic areas using our fleet of cranes, loaders and transport vehicles or those of third-party service providers. Well-servicing rigs are typically self-propelled, while heavier capacity workover rigs are either self-propelled or trailer-mounted and include auxiliary equipment, which is either transported on trailers or moved with trucks.

- *Platform Rigs*. Platform rigs provide offshore workover, drilling and re-entry services. Our platform rigs have drilling and/or well-servicing or workover equipment and machinery arranged in modular packages that are transported to, and assembled and installed on, fixed offshore platforms owned by the customer. Fixed offshore platforms are steel tower-like structures that either stand on the ocean floor or are moored floating structures. The top portion, or platform, sits above the water level and provides the foundation upon which the platform rig is placed.

- *Jackup Rigs*. Jackup rigs are mobile, self-elevating drilling and workover platforms equipped with legs that can be lowered to the ocean floor until a foundation is established to support the hull, which contains the drilling and/or workover equipment, jacking system, crew quarters, loading and unloading facilities, storage areas for bulk and liquid materials, helicopter landing deck and other related equipment. The rig legs may operate independently or have a mat attached to the lower portion of the legs in order to provide a more stable foundation in soft bottom areas. Many of our jackup rigs are of cantilever design a feature that permits the drilling platform to be extended out from the hull, allowing it to perform drilling or workover operations over adjacent, fixed platforms. Our shallow workover jackup rigs are typically limited to a maximum water depth of approximately 125 feet, and some may drill in water depths as shallow as 13 feet. We also have deeper water jackup rigs capable of drilling at depths between eight feet and 150 to 250 feet. The water depth limit of a particular rig is determined by the length of its legs and by the operating environment. Moving a rig from one drill site to another involves lowering the hull down into the water until it is afloat and then jacking up its legs. The rig is then towed to the new drilling site.

- *Inland Barge Rigs*. One of Nabors barge rigs is a full-size drilling unit. We also own two workover inland barge rigs. These barges are designed to perform plugging and abandonment, well-service or workover services in shallow inland, coastal or offshore waters. Our barge rigs can operate at depths between three and 20 feet.

Additional information regarding the geographic markets in which we operate and our business segments can be found in Note 22 Segment Information in Part II, Item 8. Financial Statements and Supplementary Data.

Types of Drilling Contracts

In the U.S. Lower 48 states and Canada, we typically enter into contracts for land-based drilling with durations ranging from one to three years. Under these contracts, our rigs are committed to one customer. Our more recent contracts for newly constructed rigs have multi-year terms. Contracts relating to offshore drilling and land drilling in Alaska and international markets generally have one- to five-year terms. Offshore workover projects are often contracted on a single-well basis. We generally receive drilling contracts through competitive bidding, although we occasionally enter into contracts by direct negotiation. Most of our single-well contracts are subject to termination by the customer on short notice, but some can be firm for a number of wells or a period of time, and may provide for early termination compensation in certain circumstances. Contract terms and rates differ depending on a variety of factors, including competitive conditions, the geographical area, the geological formation to be drilled, the equipment and services to be supplied, the on-site drilling conditions and the anticipated duration of the work to be performed.

In recent years, most of our drilling contracts have been daywork contracts. A daywork contract generally provides for a basic rate per day when drilling (the dayrate for our providing a rig and crew) and for lower rates when the rig is moving, or when drilling operations are interrupted or restricted by equipment breakdowns, adverse weather conditions or other conditions beyond our control. In addition, daywork contracts may provide for a lump-sum fee for the mobilization and demobilization of the rig, which in most cases approximates our incurred costs. A daywork contract differs from a footage contract (in which the drilling contractor is paid on the basis of a rate per foot drilled) and a turnkey contract (in which the drilling contractor is paid for drilling a well to a specified depth for a fixed price).

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Completion Services

We provide a wide range of wellsite solutions to oil and natural gas companies, consisting primarily of technical pumping services, including hydraulic fracturing, a process sometimes used in the completion of oil and gas wells whereby water, sand and chemicals are injected under pressure into subsurface formations to stimulate gas and oil production, and down-hole surveying services. The completion process may involve selectively perforating the well casing at the depth of discrete producing zones, stimulating and testing these zones and installing down-hole equipment. The completion process may take a few days to several weeks. We are paid an hourly rate and work is generally performed seven days a week, 24 hours a day.

Other technical services include completion, production and rental tool services. Additionally, we provide fluid logistics services, including those related to the transportation, storage and disposal of fluids that are used in the drilling, development and production of hydrocarbons.

In 2012, approximately 3.3% of revenues from our Completion Services operating segment came from a Nabors consolidated entity and an unconsolidated Nabors affiliate. Our proportionate share of any profits resulting from sales to affiliates were eliminated in consolidation.

U.S. Production Services

Although some wells in the United States flow oil to the surface without mechanical assistance, most are in mature production areas that require pumping or some other form of artificial lift. Pumping wells characteristically require more maintenance than flowing wells because of the mechanical pumping equipment.

- *Well-servicing/Maintenance Services*. We provide maintenance services on the mechanical apparatus used to pump or lift oil from producing wells. These services include, among other activities, repairing and replacing pumps, sucker rods and tubing. They also occasionally include drilling services. We provide the rigs, equipment and crews for these tasks, which are performed on both oil and natural gas wells, but which are more commonly required on oil wells. Maintenance services typically take less than 48 hours to complete. Rigs generally are provided to customers on a call-out basis. We are paid an hourly rate, and work typically is performed five days a week during daylight hours.

- *Workover Services*. Producing oil and natural gas wells occasionally require major repairs or modifications, called workovers. Workovers may be required to remedy failures, modify well depth and formation penetration to capture hydrocarbons from alternative formations, clean out and recomplete a well when production has declined, repair leaks or convert a depleted well to an injection well for secondary or enhanced recovery projects. Workovers normally are carried out with a rig that includes standard drilling accessories such as rotary drilling equipment, pumps and tanks for drilling fluids, blowout preventers and other specialized equipment for servicing rigs. A workover may last anywhere from a few days to several weeks. We are paid a daily rate and work is generally performed seven days a week, 24 hours a day.

- *Production and Other Specialized Services*. We can also provide other specialized services, including onsite temporary fluid storage; the supply, removal and disposal of specialized fluids used during certain completion and workover operations; and the removal and disposal of salt water that often accompanies the production of oil and natural gas. We also provide plugging services for wells where the oil and natural gas has been depleted or further production has become uneconomical. We are paid an hourly or a per-unit rate, as applicable, for these services.

Oil and Gas Investments

In 2007, we began investing in oil and gas exploration, development and production operations in the United States, Canada and Colombia. We had wholly owned operations as well as three unconsolidated joint ventures, which were accounted for by the equity method in these geographic areas.

During 2010, we began marketing our oil and gas assets in Canada and Colombia. During the fourth quarter of 2011, we announced our intention to dispose of virtually all of our remaining oil and gas investment portfolio. We sold some of these assets in 2011 and 2012, and continue marketing others.

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Additional information about our oil and gas activities can be found in Part II, Item 2. Properties and Item 8. Notes 4 Discontinued Operations and our Schedule for Supplemental Information on Oil and Gas Exploration and Production Activities.

Other Services

Through various subsidiaries, we manufacture top drives and catwalks, which are installed on both onshore and offshore drilling rigs. We provide heavy equipment to move drilling rigs, water, other fluids and construction materials as well as the means to move such equipment. We offer specialized drilling technologies, including patented steering systems and rig instrumentation software systems including:

- ROCKITTM directional drilling system, which is used to provide data collection services to oil and gas exploration and service companies, and

- RIGWATCHTM software, which is computerized software and equipment that monitors a rig s real-time performance and daily reporting for drilling operations, making this data available through the internet.

Our Customers

Our customers include major, national and independent oil and gas companies. No customer accounted for more than 10% of our consolidated revenues in 2012 or 2011.

Our Employees

As of December 31, 2012, we employed approximately 27,500 people, of whom approximately 3,000 were employed by unconsolidated affiliates. We believe our relationship with our employees is generally good.

Some rig employees in Alaska, Argentina and Australia are represented by collective bargaining units.

Seasonality

Our Canada and Alaska drilling and workover operations are subject to seasonal variations as a result of weather conditions and generally experience reduced levels of activity and financial results during the second quarter of each year. In addition, our pressure pumping operations located in the Appalachian, Mid-Continent, and Rocky Mountain regions of the United States can be adversely affected by seasonal weather conditions, primarily in the spring, as many municipalities impose weight restrictions on the paved roads leading to our jobsites due to the muddy conditions caused by spring thaws. Global warming could lengthen these periods of reduced activity, but we cannot currently estimate to what degree. Our overall financial results reflect the seasonal variations experienced in these operations, but seasonality does not materially impact the remaining portions of our business.

Research and Development

Research and development continues to be a growing part of our overall business. The effective use of technology is critical to maintaining our competitive position within the drilling industry. We expect to continue developing technology internally and acquiring technology through strategic acquisitions.

Industry/Competitive Conditions

To a large degree, our businesses depend on the level of capital spending by oil and gas companies for exploration, development and production activities. A sustained increase or decrease in the price of oil and natural gas could have a material impact on the exploration, development and production activities of our customers and could materially affect our financial position, results of operations and cash flows. See Part I, Item 1A. Risk Factors *Fluctuations in oil and natural gas prices could adversely affect drilling activity and our revenues, cash flows and profitability*.

Our industry remains competitive. The number of available rigs exceeds demand in many of our markets, resulting in strong price competition. Many rigs can be readily moved from one region to another in response to changes in levels of activity, which may result in an oversupply of rigs in an area. Many of the total available contracts are currently awarded on a bid basis, which further increases competition based on price. The land drilling, workover, pressure pumping and well-servicing market is generally more competitive than the offshore market due to the larger number of rigs and market participants.

In all of our geographic markets, we believe price and the availability and condition of equipment are the most significant factors in determining which drilling contractor is awarded a job. Other factors include the availability of trained personnel possessing the required specialized skills; the overall quality of service and safety record; and the ability to offer ancillary services. Increasingly, the ability to deliver rigs with new technology and features is becoming a competitive factor as are rigs equipped with moving systems and configured to accommodate the drilling of multiple wells on a single site. In international markets, experience in operating in certain environments, as well as customer alliances, have been factors in the selection of Nabors.

Certain competitors are present in more than one of our operating regions, although no one competitor operates in all of these areas. In the U.S. Lower 48 states, we compete with Helmerich and Payne, Inc. and Patterson-UTI Energy, Inc., and several hundred other competitors with national, regional or local rig operations. In our U.S. Production Services operating segment, we compete with Basic Energy Services, Inc., Key Energy Services, Inc., Superior Energy Services, Inc. (formerly, Complete Energy Services, Inc.), Forbes Energy Services Ltd. and numerous other competitors having smaller regional or local rig operations. In Canada and U.S. Offshore, we compete with many firms of varying size, several of which have more significant operations in those areas than Nabors. Elsewhere, we compete directly with various contractors at each location where we operate. Our Completion Services operating segment competes with large operators such as Halliburton, Baker Hughes, Weatherford International Ltd., Schlumberger Limited, and FTS International Services LLC as well as smaller companies such as C&J Energy Services, Inc., RPC, Inc. and other small and mid-sized independent contractors, as well as major oilfield services companies with operations outside of the United States. We believe that the market for land drilling, well-servicing and workover and pressure pumping contracts will continue to be competitive for the foreseeable future.

Our other operating segments represent a relatively smaller part of our business, and we have numerous competitors in each area.

Our Business Strategy

Our strategy is to position Nabors to grow and prosper when market conditions are good and to mitigate adverse effects when market conditions are bad. During 2012, we sought to strengthen our balance sheet, which enhances stability, reduces our borrowing costs and allows us to better navigate challenges and capitalize on market opportunities. In addition to the foregoing, the principal elements of our strategy to build shareholder value are to:

- Leverage our global infrastructure;
- Achieve superior health, safety and environmental performance;

- Achieve superior operational performance;
- Focus on delivering value-added services to our customers;
- Enhance and leverage our technology position; and
- Achieve returns well above our cost of capital.

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During 2012, we formed two business lines to provide a solid foundation for sustained long-term growth, leveraging the benefits of our size and becoming a more customer-focused organization. We believe the deployment of our newer and higher-margin rigs under long-term contracts will also enhance our competitive position.

Our current focus is to continue improving flexibility in our balance sheet, optimize capital deployment and continue to incorporate value enhancing technology and innovation. In addition, we continue to:

- Emphasize execution and operational excellence in our core businesses;
- Impose more stringent investment criteria for new projects;
- Optimize intra-company synergies and technological advancements; and
- Monetize nonperforming and nonstrategic assets.

Acquisitions and Divestitures

We have grown from a land drilling business centered in the U.S. Lower 48 states, Canada and Alaska to an international business with operations on land and offshore in most of the major oil and gas markets in the world. At the beginning of 1990, our fleet consisted of 44 actively marketed land drilling rigs in Canada, Alaska and in various international markets. Today, our worldwide fleet of actively marketed rigs consists of 474 land drilling rigs, 548 rigs for land well-servicing and workover work in the United States and Canada, offshore platform rigs, jackup units, barge rigs and a large component of trucks and fluid hauling vehicles. This growth was fueled in part by strategic acquisitions. Although Nabors continues to examine opportunities, there can be no assurance that attractive rigs or other acquisition opportunities will continue to be available, that the pricing will be economical or that we will be successful in making such acquisitions in the future.

As noted above, we may sell a subsidiary or group of assets outside of our core markets or business if it is strategically or economically advantageous for us to do so.

Acquisitions

In September 2010, we acquired through a tender offer and merger all of the outstanding common stock of Superior Well Services, Inc. (Superior) at a cash purchase price of $22.12 per share, or approximately $681.3 million in the aggregate. The purchase price was allocated to the net tangible and intangible assets acquired and liabilities assumed based on their fair value at the acquisition date. The excess of the purchase price over such fair values was $335.0 million and was recorded as goodwill. Our added services include a wide range of wellsite solutions to oil and natural gas companies, primarily technical pumping services and down-hole surveying services. During 2012, we ceased using the Superior trade name, and in May 2012, we renamed the entity Nabors Completion and Production Services (NCPS) and we merged our U.S. Production Services.

In December 2010, we purchased the business of Energy Contractors LLC (Energy Contractors) for a total cash purchase price of $53.4 million. The assets were comprised of vehicles and rig equipment and are included in our U.S. Production Services operating segment. The purchase price was allocated to the net tangible and intangible assets acquired based on their preliminary fair value estimates as of December 31, 2010. The excess of the purchase price over the fair value of the assets acquired was recorded as goodwill in the amount of $4.2 million.

In July 2011, we paid $65 million in cash to acquire the remaining 50 percent equity interest of Peak, making it a wholly owned subsidiary. Previously, we held a 50 percent equity interest with a carrying value of $38.1 million that we had accounted for as an equity method investment. As a result of the acquisition, we consolidated the assets and liabilities of Peak during the third quarter of 2011 based on their respective fair values. The excess of the estimated fair value of the assets and liabilities over the net carrying value of our previously held equity interest

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resulted in a gain of $13.1 million and is reflected in losses (gains) on sales and disposals of long-lived assets and other expense (income) for 2011. The excess of the purchase price over the fair value was $8.0 million and was recorded as goodwill.

Divestitures

In 2011, we sold some of our wholly owned oil and gas assets in Colombia and our 25% working interest in the Cat Canyon and West Cat Canyon fields in Santa Barbara County, California. Additionally in 2011, Remora Energy International LP (Remora), a former unconsolidated oil and gas joint venture, completed sales of its oil and gas assets in Colombia. During 2011, we received gross cash proceeds of $303.8 million from sales of oil and gas assets.

In 2012, we sold our remaining wholly owned oil and gas business in Colombia and sold additional wholly owned assets in the United States. In December 2012, we sold our 49.7% ownership interest in NFR Energy LLC (NFR Energy), the U.S. unconsolidated oil and gas joint venture, to the remaining equity owners. Subsequent to this transaction, NFR Energy changed its name to Sabine Oil & Gas LLC (Sabine). During 2012, we received cumulative gross cash proceeds of $254.5 million from sales of oil and gas assets.

The accompanying consolidated statements of income (loss) and notes to the consolidated financial statements have been updated to retroactively reclassify the operating results of the divested assets as discontinued operations for all periods presented. See Note 4 Assets Held for Sale and Discontinued Operations for additional discussion in Part II, Item 8. Financial Statements and Supplementary Data.

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Environmental Compliance

We do not currently anticipate that compliance with currently applicable environmental regulations and controls will significantly change our competitive position, capital spending or earnings during 2013. We believe we are in material compliance with applicable environmental rules and regulations, and the cost of such compliance is not material to our business or financial condition. For a more detailed description of the environmental laws and regulations applicable to our operations, see Part I, Item 1A. Risk Factors *Changes to or noncompliance with governmental regulation or exposure to environmental liabilities could adversely affect our results of operations.*

ITEM 1A. *RISK FACTORS*

In addition to the other information set forth elsewhere in this report, the following factors should be carefully considered when evaluating Nabors. The risks described below are not the only ones we face. Additional risks not presently known to us or that we currently deem immaterial may also impair our business operations.

Our business, financial condition or results of operations could be materially adversely affected by any of these risks.

Fluctuations in oil and natural gas prices could adversely affect drilling activity and our revenues, cash flows and profitability

Our operations depend on the level of spending by oil and gas companies for exploration, development and production activities. Both short-term and long-term trends in oil and natural gas prices affect these levels. Oil and natural gas prices, as well as the level of drilling, exploration and production activity, can be highly volatile. Worldwide military, political and economic events, including initiatives by the Organization of Petroleum Exporting Countries, affect both the demand for, and the supply of, oil and natural gas. Weather conditions, governmental regulation (both in the United States and elsewhere), levels of consumer demand, the availability of pipeline capacity, and other factors beyond our control may also affect the supply of and demand for oil and natural gas. Lower oil and natural gas prices have caused some of our customers to terminate, seek to renegotiate or fail to honor our drilling contracts and affected the fair market value of our rig fleet, which in turn has resulted in impairments of our assets. A sustained or further decline in oil and natural gas prices could adversely impact our cash forecast models used to determine whether the carrying value of our long-lived assets exceed our future cash flows, which could result in future impairment to our long-lived assets. A prolonged period of lower oil and natural gas prices could affect our ability to retain skilled rig personnel and affect our ability to access capital to finance and grow our business. There can be no assurances as to the future level of demand for our services or future conditions in the oil and natural gas and oilfield services industries.

We operate in a highly competitive industry with excess drilling capacity, which may adversely affect our results of operations

The oilfield services industry is very competitive. Contract drilling companies compete primarily on a regional basis, and competition may vary significantly from region to region at any particular time. Many drilling, workover and well-servicing rigs can be moved from one region to another in response to changes in levels of activity and market conditions, which may result in an oversupply of rigs in an area. In many markets where we operate, the number of rigs available for use exceeds the demand for rigs, resulting in price competition. Most drilling and workover contracts are awarded on the basis of competitive bids, which also results in price competition. The land drilling market generally is more competitive than the offshore drilling market because there are larger numbers of rigs and competitors.

The nature of our operations presents inherent risks of loss that could adversely affect our results of operations

Our operations are subject to many hazards inherent in the drilling, workover and well-servicing and pressure pumping industries, including blowouts, cratering, explosions, fires, loss of well control, loss of or damage to the wellbore or underground reservoir, damaged or lost drilling equipment and damage or loss from inclement weather or natural disasters. Any of these hazards could result in personal injury or death, damage to or destruction of equipment and facilities, suspension of operations, environmental and natural resources damage and damage to the property of others. Our offshore operations are also subject to the hazards of marine operations including capsizing,

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grounding, collision, damage from hurricanes and heavy weather or sea conditions and unsound ocean bottom conditions. Our operations are also subject to risks of war, civil disturbances or other political events.

Accidents may occur, we may be unable to obtain desired contractual indemnities, and our insurance may prove inadequate in certain cases. The occurrence of an event not fully insured or indemnified against, or the failure or inability of a customer or insurer to meet its indemnification or insurance obligations, could result in substantial losses. In addition, insurance may not be available to cover any or all of these risks. Even if available, insurance may be inadequate or insurance premiums or other costs may rise significantly in the future making insurance prohibitively expensive. We expect to continue to face upward pressure in our insurance renewals; our premiums and deductibles may be higher, and some insurance coverage may either be unavailable or more expensive than it has been in the past. Moreover, our insurance coverage generally provides that we assume a portion of the risk in the form of a deductible or self-insured retention. We may choose to increase the levels of deductibles (and thus assume a greater degree of risk) from time to time in order to minimize our overall costs.

The profitability of our operations could be adversely affected by war, civil disturbance, terrorist activity or other political or economic turmoil, fluctuation in currency exchange rates and local import and export controls

We derive a significant portion of our business from global markets, including major operations in South America, Mexico, the Middle East, the Far East, the South Pacific, Russia and Africa. These operations are subject to various risks, including war, civil disturbances, terrorist activity and governmental actions that may limit or disrupt markets, restrict the movement of funds or result in the deprivation of contract rights or the taking of property without fair compensation. In some countries, our operations may be subject to the additional risk of fluctuating currency values and exchange controls. We are subject to various laws and regulations that govern the operation and taxation of our business and the import and export of our equipment from country to country, the imposition, application and interpretation of which can prove to be uncertain.

As a holding company, we depend on our subsidiaries to meet our financial obligations

We are a holding company with no significant assets other than the stock of our subsidiaries. In order to meet our financial needs, we rely exclusively on repayments of interest and principal on intercompany loans that we have made to our operating subsidiaries and income from dividends and other cash flow from our subsidiaries. There can be no assurance that our operating subsidiaries will generate sufficient net income to pay us dividends or sufficient cash flow to make payments of interest and principal to us. In addition, from time to time, our operating subsidiaries may enter into financing arrangements that contractually restrict or prohibit these types of upstream payments. There can also be adverse tax consequences associated with paying dividends.

Our financial and operating flexibility could be affected by our long-term debt and other financial commitments

As of December 31, 2012, we had long-term debt outstanding of approximately $4.4 billion. We also have various commitments for leases, firm transportation and processing, and purchase commitments. Our ability to service our debt and other obligations depends in large part upon the level of cash flows generated by our subsidiaries operations, possible dispositions of non-core assets, availability under our unsecured revolving credit facility and our ability to access the capital markets.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital

Our ability to access capital markets or to otherwise obtain sufficient financing is enhanced by our senior unsecured debt ratings as provided by the major credit rating agencies in the United States and our historical ability to access those markets as needed. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales, and near-term and long-term production growth opportunities. Liquidity, asset quality, cost structure, product mix, and commodity pricing levels and others are also considered by the rating agencies. A ratings downgrade could adversely impact our ability to access debt markets in the future, increase the cost of future debt, and potentially require us to post letters of credit for certain obligations.

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The loss of key executives or difficulty attracting and retaining experienced technical personnel could reduce our competitiveness and prospects for future success

The successful execution of the strategies central to our future success will depend, in part, on a few of our key executive officers. We have an employment agreement with our Chairman, President and Chief Executive Officer, Anthony G. Petrello, with a term through March 30, 2015, and other key personnel within the company. We do not carry significant amounts of key man insurance. Our operations depend, in part, on our ability to attract and retain experienced technical professionals. Competition for such professionals is intense. The loss of Mr. Petrello or other key executive officers, or our inability to attract or retain experienced technical personnel, could harm our ability to compete.

Noncompliance with governmental regulation or exposure to environmental liabilities could adversely affect our results of operations

Drilling of oil and gas wells is subject to various laws, rules and regulations in the various jurisdictions in where we operate. Our cost of compliance with these laws may be substantial. For example, the U.S. Environmental Protection Agency (EPA) has promulgated rules requiring the reporting of greenhouse gas emissions applicable to certain offshore oil and natural gas production and onshore oil and natural gas production, processing, transmission, storage and distribution facilities beginning in 2012 for emissions occurring in 2011. In addition, U.S. federal law imposes on responsible parties a variety of regulations related to the prevention of oil spills, release of hazardous substances, and liability for removal costs and natural resource, real or personal property and certain economic damages arising from such incidents. Some of these laws may impose strict and/or joint and several liability for these costs and damages without regard to the conduct of the parties. As an owner and operator of onshore and offshore rigs and other equipment, we may be deemed to be a responsible party under federal law. In addition, our completion and production services operations routinely involve the handling of significant amounts of materials, some of which are classified as solid or hazardous wastes or hazardous substances. We are subject to various laws governing the containment and disposal of hazardous substances, oilfield waste and other waste materials, the use of underground storage tanks and the use of underground injection wells. We employ personnel responsible for monitoring environmental compliance and arranging for remedial actions that may be required from time to time and also use consultants to advise on and assist with our environmental compliance efforts. Liabilities are recorded when the need for environmental assessments and/or remedial efforts become known or probable and the cost can be reasonably estimated.

The expansion of the scope of laws protecting the environment has accelerated in recent years, particularly outside the United States, and we expect this trend to continue. The violation of environmental laws can lead to the imposition of administrative, civil or criminal penalties, remedial obligations, and in some cases injunctive relief. Violations may also result in liabilities for personal injuries, property and natural resource damage and other costs and claims. We are not always successful in allocating all risks of these environmental liabilities to customers, and it is possible that customers who assume the risks will be financially unable to bear any resulting costs.

Changes in environmental laws related to hydraulic fracturing or other operations could result in increased costs of compliance and reductions or delays in drilling and completing new oil and natural gas wells, which could adversely impact the demand for fracturing and other services or our results of operations

Operations in our Completion Services operating segment include hydraulic fracturing, a process sometimes used in the completion of oil and gas wells whereby water, sand and chemicals are injected under pressure into subsurface formations to stimulate gas and, to a lesser extent, oil production. In 2011, the U.S. Department of Energy released a report on hydraulic fracturing, recommending the implementation of a variety of measures to reduce the environmental impacts from shale-gas production. The report could spur initiatives to regulate hydraulic fracturing under the Safe Drinking Water Act or under newly established legislation. Legislation has also been introduced in the U.S. Congress and adopted or introduced in some states requiring disclosure of chemicals used in the fracturing process. If enacted, the legislation could require fracturing activities to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping requirements and meet plugging and abandonment requirements. EPA has indicated an intent to regulate wastewater discharges under the Federal Clean Water Act from hydraulic fracturing and other natural gas production. In 2012, EPA also promulgated new rules establishing new air emission controls for oil and gas production and natural gas processing operations. These rules require, among other things, controlling emissions through flaring until 2015 and thereafter through reduced emissions completions, as well as imposing new requirements on emissions from tanks and other equipment. These rules and any other new laws regulating production and completion activities could cause operational delays, increased costs of compliance or increased costs in exploration and production, which could adversely affect our business and the demand for fracturing services.

Changes in environmental laws may also negatively impact the operations of oil and natural gas exploration and production companies, which in turn could have an adverse effect on us. For example, legislation has been proposed from time to time in the U.S. Congress that would reclassify some oil and natural gas production wastes as hazardous wastes under the Resources Conservation and Recovery Act, which would make the reclassified wastes subject to more stringent and costly handling, disposal and clean-up requirements. In addition, the Outer Continental Shelf Lands Act provides the federal government with broad discretion in regulating the leasing of offshore oil and gas production sites. Legislators and regulators in the United States and other jurisdictions where we operate also focus increasingly on restricting the emission of carbon dioxide, methane and other greenhouse gases that may contribute to warming of the Earth s atmosphere, and other climatic changes. The U.S. Congress has considered legislation designed to reduce emission of greenhouse gases, and some states in which we operate have passed legislation or adopted initiatives, such as the Regional Greenhouse Gas Initiative in the northeastern United States and the Western Regional Climate Action Initiative, which establish greenhouse gas inventories and/or cap-and-trade programs. Some international initiatives have also been adopted, which could result in increased costs of operations in covered jurisdictions. In addition, the EPA has published findings that emissions of greenhouse gases present an endangerment to public health and the environment, paving the way for further regulations that could restrict emissions of greenhouse gases under existing provisions of the Clean Air Act. Future or more stringent regulation could dramatically increase operating costs for oil and natural gas companies and could reduce the market for our services by making wells and/or oilfields uneconomical to operate.

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Significant exercises of stock options could adversely affect the market price of our common shares

As of February 25, 2013, we had 800,000,000 authorized common shares, of which 319,449,700 shares were outstanding. In addition, 37,726,170 common shares were reserved for issuance pursuant to stock option and employee benefit plans. The sale, or availability for sale, of substantial amounts of our common shares in the public market, whether directly by us or resulting from the exercise of options (and, where applicable, sales pursuant to Rule 144 under the Securities Act), would be dilutive to existing security holders, could adversely affect the prevailing market price of our common shares and could impair our ability to raise additional capital through the sale of equity securities.

Provisions in our organizational documents may deter a change-of-control transaction and decrease the likelihood of a shareholder receiving a change-of-control premium; conversely, those provisions may be insufficient to thwart an attempt to acquire control without paying a control premium

The Board of Directors has the authority to issue a significant number of common shares and up to 25,000,000 preferred shares, and to determine the price, rights (including voting rights), conversion ratios, preferences and privileges of the preferred shares, without any vote or action by shareholders. In 2012, the Board of Directors adopted a shareholder rights plan that limits the voting power a person can acquire without either securing the approval of the Board or having their voting interest diluted. The plan will expire in July 2013 unless it is extended. Although these provisions are designed to enhance the ability of the Board to negotiate with a potential acquiror to ensure that all shareholders receive fair value in exchange for control of the Company, they may also discourage potential acquirors and thus reduce the possibility of a takeover and therefore the likelihood that shareholders would receive a premium for their shares.

Conversely, we declassified our Board in 2012, which makes it easier for another party to acquire control of the Company. If the shareholder rights plan is not extended beyond July 2013, the ability of the Board to maximize value for all shareholders in a change-of-control transaction may be further diminished.

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We may have additional tax liabilities

We are subject to income taxes in the United States and numerous other jurisdictions. Significant judgment is required in determining our worldwide provision for income taxes. In the ordinary course of our business, there are many transactions and calculations where the ultimate tax determination is uncertain. We are regularly audited by tax authorities. Although we believe our tax estimates are reasonable, the final determination of tax audits and any related litigation could be materially different than what is reflected in income tax provisions and accruals. An audit or litigation could materially affect our financial position, income tax provision, net income, or cash flows in the period or periods challenged. It is also possible that future changes to tax laws (including tax treaties) could impact our ability to realize the tax savings recorded to date.

Proposed tax legislation could mitigate or eliminate the benefits of our 2002 reorganization as a Bermuda company

Various bills have been introduced in the U.S. Congress that could reduce or eliminate the tax benefits associated with our 2002 reorganization as a Bermuda company. There has been and we expect that there may continue to be legislation proposed by the U.S. Congress from time to time which, if enacted, could limit or eliminate the tax benefits associated with our reorganization. No assurance can be given that the tax benefits associated with our reorganization will continue to accrue to the benefit of the Company and its shareholders.

Legal proceedings could affect our financial condition and results of operations

We are subject to legal proceedings and governmental investigations from time to time that include employment, tort, intellectual property and other claims, and purported class action and shareholder derivative actions. We are also subject to complaints and allegations from former, current or prospective employees from time to time, alleging violations of employment-related laws. Lawsuits or claims could result in decisions against us that could have an adverse effect on our financial condition or results of operations.

The profitability of our operations could be adversely affected by turmoil in the global financial markets

The changes in general financial and political conditions, including the U.S. government budget, the downgrade by Standard & Poor s of the credit rating of U.S. government securities and concerns over the European sovereign debt crisis and banking industry has created a great deal of uncertainty in the recovery of the world economy. If global economic uncertainties continue over a prolonged period of time or develop adversely, there could be a material adverse impact on our credit ratings and liquidity and those of our customers and other worldwide business partners. If global oil and gas prices were to decline rapidly, it could lead our customers to curtail their operations or expansion and cause difficulties for us and our customers to forecast future capital expenditures, which in turn could negatively impact the worldwide rig count and our future financial results.

ITEM 1B. ***UNRESOLVED STAFF COMMENTS***

Not applicable.

ITEM 2. ***PROPERTIES***

Nabors principal executive offices are located in Hamilton, Bermuda. We own or lease executive and administrative office space in Dubai in the United Arab Emirates; Anchorage, Alaska; Calgary, Canada and Houston, Texas.

Many of the international drilling rigs and some of the Alaska rigs in our fleet are supported by mobile camps which house the drilling crews and a significant inventory of spare parts and supplies. In addition, we own various

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trucks, forklifts, cranes, earth-moving and other construction and transportation equipment, which are used to support our operations. We also own or lease a number of facilities and storage yards used in support of operations in each of our geographic markets.

We own certain mineral interests in connection with our investment in development and production of natural gas, oil and natural gas liquids in the United States and the Canadian provinces of Alberta and British Columbia.

The estimates of net proved oil and gas reserves as of December 31, 2012 were based on reserve reports prepared by independent petroleum engineers. AJM Deloitte prepared reports of estimated proved oil and gas reserves for our wholly owned assets in Canada. Cawley, Gillespie & Associates, Inc. prepared reports of estimated proved oil reserves for our wholly owned assets located in the Eagle Ford Shale, Texas. DeGolyer and MacNaughton Corp. prepared reports of estimated proved oil and gas reserves for our wholly owned assets in Alaska.

The estimates of net proved oil and gas reserves as of December 31, 2011 were based on reserve reports prepared by independent petroleum engineers. AJM Deloitte prepared reports of estimated proved oil and gas reserves for our wholly owned assets in Canada. Miller and Lents, Ltd. prepared reports of estimated proved oil and gas reserves for our wholly owned assets and interests in oil and natural gas properties located in the United States. Cawley, Gillespie & Associates, Inc. prepared reports of estimated proved oil reserves for our wholly owned assets located in the Eagle Ford Shale and Giddings field in Grimes County, Texas.

The estimates of net proved oil and gas reserves as of December 31, 2010 were based on reserve reports prepared by the following independent petroleum engineers. AJM Petroleum Consultants prepared reports of estimated proved oil and gas reserves for our wholly owned assets in Canada. Miller and Lents, Ltd. prepared reports of estimated proved oil and gas reserves for our wholly owned assets and interests in oil and natural gas properties located in the United States; Netherland, Sewell & Associates, Inc., prepared reports of estimated proved oil reserves for certain properties located in the Cat Canyon and West Cat Canyon fields in Santa Barbara County, California; and Lonquist & Co., LLC prepared reports of estimated proved oil and gas reserves for our wholly owned assets in Colombia.

Summary of Oil and Gas Reserves

The table below summarizes the proved reserves in each geographic area and by product type for our wholly owned subsidiaries and our proportionate interests in our equity companies during the applicable reporting period presented. We report proved reserves on the basis of the average of the first-day-of-the-month price for each month during the last 12-month period. Estimates of volumes of proved reserves of natural gas at year end are expressed in billions of cubic feet of natural gas (Bcf) at a pressure base of 14.73 pounds per square inch for natural gas and in millions of barrels (MMBbls) for oil and natural gas liquids.

For our wholly owned properties in the lower 48 states, the prices used in the reserve reports were $2.75 per thousand cubic feet of natural gas (Mcf) for the 12-month average of natural gas, $33.74 per barrel for natural gas liquids and $94.71 per barrel for oil at December 31, 2012. For our wholly owned properties in Alaska, the price used in our reserve report was $110.56 per barrel for oil at December 31, 2012. For our wholly owned properties in Canada, the price used in our reserve report was $1.05 per mcf for the 12-month average of natural gas at December 31, 2012.

No major discovery or other favorable or adverse event has occurred since December 31, 2012 that would cause a significant change in the estimated proved reserves as of that date.

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Reserve category	Reserves Liquids (MMBbls)	Natural Gas (Bcf)
As of December 31, 2012:		
Proved		
Developed		
Consolidated Subsidiaries		
United States	1.1	0.4
Canada		7.7
Colombia		
Total consolidated	1.1	8.1
Equity Company (1)		
United States		
Total equity company		
Total developed	1.1	8.1
Undeveloped		
Consolidated Subsidiaries		
United States	14.3	0.7
Canada		
Colombia		
Total consolidated	14.3	0.7
Equity Company (1)		
United States		
Total equity company		
Total undeveloped	14.3	0.7
Total proved	15.4	8.8

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Reserve category	Reserves Liquids (MMBbls)	Natural Gas (Bcf)
As of December 31, 2011:		
Proved		
Developed		
Consolidated Subsidiaries		
United States	0.9	13.6
Canada		8.2
Colombia		
Total consolidated	0.9	21.8
Equity Companies (1)		
United States	6.3	256.4
Canada		
Colombia		
Total equity companies	6.3	256.4
Total developed	7.2	278.2
Undeveloped		
Consolidated Subsidiaries		
United States	0.9	3.3
Canada		
Colombia		
Total consolidated	0.9	3.3
Equity Companies (1)		
United States	9.6	326.1
Canada		
Colombia		
Total equity companies	9.6	326.1
Total undeveloped	10.5	329.4
Total proved	17.7	607.6

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	Reserves	
Reserve category	Liquids (MMBbls)	Natural Gas (Bcf)
As of December 31, 2010:		
Proved		
Developed		
Consolidated Subsidiaries		
United States	2.7	17.1
Canada		5.5
Colombia	1.6	
Total consolidated	4.3	22.6
Equity Companies (1)		
United States	3.0	147.1
Canada		5.2
Colombia	0.5	
Total equity companies	3.5	152.3
Total developed	7.8	174.9
Undeveloped		
Consolidated Subsidiaries		
United States	18.5	2.7
Canada		
Colombia	0.4	
Total consolidated	18.9	2.7
Equity Companies (1)		
United States	4.9	405.7
Canada		
Colombia	1.4	
Total equity companies	6.3	405.7
Total undeveloped	25.2	408.4
Total proved	33.0	583.3

(1) Represents our proportionate interests in our equity companies for the applicable period.

The estimation of proved reserves, which is based on the requirement of reasonable certainty, is an ongoing process based on rigorous technical evaluations, commercial and market assessments and detailed analysis of well information such as flow rates and reservoir pressure declines. Furthermore, we record proved reserves only for projects that have received significant funding commitments by management made toward the development of the reserves. Although we are reasonably certain that proved reserves will be produced, the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and significant changes in projections of long-term oil and natural gas price levels.

Technologies Used in Establishing Proved Reserves Additions in 2012

Proved reserves were based on estimates generated through the integration of available and appropriate data, utilizing well established technologies that have been demonstrated in the field to yield repeatable and consistent results.

Data used in these integrated assessments included information obtained directly from the subsurface via wellbores, such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data utilized also included subsurface information obtained through indirect measurements including high-quality 2-D and 3-D seismic data, calibrated with available well control. Where applicable, surface geological information was also utilized. The tools used to interpret the data included proprietary seismic processing software, proprietary reservoir modeling and simulation software and commercially available data analysis packages.

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In some circumstances, where appropriate analog reservoirs were available, reservoir parameters from these analogs were used to increase the quality of and confidence in the reserves estimates.

Internal Controls over Proved Reserves

We maintain computerized records of our reserve estimates and production data. Appropriate controls, including limitations on access and updating capabilities, are in place to ensure data integrity. We engage qualified third-party reservoir engineers and perform reviews to ensure reserve estimations include all properties owned and are based on correct working and net revenue interests. Key components of the reserve estimation process include technical evaluations and analysis of well and field performance and a rigorous peer review. No changes may be made to reserve estimates unless these changes have been thoroughly reviewed and evaluated by authorized company personnel. After all changes are made, senior management reviews the estimates for final endorsement.

Proved Undeveloped Reserves

Our total estimated PUD reserves of approximately 86 billion cubic feet equivalent (Bcfe) as of December 31, 2012 decreased by 306 Bcfe from the 392 Bcfe of PUD reserves estimated at the end of 2011. During the year, we sold NFR Energy, which reported 384 Bcfe of PUD reserves at the end of 2011. Also during the year, we converted 72 Bcfe on the North Slope, Alaska. At December 31, 2012, our PUD reserves represented 85% of the 101 Bcfe reported in proved reserves.

During 2012, approximately $6.8 million was spent on projects associated with reserves that were carried as PUD reserves at the end of 2011. We completed development work that resulted in the transfer of approximately 0.6 Bcfe from proved undeveloped to proved developed reserves during 2012.

Oil and Gas Production, Production Prices and Production Costs

Oil and Gas Production

The table below summarizes production by final product sold, average production sales price and average production cost, each by geographic area for 2012 and 2011. Production costs are costs to operate and maintain our wells and related equipment and include the cost of labor, well-service and repair, location maintenance, power and fuel, transportation, cost of product, property taxes and production-related general and administrative costs.

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	United States		Canada		Colombia		Total	
	Liquids (MMBbls)	**Natural Gas (Bcf)**	**Liquids (MMBbls)**	**Natural Gas (Bcf)**	**Liquids (MMBbls)**	**Natural Gas (Bcf)**	**Liquids (MMBbls)**	**Natural Gas (Bcf)**
As of December 31, 2012:								
Oil and natural gas liquids production								
Consolidated subsidiaries	0.268	0.938		2.00	0.003		0.271	2.938
Equity companies (1)	0.545	19.01						
Average production sales prices:								
Consolidated subsidiaries	$ 76.74	$ 3.04	$	$ 2.36	$ 130.04	$	$ 77.33	$ 2.58
Equity companies (1)	$ 53.94	$ 2.70	$	$	$	$	$	$
Average production costs ($/bce):								
Consolidated subsidiaries		$ 3.52/Mcfe(2)		$ 2.91/Mcfe	$ 31.75/Boe			
Equity companies (1)		$ 1.47/Mcfe		$	$			
As of December 31, 2011:								
Oil and natural gas liquids production								
Consolidated subsidiaries	0.140	2.944		2.117	0.111	0.011	0.251	5.072
Equity companies (1)	0.409	18.634		0.380	0.316		0.725	19.014
Average production sales prices:								
Consolidated subsidiaries	$ 88.94	$ 4.09	$	$ 3.33	$ 111.57	$ 5.00	$ 98.91	$ 3.77
Equity companies (1)	$ 58.16	$ 4.03	$	$ 3.48	$ 84.47	$	$ 69.63	$ 4.02
Average production costs ($/bce):								
Consolidated subsidiaries		$ 3.35/Mcfe(2)		$ 12.96/Mcfe	$ 32.98/Boe(2)			
Equity companies (1)		$ 1.32/Mcfe		$ 11.99/Mcfe	$ 33.49/Boe			
As of December 31, 2010:								
Oil and natural gas liquids production								
Consolidated subsidiaries	0.073	3.533		3.058	0.230		0.303	6.591
Equity companies (1)	0.249	12.338		1.535	0.273		0.522	13.873
Average production sales prices:								
Consolidated subsidiaries	$ 63.77	$ 4.19	$	$ 3.69	$ 72.25	$	$ 70.19	$ 2.71
Equity companies (1)	$ 74.86	$ 4.43	$	$ 3.93	$ 73.90	$	$ 58.59	$ 4.11
Average production costs ($/bce):								
Consolidated subsidiaries		$ 2.14/Mcfe		$ 2.60/Mcfe	$ 34.42/Boe			
Equity companies (1)		$ 1.33/Mcfe		$ 5.89/Mcfe	$ 33.60/Boe			

(1) Represents our proportionate interests in our equity companies for the applicable period.

(2) Reflects the thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or natural gas liquids, or as Mcfe and reflects the barrel of oil equivalent or as Boe .

Drilling and Other Exploratory and Development Activities

During 2012, 2011 and 2010, our drilling program focused on proven and emerging oil and natural gas basins in the United States. Our drilling program included development activities with properties located in the United States, Canada and Colombia that are being actively marketed. The following tables provide the number of oil and gas wells completed during 2012, 2011 and 2010.

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Number of Net Productive and Exploratory Wells Drilled

	Net Productive Exploratory Wells Drilled	Net Dry Exploratory Wells Drilled
For the year ended December 31, 2012:		
Consolidated subsidiaries		
United States	2.40	
Canada		
Colombia	1.15	
Total consolidated	3.55	
Equity companies (1)		
United States	1.49	
Canada		
Colombia		
Total equity companies	1.49	
For the year ended December 31, 2011:		
Consolidated subsidiaries		
United States	5.14	3.63
Canada	3.00	4.00
Colombia		
Total consolidated	8.14	7.63
Equity companies (1)		
United States		
Canada		
Colombia		
Total equity companies		
For the year ended December 31, 2010:		
Consolidated subsidiaries		
United States	1.90	
Canada		
Colombia	4.20	
Total consolidated	6.10	
Equity companies (1)		
United States	0.90	
Canada		
Colombia	3.30	2.10
Total equity companies	4.20	2.10

(1) Represents our proportionate interests in our equity companies for the applicable period.

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	Net Productive Development Wells Drilled	Net Dry Development Wells Drilled
For the year ended December 31, 2012:		
Consolidated subsidiaries		
United States	6.50	
Canada		
Colombia		
Total consolidated	6.50	
Equity companies (1)		
United States	3.48	
Canada		
Colombia		
Total equity companies	3.48	
For the year ended December 31, 2011:		
Consolidated subsidiaries		
United States	2.04	3.28
Canada		
Colombia	2.00	1.40
Total consolidated	4.04	4.68
Equity companies (1)		
United States	10.45	
Canada		
Colombia		
Total equity companies	10.45	
For the year ended December 31, 2010:		
Consolidated subsidiaries		
United States	1.20	0.10
Canada		
Colombia		
Total consolidated	1.20	0.10
Equity companies (1)		
United States	9.50	
Canada		
Colombia	1.60	
Total equity companies	11.10	

(1) Represents our proportionate interests in our equity companies for the applicable period.

Present Activities

The following table provides the number of wells in the process of drilling as of December 31, 2012.

Wells Drilled

	United States		Canada		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Consolidated subsidiaries	4.00	1.53			4.00	1.53
Equity companies (1)						

(1) Represents our proportionate interests in our equity companies.

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Oil and Gas Properties, Wells, Operations and Acreage

Gross and Net Productive Wells

	For the year ended December 31, 2012	
	Gross	Net
Consolidated subsidiaries		
United States	63	28
Canada	7	7
Colombia		
Total consolidated	70	35
Equity companies (1)		
United States		
Canada		
Colombia		
Total equity companies		

(1) Represents our proportionate interests in our equity companies.

Gross and Net Developed Acreage

	United States		Canada		Total	
	Gross	Net	Gross	Net	Gross	Net
Consolidated subsidiaries	60,950	29,649	9,764	7,334	70,714	36,983
Equity companies (1)						

(1) Represents our proportionate interests in our equity companies.

Gross and Net Undeveloped Acreage

	United States		Canada		Total	
	Gross	Net	Gross	Net	Gross	Net
Consolidated subsidiaries	175,013	93,496	56,085	35,176	231,098	128,672
Equity companies (1)						

(1) Represents our proportionate interests in our equity companies.

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Lease Expirations of Net Acreage

	United States			Canada		
	2013	**2014**	**2015**	**2013**	**2014**	**2015**
Consolidated subsidiaries (1)	4,754	14,836	17,966	12,244		417
Equity companies (2)						

(1) The carrying value of leases at December 31, 2012 was approximately $114 million.

(2) No equity companies existed at December 31, 2012.

While our drilling program includes development activities with properties that are being actively marketed, we plan to continue the terms of some of these licenses and concession areas through operational or administrative actions. We believe the amount of undeveloped acreage that will be abandoned or allowed to expire at the end of the lease term is immaterial to our operations.

Additional information about our properties can be found in Notes 2 Summary of Significant Accounting Policies, 18 Commitments and Contingencies (under the caption Leases) and our Schedule of Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited) in Part II, Item 8. Financial Statements and Supplementary Data. The revenues and property, plant and equipment by geographic area for 2012, 2011 and 2010 can be found in Note 22 Segment Information in Part I, Item 8. Financial Statements and Supplementary Data. A description of our rig fleet is included under the caption Introduction in Part I, Item 1. Business.

Management believes that our existing equipment and facilities are adequate to support our current level of operations as well as an expansion of drilling operations in those geographical areas where we may expand.

ITEM 3. *LEGAL PROCEEDINGS*

Nabors and its subsidiaries are defendants or otherwise involved in a number of lawsuits in the ordinary course of business. We estimate the range of our liability related to pending litigation when we believe the amount and range of loss can be estimated. We record our best estimate of a loss when the loss is considered probable. When a liability is probable and there is a range of estimated loss with no best estimate in the range, we record the minimum estimated liability related to the lawsuits or claims. As additional information becomes available, we assess the potential liability related to our pending litigation and claims and revise our estimates. Due to uncertainties related to the resolution of lawsuits and claims, the ultimate outcome may differ from our estimates. For matters where an unfavorable outcome is reasonably possible and significant, we disclose the nature of the matter and a range of potential exposure, unless an estimate cannot be made at the time of disclosure. In the opinion of management and based on liability accruals provided, our ultimate exposure with respect to these pending lawsuits and claims is not expected to have a material adverse effect on our consolidated financial position or cash flows, although they could have a material adverse effect on our results of operations for a particular reporting period.

On July 5, 2007, we received an inquiry from the U.S. Department of Justice relating to its investigation of one of our vendors and compliance with the Foreign Corrupt Practices Act. The inquiry related to transactions with and involving Panalpina, which provided freight forwarding and customs clearance services to some of our affiliates. The inquiry focused on transactions in Kazakhstan, Saudi Arabia, Algeria and Nigeria. The Audit Committee of our Board of Directors engaged outside counsel to review some of our transactions with this vendor, received periodic updates at its regularly scheduled meetings, and the Chairman of the Audit Committee received updates between meetings as circumstances warranted. The investigation included a review of certain amounts paid to and by Panalpina in connection with obtaining permits for the temporary importation of equipment and clearance of goods and materials through customs. Both the SEC and the Department of Justice have been advised of our investigation. In April 2012, the SEC advised us that it concluded its review of this matter and did not intend to recommend any enforcement action against us. In February 2013, the Department of Justice likewise advised us that it concluded its inquiry, also without recommending any enforcement action against us.

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In 2009, the Court of Ouargla (in Algeria) entered a judgment of approximately $19.7 million against us related to alleged customs infractions in 2009. We believe we did not receive proper notice of the judicial proceedings, and that the amount of the judgment is excessive in any case. We asserted the lack of legally required notice as a basis for challenging the judgment on appeal to the Algeria Supreme Court. In May 2012, that court reversed the lower court and remanded the case to the Ouargla Court of Appeals for treatment consistent with the Supreme Court s ruling. In January 2013, the Ouargla Court of Appeals reinstated the judgment. We have again lodged an appeal to the Algeria Supreme Court, asserting the same challenges as before. Based upon our understanding of applicable law and precedent, we continue to believe that we will prevail. We do not believe that a loss is probable and have not accrued any amounts related to this matter. If we are ultimately required to pay a fine or judgment related to this matter, the amount of the loss could range from approximately $140,000 to $19.7 million.

In March 2011, the Court of Ouargla entered a judgment of approximately $39.1 million against us relating to alleged violations of Algeria s foreign currency exchange controls, which require that goods and services provided locally be invoiced and paid in local currency. The case relates to certain foreign currency payments made to us by CEPSA, a Spanish operator, for wells drilled in 2006. Approximately $7.5 million of the total contract amount was paid offshore in foreign currency, and approximately $3.2 million was paid in local currency. The judgment includes fines and penalties of approximately four times the amount at issue, and is not payable pending appeal. We have appealed the ruling based on our understanding that the law in question applies only to resident entities incorporated under Algerian law. An intermediate court of appeals has upheld the lower court s ruling, and we have appealed the matter to the Algeria Supreme Court. While our payments were consistent with our historical operations in the country, and, we believe, those of other multinational corporations there, as well as interpretations of the law by the Central Bank of Algeria, the ultimate resolution of this matter could result in a loss of up to $31.1 million in excess of amounts accrued.

On September 21, 2011, we received an informal inquiry from the SEC related to perquisites and personal benefits received by the officers and directors of Nabors, including their use of non-commercial aircraft. Our Audit Committee and Board of Directors have been apprised of this inquiry and we are cooperating with the SEC. The ultimate outcome of this process cannot be determined at this time.

On March 9, 2012, Nabors Global Holdings II Limited (NGH2L) signed a contract with ERG Resources, LLC (ERG) relating to the sale of all of the Class A shares of NGH2L s wholly owned subsidiary, Ramshorn International Limited, an oil and gas exploration company. When ERG failed to meet its closing obligations, NGH2L terminated the transaction on March 19, 2012 and, as contemplated in the agreement, retained ERG s $3 million escrow deposit. ERG filed suit the following day in the 61st Judicial District Court of Harris County, Texas, in a case styled *ERG Resources, LLC v. Nabors Global Holdings II Limited, Ramshorn International Limited,* and *Parex Resources, Inc.;* Cause No. 2012-16446, seeking injunctive relief to halt any sale of the shares to a third party, specifically naming as defendant Parex Resources, Inc. (Parex). The lawsuit also seeks monetary damages of up to $100 million based on an alleged breach of contract by NGH2L and alleged tortious interference with contractual relations by Parex. Nabors successfully defeated ERG s effort to obtain a temporary restraining order from the Texas court on March 20, 2012. On March 23, 2012, ERG filed and obtained an *ex parte* stay from the Supreme Court of Bermuda (Commercial Court), in a case styled as *ERG Resources LLC v. Nabors Global Holdings II Limited,* Case No. 2012: No. 110. Nabors challenged the stay and, following a series of oral hearings on the matter, the Bermuda court discharged the stay by a ruling dated April 5, 2012. Nabors completed the sale of Ramshorn s Class A shares to a Parex affiliate on April 12, 2012, which mooted ERG s application for a temporary injunction that was scheduled for hearing by the Texas court on April 13, 2012. ERG retains its causes of action for monetary damages, but Nabors believes the claims are foreclosed by the terms of the agreement and are without factual or legal merit. Although we are vigorously defending the lawsuit, its ultimate outcome cannot be determined at this time.

ITEM 4. ***MINE SAFETY DISCLOSURES***

Not applicable.

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PART II

ITEM 5. *MARKET FOR REGISTRANT S COMMON EQUITY, RELATED SHAREHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES*

STOCK PERFORMANCE GRAPH

The following graph illustrates comparisons of five-year cumulative total returns among Nabors, the S&P 500 Index and the Dow Jones Oil Equipment and Services Index. Total return assumes $100 invested on December 31, 2007 in shares of Nabors, the S&P 500 Index, and the Dow Jones Oil Equipment and Services Index. It also assumes reinvestment of dividends and is calculated at the end of each calendar year, December 31, 2008 - 2012.

	2008	2009	2010	2011	2012
Nabors Industries Ltd.	**44**	**80**	**86**	**63**	**53**
S&P 500 Index	63	80	92	94	109
Dow Jones Oil Equipment and Services Index	41	67	86	75	75

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Market and Share Prices

Our common shares are traded on the New York Stock Exchange under the symbol NBR . At February 25, 2013, there were approximately 1,525 shareholders of record.

The following table sets forth the reported high and low sales prices of our common shares as reported on the New York Stock Exchange for the periods indicated.

Calendar Year		Share Price High	Share Price Low
2011	First quarter	30.70	21.50
	Second quarter	32.47	22.43
	Third quarter	27.63	12.26
	Fourth quarter	20.69	11.05
2012	First quarter	22.73	16.36
	Second quarter	17.84	12.40
	Third quarter	16.83	12.77
	Fourth quarter	15.50	12.75

The following table provides information relating to Nabors repurchase of common shares during the three months ended December 31, 2012:

Period (In thousands, except per share amounts)	Total Number of Shares Purchased (1)	Average Price Paid per Share (1)	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Program (2)
October 1 October 31	2	$ 14.01		
November 1 November 30	1	$ 13.71		
December 1 December 31	2	$ 14.67		

(1) Shares were withheld from employees and directors to satisfy certain tax withholding obligations due in connection with grants of stock under our 2003 Employee Stock Plan and option exercises from our 1996 Employee Stock Plan. The 2003 Employee Stock Plan, 1998 Employee Stock Plan, 1999 Stock Option Plan for Non-employee Directors and 1996 Employee Stock Plan provide for the withholding of shares to satisfy tax obligations, but do not specify a maximum number of shares that can be withheld for this purpose. These shares were not purchased as part of a publicly announced program to purchase common shares.

(2) We do not intend to make further purchases of our common shares under a share repurchase program that was authorized by the Board of Directors in July 2006.

See Part III, Item 12. for a description of securities authorized for issuance under equity compensation plans.

Dividend Policy

We have not paid any cash dividends on our common shares since 1982. On February 22, 2013, our Board of Directors declared a cash dividend of $0.04 per share to the holders of our common shares as of March 11, 2013 to be paid on March 28, 2013. The Board s current intention is to pay cash dividends on a quarterly basis in the future. However, the amounts and timing of future dividends are subject to approval by the Board and will depend on future business conditions, financial conditions, results of operations and other factors.

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Shareholder Matters

Bermuda has exchange controls which apply to residents in respect of the Bermuda dollar. As an exempted company, Nabors is considered to be nonresident for such controls; consequently, there are no Bermuda governmental restrictions on our ability to make transfers and carry out transactions in all other currencies, including currency of the United States.

There is no reciprocal tax treaty between Bermuda and the United States regarding withholding taxes. Under existing Bermuda law there is no Bermuda income or withholding tax on dividends paid by Nabors to its shareholders. Furthermore, no Bermuda tax is levied on the sale or transfer (including by gift and/or on the death of the shareholder) of Nabors common shares (other than by shareholders resident in Bermuda).

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ITEM 6. ***SELECTED FINANCIAL DATA***

Operating Data (1)(2)

[redacted]					
Revenues and other income:					
[redacted]					
Earnings (losses) from unconsolidated affiliates	(301,320)	56,647	33,267	(155,432)	(192,548)
[redacted]					
Total revenues and other income	6,751,390	6,136,938	4,175,013	3,532,310	5,223,060
[redacted]					
Costs and other deductions:					
[redacted]					
General and administrative expenses	532,568	489,892	338,720	421,492	473,885
[redacted]					
Interest expense	251,552	256,633	272,712	266,047	196,726
[redacted]					
Impairments and other charges	290,260	198,072	61,292	118,543	145,447
[redacted]					
Income (loss) from continuing operations before income taxes	274,683	487,769	293,570	68,784	719,447
[redacted]					
Subsidiary preferred stock dividend	3,000	3,000	750		
[redacted]					
Income (loss) from discontinued operations, net of tax	(74,400)	(97,440)	(161,090)	(218,609)	(39,597)
[redacted]					
Less: Net (income) loss attributable to noncontrolling interest	(621)	(1,045)	(85)	342	(3,927)
[redacted]					
Earnings (losses) per share:					
[redacted]					
Basic from discontinued operations	(0.25)	(0.34)	(0.57)	(0.77)	(0.14)
[redacted]					
[redacted]					
Diluted from discontinued operations	(0.26)	(0.34)	(0.55)	(0.76)	(0.14)
[redacted]					
Weighted-average number of common shares outstanding:					
[redacted]					
Diluted	292,323	292,484	289,996	286,502	288,236
[redacted]					
Capital expenditures and acquisitions of businesses (3)	$ 1,433,586	$ 2,247,735	$ 1,878,063	$ 990,287	$ 1,578,241
[redacted]					

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Balance Sheet Data (1)(2)

	Year Ended December 31, 2012	2011	2010	2009	2008
	(In thousands, except per share amounts and ratio data)				
Cash, cash equivalents and short-term investments	$ 778,204	$ 539,489	$ 801,190	$ 1,090,851	$ 586,111
Working capital	2,000,475	1,285,752	458,550	1,568,042	1,037,734
Property, plant and equipment, net	8,712,088	8,629,946	7,815,419	7,646,050	7,331,959
Total assets	12,656,022	12,912,140	11,646,569	10,644,690	10,517,899
Long-term debt	4,379,336	4,348,490	3,064,126	3,940,605	3,600,533
Shareholders equity	5,944,929	5,587,815	5,328,162	5,167,656	4,904,106
Debt to capital ratio:					
Gross (5)	0.42:1	0.45:1	0.45:1	0.43:1	0.44:1
Net (6)	0.38:1	0.42:1	0.41:1	0.36:1	0.40:1

(1) All periods present the operating activities of our wholly owned oil and gas businesses in the United States, Canada and Colombia, our equity interests in joint ventures in Canada and Colombia and our aircraft logistics operations in Canada as discontinued operations.

(2) Our acquisitions results of operations and financial position have been included beginning on the respective dates of acquisition and include Peak (July 2011), Stone Mountain Venture Partnership (SMVP) (June 2011), Energy Contractors (December 2010) and NCPS (formerly Superior) (September 2010).

(3) Represents capital expenditures and the total purchase price of acquisitions.

(4) The interest coverage ratio is a trailing 12-month quotient of the sum of (x) operating revenues and earnings (losses) from unconsolidated affiliates, direct costs and general administrative expenses *less* our proportionate share of full-cost ceiling test writedowns recorded by our unconsolidated oil and gas joint ventures (in years applicable) *divided* by (y) interest expense. The interest coverage ratio is not a measure of operating performance or liquidity defined by accounting principles generally accepted in the United States of America (GAAP) and may not be comparable to similarly titled measures presented by other companies.

(5) The gross debt to capital ratio is calculated by dividing (x) total debt by (y) total capital. Total capital is defined as total debt *plus* shareholders equity. The gross debt to capital ratio is not a measure of operating performance or liquidity defined by GAAP and may not be comparable to similarly titled measures presented by other companies.

(6) The net debt to capital ratio is calculated by dividing (x) net debt by (y) net capital. Net debt is total debt *minus* the sum of cash and cash equivalents and short-term investments. Net capital is the sum of net debt *plus* shareholders equity. The net debt to capital ratio is not a measure of operating performance or liquidity defined by GAAP and may not be comparable to similarly titled measures presented by other companies.

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

Management Overview

This section is intended to help you understand our results of operations and our financial condition. This information is provided as a supplement to, and should be read in conjunction with, our consolidated financial statements and the accompanying notes thereto.

We have grown from a land drilling business centered in the U.S. Lower 48 states, Canada and Alaska to an international business with operations on land and offshore in most of the major oil and gas markets in the world. Our worldwide fleet of actively marketed rigs consists of 474 land drilling rigs, 548 rigs for land well-servicing and workover work in the United States and Canada, offshore platform rigs, jackup units, barge rigs and a large component of trucks and fluid hauling vehicles. We have investments in oil and gas exploration, development and production activities in the United States and Canada, but are marketing to dispose of our oil and gas portfolio in an expeditious and prudent manner.

The majority of our business is conducted through two business lines:

- Our Drilling & Rig Services business line includes our drilling operations for oil and natural gas wells, on land and offshore, and companies engaged in drilling technology, top drive manufacturing, directional drilling, construction services, and rig instrumentation and software. This business line, consisting of six operating segments, includes U.S. Lower 48 Land Drilling, U.S. Offshore, Alaska, Canada, and International operations. Our U.S. Lower 48 Land Drilling and International operating segments also represent reportable segments based on quantitative thresholds. In addition, our Other Rig Services operating segment combines Canrig Drilling Technology Ltd., Peak Oilfield Services and Ryan Directional Services, Inc. The latter operating segment does not meet the criteria for disclosure, individually or in the aggregate, as a reportable segment.

- Our Completion & Production Services business line includes our well-servicing, fluid logistics, workover operations and our pressure pumping services. This business line, consisting of two operating segments, includes U.S. Production Services and Completion Services, and represents reportable segments.

Our businesses depend, to a large degree, on the level of spending by oil and gas companies for exploration, development and production activities. A sustained increase or decrease in the price of oil or natural gas could materially impact exploration, development and production activities, and consequently, our financial position, results of operations and cash flows.

The magnitude of customer spending on new and existing wells is the primary driver of our business. Our customers spending is determined principally by their internally generated cash flow and to a lesser extent by joint venture arrangements and funding from the capital markets. In our Drilling & Rig Services business line, operations have traditionally been driven by natural gas prices, but the majority of current activity is driven by the price of oil and natural gas liquids from unconventional reservoirs (shales). In our Completion & Production Services business line, operations are primarily driven by oil prices.

During 2012, domestic ongoing weak natural gas prices, combined with a general decline in natural gas liquids and a mid-year sharp, but temporary, drop in crude oil prices, resulted in a second-half contraction in customer spending. This led to a curtailment of drilling-related expenditures by many companies and an oversupply of rigs in the markets where we operate. We believe gas and liquids prices are likely to remain weak through 2013. Crude oil pricing has been more resilient, but remains volatile and potentially vulnerable, which keeps our customers forward-spending plans in check for the near-term. Projections of stable crude oil pricing at today s level and improving liquids pricing later in the year, if realized, should lead to increased domestic drilling activity later in 2013. Nonetheless, it is also likely that continuing additions of new rig capacity and improving rig efficiency will result in a continued oversupply of rigs for most, if not all, of the year.

Our international markets have been much slower to respond to the improving oil prices of the last two years and continue to be dampened by cost issues in several markets which should abate as the year progresses. This abatement, combined with a general tightening of the rig supply-demand balance, leading to improving rates, and the deployment of several large projects and other rigs returning to work should improve international results in 2013.

The following table sets forth oil and natural gas price data per Bloomberg for the last three years:

[redacted]						
Commodity prices:						
[redacted]						
Average Henry Hub natural gas spot price ($/thousand cubic feet (mcf))	$ 2.75	$ 4.00	$ 4.37	$ (1.25)	(31)%	$ (0.37)	(8)%
[redacted]						

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Operating revenues and Earnings (losses) from unconsolidated affiliates in 2012 totaled $6.7 billion, representing an increase of $571.3 million, or 9%, over 2011. Adjusted income derived from operating activities in 2012 totaled $918.6 million, representing an increase of 6% compared to 2011, while net income (loss) from continuing operations in 2012 totaled $239.1 million ($0.82 per diluted share), representing a decrease of 30% compared to 2011.

Operating revenues and Earnings (losses) from unconsolidated affiliates for 2011 totaled $6.1 billion, representing an increase of $1.9 billion, or 47%, over 2010. Adjusted income derived from operating activities and net income (loss) from continuing operations for 2011 totaled $867.4 million and $342.2 million ($1.17 per diluted share), respectively, representing increases of 34% over 2010 for both financial measures.

During 2012, our income (loss) from continuing operations was negatively impacted by impairments and other charges, including full-cost ceiling test writedowns from NFR Energy totalling $310.0 million, representing our proportionate share of the writedowns, a $75.0 million impairment of an intangible asset related to the Superior trade name, a provision for the retirement of long-lived assets totaling $138.7 million in multiple operating segments, a $50.4 million impairment of some coil-tubing rigs and a goodwill impairment totaling $26.3 million. Partially offsetting these charges were $160 million of asset gains, primarily relating to selling our interest in NFR Energy at the end of 2012. Excluding these items, our operating results improved as a result of increased demand for our services and products due to increased drilling activity in oil- and liquids-rich shale plays and increased well-servicing activity in the U.S. and Canada. This increase in activity has more than offset the drop in demand from gas-related plays.

During 2011, operating results improved as compared to 2010 primarily due to the incremental revenue and positive operating results from the addition of our Completion Services operating segment beginning in September 2010, increased drilling activity in oil- and liquids-rich shale plays in our drilling operations in both our U.S. Lower 48 Land and Canada Drilling business units and increased well-servicing activity in the U.S. and Canada. However, our operating results and activity levels were negatively impacted in our U.S. Offshore operations in response to uncertainty in the regulatory environment in the Gulf of Mexico, our Alaskan operations due to key customers spending constraints, and in Saudi Arabia due to downtime and reduced rates on several jackup rigs.

Our income from continuing operations during 2011 was negatively impacted by $198.1 million in impairments and other charges, $100 million of which related to a provision for a contingent liability that existed on December 31, 2011 for a potential termination payment to our former Chief Executive Officer, which was not paid. See Note 3 for further discussion. The remaining $98.1 million was comprised of a provision for retirement of long-lived assets recorded by multiple operating segments. This related to the decommissioning and retirement of assets previously utilized in our U.S. Lower 48 Land Drilling, International and U.S. Production Services operations and the amounts are reflected in the Impairments and other charges line in our consolidated statements of income (loss).

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The following tables set forth certain information with respect to our reportable segments and rig activity:

	Year Ended December 31,			Increase/(Decrease)			
	2012	2011	2010	2012 to 2011		2011 to 2010	
	(In thousands, except percentages and rig activity)						
Reportable segments:							
Operating revenues and Earnings (losses) from unconsolidated affiliates from continuing operations: (1)							
Drilling & Rig Services:							
U.S. Lower 48 Land Drilling	$ 1,860,357	$ 1,698,620	$ 1,294,853	$ 161,737	10%	$ 403,767	31%
U.S. Offshore	268,986	170,727	123,761	98,259	58%	46,966	38%
Alaska	147,465	129,894	179,218	17,571	14%	(49,324)	(28)%
Canada	572,616	574,754	389,229	(2,138)		185,525	48%
International	1,265,060	1,104,461	1,093,608	160,599	15%	10,853	1%
Other Rig Services (2)	839,533	674,206	427,154	165,327	25%	247,052	58%
Subtotal Drilling & Rig Services (3)	4,954,017	4,352,662	3,507,823	601,355	14%	844,839	24%
Completion & Production Services:							
U.S. Production Services	857,668	701,223	444,665	156,445	22%	256,558	58%
Completion Services	1,462,767	1,237,306	321,295	225,461	18%	916,011	285%
Subtotal Completion & Production Services (4)	2,320,435	1,938,529	765,960	381,906	20%	1,172,569	153%
Other reconciling items (5)(7)	(586,199)	(174,193)	(106,033)	(412,006)	(237)%	(68,160)	(64)%
Total	$ 6,688,253	$ 6,116,998	$ 4,167,750	$ 571,255	9%	$ 1,949,248	47%

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	Year Ended December 31,			Increase/(Decrease)			
	2012	2011	2010	2012 to 2011		2011 to 2010	
	(In thousands, except percentages and rig activity)						
Adjusted income (loss) derived from operating activities from continuing operations: (1) (6)							
Drilling & Rig Services:							
U.S. Lower 48 Land Drilling	$ 467,716	$ 414,317	$ 274,215	$ 53,399	13%	$ 140,102	51%
U.S. Offshore	(305)	843	9,245	(1,148)	(136)%	(8,402)	(91)%
Alaska	42,483	27,671	51,896	14,812	54%	(24,225)	(47)%
Canada	96,536	94,637	22,970	1,899	2%	71,667	312%
International	91,226	123,813	254,744	(32,587)	(26)%	(130,931)	(51)%
Other Rig Services (2)	79,061	55,617	42,401	23,444	42%	13,216	31%
Subtotal Drilling & Rig Services (3)	776,717	716,898	655,471	59,819	8%	61,427	9%
Completion & Production Services:							
U.S. Production Services	103,659	74,725	31,597	28,934	39%	43,128	136%
Completion Services	188,518	229,125	66,651	(40,607)	(18)%	162,474	244%
Subtotal Completion & Production Services (4)	292,177	303,850	98,248	(11,673)	(4)%	205,602	209%
Other reconciling items (7)	(150,245)	(153,385)	(104,827)	3,140	2%	(48,558)	(46)%
Total adjusted income (loss) derived from operating activities	$ 918,649	$ 867,363	$ 648,892	$ 51,286	6%	$ 218,471	34%
U.S. oil and gas joint venture earnings (losses)	(301,801)	59,685	18,657	(361,486)	(606)%	41,028	220%
Interest expense	(251,552)	(256,633)	(272,712)	5,081	2%	16,079	6%
Investment income (loss)	63,137	19,940	7,263	43,197	217%	12,677	175%
Gains (losses) on sales and disposals of long-lived assets and other income (expense), net	136,510	(4,514)	(47,238)	141,024	n/m(8)	42,724	90%
Impairments and other charges	(290,260)	(198,072)	(61,292)	(92,188)	(47)%	(136,780)	(223)%
Income (loss) from continuing operations before income taxes	274,683	487,769	293,570	(213,086)	(44)%	194,199	66%
Income tax expense (benefit)	32,628	142,605	36,950	(109,977)	(77)%	105,655	286%
Subsidiary preferred stock dividend	3,000	3,000	750			2,250	300%
Income (loss) from continuing operations, net of tax	239,055	342,164	255,870	(103,109)	(30)%	86,294	34%
Income (loss) from discontinued operations, net of tax	(74,400)	(97,440)	(161,090)	23,040	24%	63,650	40%
Net income (loss)	164,655	244,724	94,780	(80,069)	(33)%	149,944	158%
Less: Net (income) loss attributable to noncontrolling interest	(621)	(1,045)	(85)	424	41%	(960)	n/m(8)
Net income (loss) attributable to Nabors	$ 164,034	$ 243,679	$ 94,695	$ (79,645)	(33)%	$ 148,984	157%
Rig activity:							
Rig years: (9)							
U.S. Lower 48 Land Drilling	200.7	200.2	174.5	0.5		25.7	15%
U.S. Offshore	12.8	9.6	9.4	3.2	33%	0.2	2%
Alaska	5.6	4.9	7.4	0.7	14%	(2.5)	(34)%
Canada	34.8	39.8	29.8	(5.0)	(13)%	10.0	34%

International (10)	119.3	105.3	97.8	14.0	13%	7.5	8%
Total rig years	373.2	359.8	318.9	13.4	4%	40.9	13%
Rig hours: (11)							
U.S. Production Services	853,373	791,956	643,813	61,417	8%	148,143	23%
Canada Production Services	181,185	184,908	172,589	(3,723)	(2)%	12,319	7%
Total rig hours	1,034,558	976,864	816,402	57,694	6%	160,462	20%

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(1) All periods present the operating activities of our wholly owned oil and gas businesses in the United States, Canada and Colombia, our equity interests in joint ventures in Canada and Colombia and our aircraft logistics operations in Canada as discontinued operations.

(2) Includes our drilling technology and top drive manufacturing, directional drilling, rig instrumentation and software, and construction services. These services represent our other companies that are not aggregated into a reportable operating segment.

(3) Includes earnings (losses), net from unconsolidated affiliates, accounted for using the equity method, of $(3.1) million and $14.6 million for the years ended December 31, 2011 and 2010, respectively.

(4) Includes earnings (losses), net from unconsolidated affiliates, accounted for using the equity method, of $.5 million for the year ended December 31, 2012.

(5) Represents the elimination of inter-segment transactions and earnings (losses), net from the U.S. unconsolidated oil and gas joint venture, accounted for using the equity method until sold in December 2012, of $(301.8) million, $59.7 million and $18.7 million for the years ended December 31, 2012, 2011 and 2010, respectively.

(6) Adjusted income (loss) derived from operating activities is computed by subtracting the sum of direct costs, general and administrative expenses, depreciation and amortization and earnings (losses) from the U.S. oil and gas joint venture from the sum of Operating revenues and Earnings (losses) from unconsolidated affiliates. These amounts should not be used as a substitute for the amounts reported in accordance with GAAP. However, management evaluates the performance of our business units and the consolidated company based on several criteria, including adjusted income (loss) derived from operating activities, because it believes that these financial measures accurately reflect our ongoing profitability. A reconciliation of this non-GAAP measure to income (loss) from continuing operations before income taxes, which is a GAAP measure, is provided in the above table.

(7) Represents the elimination of inter-segment transactions and unallocated corporate expenses.

(8) Number is so large that it is meaningless.

(9) Excludes well-servicing rigs, which are measured in rig hours. Includes our equivalent percentage ownership of rigs owned by unconsolidated affiliates. Rig years represent a measure of the number of equivalent rigs operating during a given period. For example, one rig operating 182.5 days during a 365-day period represents 0.5 rig years.

(10) International rig years includes our equivalent percentage ownership of rigs owned by unconsolidated affiliates, which totaled 2.5 years, 2.1 years and 2.2 years in years 2012, 2011 and 2010, respectively.

(11) Rig hours represents the number of hours that our well-servicing rig fleet operated during the year.

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Segment Results of Operations

Drilling & Rig Services

Our Drilling & Rig Services business line includes drilling on land and offshore, drilling technology, top drive manufacturing, directional drilling, construction services and rig instrumentation and software.

U.S. Lower 48 Land Drilling. The results of operations for this segment were as follows:

	Year Ended December 31, 2012	2011	2010	Increase/(Decrease) 2012 to 2011		2011 to 2010	
	(In thousands, except percentages and rig activity)						
Operating revenues	$ 1,860,357	$ 1,698,620	$ 1,294,853	$ 161,737	10%	$ 403,767	31%
Adjusted income derived from operating activities	$ 467,716	$ 414,317	$ 274,215	$ 53,399	13%	$ 140,102	51%
Rig years	200.7	200.2	174.5	0.5		25.7	15%

Operating results increased from 2011 to 2012 primarily due to higher average dayrates and a slight increase in drilling activity, as well as $39.6 million in revenues recognized that were related to early contract terminations. These increases were partially offset by higher depreciation expense related to new rigs placed into service during 2012.

Operating results increased from 2010 to 2011 primarily due to higher average dayrates and increases in drilling activity, driven by deployment of rigs into oil- and liquids-rich shale areas. The increase was partially offset by higher operating costs associated with increased drilling activity, as well as higher depreciation expense related to new rigs placed into service since January 2010.

U.S. Offshore. The results of operations for this segment were as follows:

	Year Ended December 31, 2012	2011	2010	Increase/(Decrease) 2012 to 2011		2011 to 2010	
	(In thousands, except percentages and rig activity)						
Operating revenues	$ 268,986	$ 170,727	$ 123,761	$ 98,259	58%	$ 46,966	38%
Adjusted income derived from operating activities	$ (305)	$ 843	$ 9,245	$ (1,148)	(136)%	$ (8,402)	(91)%
Rig years	12.8	9.6	9.4	3.2	33%	0.2	2%

Operating revenues increased from 2011 to 2012 resulting primarily from higher utilization for the SuperSundownerTM platform rigs and the MODS® rigs. The increase was partially offset by declining activities for the Sundowner® platform rigs in our shallow water areas. Adjusted income derived from operating activities decreased from 2011 to 2012 primarily due to the Sundowner® platform rigs discussed above and profit reduction on a construction project.

Operating revenues increased from 2010 to 2011 as a result of higher workover activities by the Sundowner® platform and jackup rigs and from profits related to a major construction project. Adjusted income derived from operating activities decreased from 2010 to 2011 primarily due to lower utilization for the MODS® rigs and SuperSundownerTM platform rigs. Drilling permits have been subject to a lengthy and stringent safety and environmental review process since the Gulf of Mexico blowout in mid-2010.

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Alaska. The results of operations for this segment were as follows:

	Year Ended December 31,			Increase/(Decrease)			
	2012	2011	2010	2012 to 2011		2011 to 2010	
	(In thousands, except percentages and rig activity)						
Operating revenues	$ 147,465	$ 129,894	$ 179,218	$ 17,571	14%	$ (49,324)	(28)%
Adjusted income derived from operating activities	$ 42,483	$ 27,671	$ 51,896	$ 14,812	54%	$ (24,225)	(47)%
Rig years	5.6	4.9	7.4	0.7	14%	(2.5)	(34)%

The increases in operating results from 2011 to 2012 were due to higher average dayrates and increased drilling activity, driven primarily by an overall increase in winter exploration activity in the first and second quarters of 2012, as well as increased camp activity and margins.

The decreases in operating results from 2010 to 2011 were primarily due to lower average dayrates and drilling activity. While drilling activity levels decreased significantly during 2010, operating results decreased only slightly due to the acceleration of recognized deferred revenues from a significant contract that terminated.

Canada. The results of operations for this segment were as follows:

	Year Ended December 31,			Increase/(Decrease)			
	2012	2011	2010	2012 to 2011		2011 to 2010	
	(In thousands, except percentages and rig activity)						
Operating revenues	$ 572,616	$ 574,754	$ 389,229	$ (2,138)		$ 185,525	48%
Adjusted income derived from operating activities	$ 96,536	$ 94,637	$ 22,970	$ 1,899	2%	$ 71,667	312%
Rig years	34.8	39.8	29.8	(5.0)	(13)%	10.0	34%
Rig hours	181,185	184,908	172,589	(3,723)	(2)%	12,319	7%

Operating revenues decreased slightly from 2011 to 2012 primarily as a result of decreases in drilling and well-servicing activity, partially offset by increased drilling dayrates. Adjusted income derived from operating activities increased from 2011 to 2012 due to these higher dayrates, which offset the decreases in drilling and well-servicing activities. The current natural gas oversupply in North America, and resulting low natural gas prices, decreased customer demand for gas drilling and well-servicing activity in 2012. Reduced natural gas drilling activity was largely offset by increased demand in oil exploration in 2012. Strong oil prices caused growth in oil drilling activity and increased drilling dayrates, with more demand for larger rigs required to drill long-reach horizontal wells in the shale plays and the oil sands. Direct costs and general and adminstrative expenses for 2012 were in-line with 2011 costs.

Operating results increased from 2010 to 2011 primarily as a result of increases in drilling and well-servicing activity and drilling dayrates and well-servicing hourly rates. The increased drilling and well-servicing activity in Western Canada is the result of renewed interest in oil exploration, supported by strong oil commodity prices. Operating results were negatively impacted by higher drilling costs for well-servicing in 2011 for preparing service rigs for high utilization and additional labor costs for crew travel, retention and training.

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International. The results of operations for this segment were as follows:

	Year Ended December 31,			Increase/(Decrease)			
	2012	2011	2010	2012 to 2011		2011 to 2010	
	(In thousands, except percentages and rig activity)						
Operating revenues and Earnings (losses) from unconsolidated affiliates	$ 1,265,060	$ 1,104,461	$ 1,093,608	$ 160,599	15%	$ 10,853	1%
Adjusted income derived from operating activities	$ 91,226	$ 123,813	$ 254,744	$ (32,587)	(26)%	$ (130,931)	(51)%
Rig years	119.3	105.3	97.8	14.0	13%	7.5	8%

Operating revenues and Earnings from unconsolidated affiliates increased from 2011 to 2012 and from 2010 to 2011 as a result of increases in the utilization of our overall rig fleet albeit at lower margins. Adjusted income derived from operating activities decreased from 2011 to 2012 primarily from the decreases in average dayrates and lower utilization of our jackup rigs in Saudi Arabia and lower offshore activity in Congo. These decreases were partially offset by new activity in Papua, New Guinea and increased utilization of rigs in Mexico.

Adjusted income derived from operating activities decreased from 2010 to 2011 primarily from the decreases in average dayrates and lower utilization of our jackup rigs in Saudi Arabia and other drilling activities in Qatar and Australia.

Other Rig Services. The results of operations for this segment were as follows:

	Year Ended December 31,			Increase/(Decrease)			
	2012	2011	2010	2012 to 2011		2011 to 2010	
	(In thousands, except percentages)						
Operating revenues and Earnings (losses) from unconsolidated affiliates	$ 839,533	$ 674,206	$ 427,154	$ 165,327	25%	$ 247,052	58%
Adjusted income derived from operating activities	$ 79,061	$ 55,617	$ 42,401	$ 23,444	42%	$ 13,216	31%

The increase in operating results from 2011 to 2012 and from 2010 to 2011 primarily resulted from higher demand in the United States and Canada drilling markets for top drives, rig instrumentation and data collection services from oil and gas exploration companies and higher third-party rental and rigwatch units, which generate higher margins, partially offset by a continued decline in customer demand for our construction services in Alaska.

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Completion & Production Services

Our Completion & Production Services business line includes well-servicing, fluid logistics, workover operations and pressure pumping services**.**

U.S. Production Services. The results of operations for this segment were as follows:

	Year Ended December 31,			Increase/(Decrease)			
	2012	2011	2010	2012 to 2011		2011 to 2010	
	(In thousands, except percentages and rig activity)						
Operating revenues Earnings (losses) from unconsolidated affiliates	$ 857,668	$ 701,223	$ 444,665	$ 156,445	22%	$ 256,558	58%
Adjusted income derived from operating activities	$ 103,659	$ 74,725	$ 31,597	$ 28,934	39%	$ 43,128	136%
Rig hours	853,373	791,956	643,813	61,417	8%	148,143	23%

Operating results increased from 2011 to 2012 and from 2010 to 2011 primarily due to increases in rig and truck utilization facilitated by capital invested to increase rig and truck fleets as well as frac tank counts. Equipment utilization and price improvements experienced in 2012 and 2011 were primarily driven by sustained higher oil prices.

Completion Services. The results of operations for this segment were as follows:

	Year Ended December 31,			Increase/(Decrease)			
	2012	2011	2010	2012 to 2011		2011 to 2010	
	(In thousands, except percentages)						
Operating revenues	$ 1,462,767	$ 1,237,306	$ 321,295	$ 225,461	18%	$ 916,011	285%
Adjusted income derived from operating activities	$ 188,518	$ 229,125	$ 66,651	$ (40,607)	(18)%	$ 162,474	244%

Operating revenues increased from 2011 to 2012 primarily due to the increased levels of fracturing activity and associated increase in our assets deployed in the major producing areas in the United States. Adjusted income derived from operating activities decreased due to lower margins on product sales as a result of higher commodity prices.

Operating results during 2010 reflect the impact of our acquisition of Superior in September 2010. See Note 5 Acquisitions in Part II, Item 8. Financial Statements and Supplementary Data.

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Assets Held for Sale

Assets Held for Sale	December 31, 2012		2011
	(In thousands)		
Oil and Gas	$	377,625	$ 385,414
Other Rig Services		6,232	16,086
	$	383,857	$ 401,500

Oil and Gas

During 2010, we began marketing our oil and gas assets in Canada and Colombia, including our then 49.7% and 50.0% ownership interests in Remora and SMVP, respectively, and we reclassified the assets to assets held for sale. In 2011, we reclassified the carrying value of our wholly owned U.S. oil and gas assets to assets held for sale. The carrying value of our assets held for sale as of December 31, 2012 and 2011, represents the lower of carrying value or fair value less costs to sell. We continue to market these properties at prices that are reasonable compared to current fair value. Also, at December 31, 2012, we have deferred tax assets of approximately $106 million, which are included in long-term deferred income taxes in our consolidated balance sheet, associated with our oil and gas operations in Canada.

We have contracts with pipeline companies to pay specified fees based on committed volumes for gas transport and processing. At December 31, 2012, our undiscounted contractual commitments for such contracts approximate $339.6 million. At December 31, 2012, we have liabilities of $206 million, $69 million of which are classified as current and are included in accrued liabilities. These amounts represent our best estimate of the fair value of the excess capacity of the pipeline commitments calculated using a discounted cash flow model (a Level 3 measurement), when considering our disposal plan, current production levels, natural gas prices and expected utilization of the pipeline over the remaining contractual term. Decreases in actual production or natural gas prices could result in future charges related to excess capacity of the pipeline.

During 2011, we evaluated production levels, natural gas prices and market conditions, and determined our production flowing to pipelines and processing plants did not meet the volumes required under the contracts. Accordingly at December 31, 2011, we recorded liabilities of $125 million, $71 million was classified as current and included in accrued liabilities.

In 2011, we sold some of our wholly owned oil and gas assets in Colombia to an unrelated party. We received proceeds of $89.2 million from this sale and recognized a gain of approximately $39.6 million. Additionally during 2011, Remora completed sales of its oil and gas assets and made cash distributions to us in the amount of $143.0 million. At December 31, 2012 and 2011, our oil and gas assets held for sale included a receivable of approximately $4.1 million and $13.7 million, respectively, representing a final distribution to us upon dissolution of this joint venture.

In 2011, we sold our 25% working interest in the Cat Canyon and West Cat Canyon fields in Santa Barbara County, California to an unrelated party and received proceeds of approximately $71.6 million. Also, the equity owners of SMVP dissolved the partnership and a proportionate share of the assets and liabilities were conveyed to us in exchange for our ownership interest.

In 2012, we sold our remaining wholly owned oil and gas business in Colombia and sold some of our U.S. wholly owned oil and gas assets in the Fayetteville Shale, Floyd Shale, and Barnett Shale areas as well as properties primarily in Texas, Louisiana and Utah. We received cumulative cash receipts of $104.5 million from these third parties during 2012.

Other Rig Services

During 2011, we determined that one of our Canadian subsidiaries that provides logistics services for onshore drilling using helicopter and fixed-wing aircraft met the accounting criteria of assets held for sale. Based on quoted market prices, the carrying value of these assets at December 31, 2012 and 2011 represent fair value less costs to sell.

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Discontinued Operations

The operating results from the assets discussed above for all periods presented are retroactively presented and accounted for as discontinued operations in the accompanying audited consolidated statements of income (loss). Our condensed statements of income (loss) from discontinued operations for each operating segment were as follows:

Operating revenues and Earnings from unconsolidated affiliates												
Oil and Gas	$	27,363	$	125,654(1)	$	37,615	$	(98,291)	(78)%	$	88,039	234%
Other Rig Services	$	25,813	$	29,713	$	29,739	$	(3,900)	(13)%	$	(26)	
Income (loss) from discontinued operations												
Oil and Gas	$	(66,033)(2)	$	(91,394)(3)	$	(156,290)(4)	$	25,361	28%	$	64,896	42%
Other Rig Services	$	(8,367)(5)	$	(6,046)(5)	$	(4,800)	$	(2,321)	(38)%	$	(1,246)	(26)%

Oil and Gas

(1) Includes approximately $83 million of equity in earnings during 2011 for our proportionate share of Remora s net income, inclusive of the gains recognized for asset sales during 2011.

(2) Includes adjustments during 2012 to increase our pipeline contractual commitments by $128.1 million and other gains and losses related to the sale of our wholly owned oil and gas-centered assets.

(3) Includes impairments during 2011 of $255.0 million to write down the carrying value of our wholly owned oil and gas-centered assets, including $27.2 million related to an oil and gas financing receivable that was deemed uncollectible.

(4) Includes impairments during 2010 of $192.2 million related to our wholly owned oil and gas assets. Of this total, $137.8 million represented writedowns to the carrying value of some acreage in the United States, which we did not have future plans to develop due to sustained low natural gas prices, and certain exploratory wells in Colombia, which we determined were uneconomical to develop in the foreseeable future. The remaining $54.3 million related to impairment of an oil and gas financing receivable and was determined using discounted cash flow models, a Level 3 measurement, and involved assumptions based on estimated cash flows for proved and probable reserves, undeveloped acreage value, and current and expected natural gas prices.

Other Rig Services

(5) Includes $7.8 million and $7.9 million, respectively, of impairment (a Level 3 measurement) in 2012 and 2011 to our aircraft and logistics assets as a result of the continued downturn in the oil and gas industry in Canada.

Additional discussion of our policy pertaining to the calculations of our annual impairment tests, including any impairment of goodwill, is set forth in Critical Accounting Estimates below in this section and in Note 2 Summary of Significant Accounting Policies in Part II, Item 8. Financial Statements and Supplementary Data. Additional information relating to discontinued operations is provided in Notes 4 Discontinued Operations and our Schedule of Supplemental Information on Oil and Gas Exploration and Production Activities in Part II, Item 8. Financial Statements and Supplementary Data. A further protraction of lower commodity prices or an inability to sell these assets in a timely manner could result in recognition of future impairment charges.

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OTHER FINANCIAL INFORMATION

General and administrative expenses

	Year Ended December 31,			Increase/(Decrease)			
	2012	2011	2010	2012 to 2011		2011 to 2010	
	(In thousands, except percentages)						
General and administrative expenses	$ 532,568	$ 489,892	$ 338,720	$ 42,676	9%	$ 151,172	45%
General and administrative expenses as a percentage of operating revenues	7.6%	8.1%	8.2%	(0.5)%	(6)%	(0.1)%	(1)%

General and administrative expenses increased from 2011 to 2012 and from 2010 to 2011 primarily as a result of increases in wages to support a higher headcount as a result of increased operations for a majority of our operating segments and our Superior acquisition in September 2010 in the case of the 2010 to 2011 period. As a percentage of operating revenues, general and administrative expenses decreased from 2011 to 2012 and from 2010 to 2011.

Depreciation and amortization

	Year Ended December 31,			Increase/(Decrease)			
	2012	2011	2010	2012 to 2011		2011 to 2010	
	(In thousands, except percentages)						
Depreciation and amortization	$ 1,055,517	$ 924,094	$ 760,962	$ 131,423	14%	$ 163,132	21%

Depreciation and amortization expense increased from 2011 to 2012 and from 2010 to 2011 as a result of the incremental depreciation expense from (i) additional completion and production services assets, (ii) newly constructed rigs recently placed into service and (iii) rig upgrades and other capital expenditures made during 2011 and 2012.

Interest expense

	Year Ended December 31,			Increase/(Decrease)			
	2012	2011	2010	2012 to 2011		2011 to 2010	
	(In thousands, except percentages)						
Interest expense	$ 251,552	$ 256,633	$ 272,712	$ (5,081)	(2)%	$ (16,079)	(6)%

Interest expense decreased from 2011 to 2012 primarily as a result of the redemption in May 2011 of our remaining 0.94% senior exchangeable notes, aggregate principal amount $1.4 billion, and the redemption in August 2012 of our 5.375% senior notes, aggregate principal amount $275 million. The decrease was partially offset by interest expense increases related to our August 2011 issuance of 4.625% senior notes due September 2021 and interest on larger amounts outstanding on our revolving credit facilities.

Interest expense decreased from 2010 to 2011 as a result of repurchases during 2010 and the redemption in May 2011 for a total of $2.6 billion in par value of the 0.94% senior exchangeable notes over 2010 and 2011. The decrease was partially offset by additional interest related to our August 2011 issuance of 4.625% senior notes due September 2021, a full year of interest on our September 2010 issuance of 5.0% senior notes due September 2020 and interest on amounts outstanding on our revolving credit facilities.

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Investment income (loss)

	Year Ended December 31, 2012	2011	2010	Increase/(Decrease) 2012 to 2011		2011 to 2010	
	(In thousands, except percentages)						
Investment income (loss)	$ 63,137	$ 19,940	$ 7,263	$ 43,197	217%	$ 12,677	175%

Investment income during 2012 was $63.1 million and included (i) $41.1 million net realized gains from our trading securities, (ii) $14.5 million realized gains from short-term and other long-term investments and (iii) $7.5 million interest and dividend income from our cash, other short-term and long-term investments.

Investment income during 2011 was $19.9 million and included (i) a $12.9 million realized gain relating to one of our overseas fund investments classified as long-term investments, (ii) $5.1 million realized gains from short-term and other long-term investments and (iii) $9.9 million interest and dividend income from our cash, other short-term and long-term investments. Investment income was partially offset by net unrealized losses of $8.0 million from our trading securities.

Investment income during 2010 was $7.3 million and included interest and dividend income of $7.5 million from our cash, other short-term and long-term investments and $4.2 million from gains on sales of short-term and long-term investments, partially offset by net unrealized losses of $4.4 million from our trading securities.

Gains (losses) on sales and disposals of long-lived assets and other income (expense), net

	Year Ended December 31, 2012	2011	2010	Increase/(Decrease) 2012 to 2011		2011 to 2010	
	(In thousands, except percentages)						
Gains (losses) on sales and disposals of long-lived assets and other income (expense), net	$ 136,510	$ (4,514)	$ (47,238)	$ 141,024	n/m(1)	$ 42,724	90%

n/m (1) The number is so large that is meaningless.

The amount of gains (losses) on sales and disposals of long-lived assets and other income (expense), net for 2012 was a net gain of $136.5 million, which included net gains on sales and disposals of long-lived assets of approximately $147.5 million, primarily as result of the gain from the sale of our equity interest in NFR Energy. These gains were partially offset by (i) increases to our litigation reserves of $5.4 million and (ii) foreign currency exchange losses of approximately $4.8 million.

The amount of gains (losses) on sales and disposals of long-lived assets and other income (expense), net for 2011 was a net loss of $4.5 million and was comprised of (i) increases to our litigation reserves of $11.3 million, (ii) foreign currency exchange losses of approximately $5.5 million and (iii) a net loss on sales and disposals of long-lived assets of approximately $1.9 million. The net loss was partially offset by a $13.1 million gain recognized in connection with our acquisition of the remaining 50 percent equity interest of Peak.

The amount of gains (losses) on sales and disposals of long-lived assets and other income (expense), net for 2010 represented a net loss of $47.2 million and included: (i) foreign currency exchange losses of approximately $18.1 million, (ii) litigation expenses of $6.4 million, (iii) net losses on sales and disposals of long-lived assets of approximately $6.4 million, (iv) acquisition-related costs of $7.0 million and (v) losses of $7.0 million recognized on purchases of our 0.94% senior exchangeable notes due 2011.

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Impairments and Other Charges

	Year Ended December 31,			Increase/(Decrease)			
	2012	2011	2010	2012 to 2011		2011 to 2010	
	(In thousands, except percentages)						
Provision for retirement of long-lived assets	$ 138,666	$ 98,072	$ 23,213	$ 40,594	41%	$ 74,859	322%
Intangible asset impairment	74,960			74,960	100%		
Goodwill impairments	26,279		10,707	26,279	100%	(10,707)	(100)%
Impairment of long-lived assets	50,355		27,372	50,355	100%	(27,372)	(100)%
Provision for termination payment		100,000		(100,000)	(100)%	100,000	100%
Total impairments and other charges	$ 290,260	$ 198,072	$ 61,292	$ 92,188		$ 136,780	

Provision for retirement of long-lived assets

During 2012, we recorded a provision for retirement of long-lived assets in multiple operating segments, including $34.0 million in U.S. Lower 48 Land Drilling, $3.1 million in U.S. Offshore, $33.7 million in Canada, $16.5 million in International and $2.0 million in Other Rig Services, all from our Drilling & Rig Services business line. The retirements in this business line included mechanical rigs, a jackup rig and other assets that have become inoperable or functionally obsolete and that we do not believe could be returned to service without significant costs to refurbish.

Additionally in 2012, we recorded similar provisions for retirement of long-lived assets of $49.4 million in our Nabors Completion & Production Services business line. During 2012, we streamlined our operations and consolidated our U.S. Production Services and Completion Services into this business line, and retired some non-core assets. As we continue to streamline our lines of business, there could be future retirement or impairment charges, which could have a potential impact on our future operating results.

During 2011, we recorded a provision for retirement of long-lived assets totaling $98.1 million in multiple operating segments. This related to the decommissioning and retirement of one jackup rig, 116 land rigs, and a number of rigs and trucks. Our U.S. Lower 48 Land Drilling, International and U.S. Production Services operations recorded $63.2 million, $26.1 million and $8.9 million, respectively. These assets were deemed to be functionally or economically non-competitive for today s market and are being dismantled for parts and scrap.

During 2010, we recorded a provision for retirement of long-lived assets totaling $23.2 million related to the abandonment of certain rig components, comprised of engines, top-drive units, building modules and other equipment that had become obsolete or inoperable in our U.S. Lower 48 Land Drilling, U.S. Production Services and U.S. Offshore Drilling & Rig Services business line.

A prolonged period of lower oil and natural gas prices and its potential impact on our utilization and dayrates could result in the recognition of future impairment charges to additional assets if future cash flow estimates, based upon information then available to management, indicate that the carrying value of those assets may not be recoverable.

Intangible asset impairment

During 2012, we recorded impairment of the Superior trade name totaling $75.0 million. The Superior trade name was initially classified as a ten-year intangible asset at the date of acquisition in September 2010. The impairment is a result of the decision to cease using the Superior trade name to reduce confusion in the marketplace and enhance the Nabors brand.

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Goodwill impairments

During 2012, we impaired the remaining goodwill balances of $7.3 million and $19.0 million of our U.S. Offshore and International operating segments, respectively. The impairments were deemed necessary due to the prolonged uncertainty of utilization of some of our rigs in the Gulf of Mexico as well as our international markets. We did not record any goodwill impairment in 2011.

During 2010, we recognized an impairment of approximately $10.7 million relating to our goodwill balance of our U.S. Offshore operating segment. The impairment charge was deemed necessary due to the uncertainty of utilization of some of our rigs as a result of changes in our customers plans for future drilling operations in the Gulf of Mexico. Many of our customers suspended drilling operations in the Gulf of Mexico, largely as a result of their inability to obtain government permits. Although the U.S. deepwater drilling moratorium was lifted, our customers continued to encounter delays in obtaining government permits.

These impairment charges stemmed from our annual impairment test on goodwill, A significantly prolonged period of lower oil and natural gas prices or changes in laws and regulations could adversely affect the demand for and prices of our services, which could result in future goodwill impairment charges for other reporting units due to the potential impact on our estimate of our future operating results. See Critical Accounting Policies below and Note 2 Summary of Significant Accounting Policies (included under the caption Goodwill) in Part II, Item 8. Financial Statements and Supplementary Data.

Impairments of long-lived assets

During the fourth quarter of 2012, we determined that some of our coil-tubing rigs would not be fully utilized as forecasted, which resulted in a triggering event and required a year-end long-lived asset impairment test. Our year-end impairment test resulted in impairment charges of $17.4 million in our U.S. Lower 48 Land Drilling and $32.9 million in our Canada operations. We did not record any impairment of long-lived assets in 2011.

During 2010, we recognized $27.3 million in impairment charges related to some jackup rigs in our U.S. Offshore operating segment. These impairment charges stemmed from our annual impairment tests on long-lived assets.

Provision for termination payment

During the fourth quarter of 2011, we recorded a provision for a contingent liability that existed on December 31, 2011 related to the change of our Chief Executive Officer that occurred in October 2011. This charge resulted from a potential termination payment to our former Chief Executive Officer, Eugene Isenberg, under the terms of his employment contract. Subsequent to December 31, 2011, Mr. Isenberg elected to forego triggering that payment, and as a result, we did not owe or make the termination payment. During 2012, we made charitable contributions to benefit the needs of our employees and other community-based causes. We contributed one million Nabors common shares previously held by an affiliate to the Nabors Charitable Foundation, a 501(c)(3) organization, in support of this objective. The election of Mr. Isenberg to forego triggering the potential payment, offset by the charitable contributions described above, was recorded as a capital contribution during the first quarter of 2012.

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Income tax rate

	Year Ended December 31,			Increase/(Decrease)			
	2012	2011	2010	2012 to 2011		2011 to 2010	
Effective income tax rate from continuing operations	12%	29%	13%	(17)%	(59)%	16%	123%

The changes in our effective tax rate from 2011 to 2012 and from 2010 to 2011 resulted mainly from the proportion of income generated in the United States versus other countries where we operate. Income generated in the United States is generally taxed at a higher rate than other jurisdictions.

We are subject to income taxes in the United States and numerous other jurisdictions. Significant judgment is required in determining our worldwide provision for income taxes. One of the most volatile factors in this determination is the relative proportion of our income or loss being recognized in high- versus low-tax jurisdictions. In the ordinary course of our business, there are many transactions and calculations for which the ultimate tax determination is uncertain. We are regularly audited by tax authorities. Although we believe our tax estimates are reasonable, the final outcome of tax audits and any related litigation could be materially different than what is reflected in our income tax provisions and accruals. The results of an audit or litigation could materially affect our financial position, income tax provision, net income, or cash flows.

Various bills have been introduced in Congress that could reduce or eliminate the tax benefits associated with our 2002 reorganization as a Bermuda company. Legislation enacted by the U.S. Congress in 2004 provides that a corporation reorganizing in a foreign jurisdiction on or after March 4, 2003 be treated as a domestic corporation for U.S. federal income tax purposes. There has been and we expect that there may continue to be legislation proposed by Congress from time to time which, if enacted, could limit or eliminate the tax benefits associated with our reorganization.

Because we cannot predict whether legislation will ultimately be adopted, no assurance can be given that the tax benefits associated with our reorganization will ultimately accrue to the benefit of the Company and its shareholders. It is possible that future changes to the tax laws (including tax treaties) could impact our ability to realize the tax savings recorded to date as well as future tax savings resulting from our reorganization.

Liquidity and Capital Resources

Cash Flows

Our cash flows depend, to a large degree, on the level of spending by oil and gas companies for exploration, development and production activities. Sustained increases or decreases in the price of oil or natural gas could have a material impact on these activities, and could also materially affect our cash flows. Certain sources and uses of cash, such as the level of discretionary capital expenditures or acquisitions, purchases and sales of investments, issuances and repurchases of debt and of our common shares are within our control and are adjusted as necessary based on market conditions. We discuss our 2012 and 2011 cash flows below.

*Operating Activities***.** Net cash provided by operating activities totaled $1.6 billion during 2012 compared to net cash provided by operating activities of $1.5 billion during 2011. Net cash provided by operating activities (operating cash flows) is our primary source of capital and liquidity. Factors affecting changes in operating cash flows are largely the same as those that impact net earnings, with the exception of non-cash expenses such as depreciation and amortization, depletion, impairments, share-based compensation, deferred income taxes and our proportionate share of earnings or losses from unconsolidated affiliates. Net income (loss) adjusted for non-cash components was approximately $1.6 billion and $1.5 billion in 2012 and 2011, respectively. Additionally, changes in working capital items such as collection of receivables can be a significant component of operating cash flows. Changes in working capital items used $61.1 million and $36.7 million, respectively, in cash flows during 2012 and 2011.

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*Investing Activities***.** Net cash used for investing activities totaled $1.2 billion during 2012 compared to net cash used for investing activities of $1.9 billion in 2011. Our primary use of cash for investing activities is for capital expenditures related to rig-related enhancements, new construction and equipment, as well as sustaining capital expenditures. During 2012 and 2011, we used cash for capital expenditures totaling $1.5 billion and $2.0 billion, respectively.

In 2012, cash of $254.5 million was provided in proceeds from sales of our oil and gas assets and equity interests in unconsolidated oil and gas joint ventures.

During 2011, cash of $160.8 million was provided in proceeds from sales of our wholly owned oil and gas assets and equity interests in unconsolidated oil and gas joint ventures. During 2011, we provided cash of $112.3 million to our unconsolidated affiliates. Additionally during 2011, we received distributions of $143.0 million from Remora related to proceeds it received from the sale of its oil and gas assets in Colombia.

*Financing Activities***.** Net cash used for financing activities totaled $254 million during 2012, including repayment of $282.4 million, representing principal and accrued interest, of our $275 million 5.375% senior notes. $30 million, net, of the required cash came from our revolving credit facilities.

Net cash provided by financing activities was $163.2 million during 2011. During 2011, we drew $1.6 billion from our revolving credit facilities primarily for the redemption of the remaining $1.4 billion of our 0.94% senior exchangeable notes. During 2011, cash was provided from the receipt of $690.4 million in proceeds, net of debt issuance costs, from the issuance by Nabors Delaware of its 4.625% senior notes due September 2021 in August 2011 and was used to repay amounts then outstanding under the revolving credit facilities.

Future Cash Requirements

We expect capital expenditures over the next 12 months to approximate $1.0 - 1.2 billion. We had outstanding purchase commitments of approximately $0.4 billion at December 31, 2012, primarily for rig-related enhancements, new construction and equipment, as well as sustaining capital expenditures, other operating expenses and purchases of inventory. This amount could change significantly based on market conditions and new business opportunities. The level of our outstanding purchase commitments and our expected level of capital expenditures over the next 12 months represent a number of capital programs that are currently underway or planned. These programs will result in an expansion in the number of land drilling and offshore rigs, pressure pumping and well-servicing equipment that we own and operate. We can reduce the planned expenditures if necessary, or increase them if market conditions and new business opportunities warrant it.

We have historically completed a number of acquisitions and will continue to evaluate opportunities to acquire assets or businesses to enhance our operations. Several of our previous acquisitions were funded through issuances of debt or our common shares. Future acquisitions may be paid for using existing cash or by issuing debt or additional shares of our stock. Such capital expenditures and acquisitions will depend on our view of market conditions and other factors.

See our discussion of guarantees issued by Nabors that could have a potential impact on our financial position, results of operations or cash flows in future periods included below under Off-Balance Sheet Arrangements (Including Guarantees).

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The following table summarizes our contractual cash obligations as of December 31, 2012:

	Total	< 1 Year	Payments due by Period 1-3 Years (In thousands)	3-5 Years	Thereafter
Contractual cash obligations:					
Long-term debt: (1)					
Principal	$ 4,390,000	$	$	$ 890,000(2)	$ 3,500,000(3)
Interest	1,577,744	231,432	462,911	462,826	420,575
Operating leases (4)	67,076	25,609	23,647	8,293	9,527
Purchase commitments (5)	422,048	377,021	45,027		
Employment contracts (4)	9,006	5,830	3,176		
Pension funding obligations	599	599			
Transportation and processing contracts (4)(6)	339,586	67,251	176,617	46,368	49,350

The table above excludes liabilities for unrecognized tax benefits totaling $126.8 million as of December 31, 2012 because we are unable to make reasonably reliable estimates of the timing of cash settlements with the respective taxing authorities. Further details on the unrecognized tax benefits can be found in Note 13 Income Taxes in Part II, Item 8. Financial Statements and Supplementary Data.

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(1) See Note 12 Debt in Part II, Item 8. Financial Statements and Supplementary Data.

(2) Represents amounts drawn on a revolving credit facility, which expires November 2017.

(3) Represents Nabors Delaware s aggregate 6.15% senior notes due February 2018, 9.25% senior notes due January 2019, 5.0% senior notes due September 2020 and 4.625% senior notes due September 2021.

(4) See Note 18 Commitments and Contingencies in Part II, Item 8. Financial Statements and Supplementary Data.

(5) Purchase commitments include agreements to purchase goods or services that are enforceable and legally binding and that specify all significant terms, including fixed or minimum quantities to be purchased; fixed, minimum or variable pricing provisions; and the approximate timing of the transaction.

(6) We have contracts with pipeline companies to pay specified fees based on committed volumes for gas transport and processing, as calculated on a monthly basis. See Notes, 4 Assets Held for Sale and Discontinued Operations and 18 Commitments and Contingencies in Part II, Item 8. Financial Statements and Supplementary Data.

We may from time to time seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for equity securities, both in open-market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

See Note 18 Commitments and Contingencies in Part II, Item 8. Financial Statements and Supplementary Data for discussion of commitments and contingencies relating to (i) our employment agreement with Mr. Petrello that could result in a cash payment of $50 million by the Company if his employment were terminated in the event of death or disability or a cash payment of approximately $40.8 million if his employment were terminated without cause or in the event of a change in control and (ii) off-balance sheet arrangements (including guarantees).

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Financial Condition and Sources of Liquidity

Our primary sources of liquidity are cash and investments, availability under our revolving credit facility, and cash generated from operations. As of December 31, 2012, we had cash and short-term investments of $778.2 million and working capital of $2.0 billion. We also had $610 million of availability remaining from our $1.5 billion revolving credit facility. As of December 31, 2011, we had cash and short-term investments of $539.5 million and working capital of $1.3 billion. We also had $540 million of availability remaining from a combined total of $1.4 billion under revolving credit facilities.

In 2012, we sold our remaining wholly owned oil and gas business in Colombia and sold additional wholly owned assets in the United States. In December 2012, we sold our 49.7% ownership interest in NFR Energy. During 2012, we received cumulative gross cash proceeds of $254.5 million from sales of oil and gas assets.

We had nine letter-of-credit facilities with various banks as of December 31, 2012. Availability under these facilities as of December 31, 2012 was as follows:

		(In thousands)
Credit available	$	358,649
Letters of credit outstanding, inclusive of financial and performance guarantees		57,303
Remaining availability	$	301,346

Our ability to access capital markets or to otherwise obtain sufficient financing is enhanced by our senior unsecured debt ratings as provided by the major credit rating agencies in the United States and our historical ability to access those markets as needed. While there can be no assurances that we will be able to access these markets in the future, we believe that we will be able to access capital markets or otherwise obtain financing in order to satisfy any payment obligation that might arise upon exchange or purchase of our notes and that any cash payment due, in addition to our other cash obligations, would not ultimately have a material adverse impact on our liquidity or financial position. A ratings downgrade could adversely impact our ability to access debt markets in the future, increase the cost of future debt, and potentially require us to post letters of credit for certain obligations.

Our gross debt to capital ratio was 0.42:1 as of December 31, 2012 and 0.45:1 as of December 31, 2011. Our net debt to capital ratio was 0.38:1 as of December 31, 2012 and 0.42:1 as of December 31, 2011.

The gross debt to capital ratio is calculated by dividing (x) total debt by (y) total capital. Total capital is defined as total debt *plus* shareholders equity.

The net debt to capital ratio is calculated by dividing (x) net debt by (y) net capital. Net debt is total debt *minus* the sum of cash and cash equivalents and short-term investments. Net capital is the sum of net debt *plus* shareholders equity. Both of these ratios are used to calculate a company s leverage in relation to its capital. Neither ratio measures operating performance or liquidity as defined by GAAP and, therefore, may not be comparable to similarly titled measures presented by other companies.

Our interest coverage ratio was 7.9:1 as of December 31, 2012 and 7.2:1 as of December 31, 2011. The interest coverage ratio is a trailing 12-month quotient of the sum of (x) operating revenues and earnings (losses) from unconsolidated affiliates, direct costs and general administrative expenses *less* our proportionate share of full-cost ceiling test writedowns recorded by our unconsolidated oil and gas joint ventures *divided* by (y) interest expense. This ratio is a method for calculating the amount of operating cash flows available to cover cash interest expense. The interest coverage ratio is not a measure of operating performance or liquidity defined by GAAP and may not be comparable to similarly titled measures presented by other companies.

Our current cash and investments, projected cash flows from operations, possible dispositions of non-core assets and our revolving credit facility are expected to adequately finance our purchase commitments, capital expenditures, acquisitions, scheduled debt service requirements, and all other expected cash requirements for the next 12 months.

See our discussion of the impact of changes in market conditions on our derivative financial instruments under Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

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Off-Balance Sheet Arrangements (Including Guarantees)

We are a party to some transactions, agreements or other contractual arrangements defined as off-balance sheet arrangements that could have a material future effect on our financial position, results of operations, liquidity and capital resources. The most significant of these off-balance sheet arrangements involve agreements and obligations under which we provide financial or performance assurance to third parties. Certain of these agreements serve as guarantees, including standby letters of credit issued on behalf of insurance carriers in conjunction with our workers compensation insurance program and other financial surety instruments such as bonds. In addition, we have provided indemnifications, which serve as guarantees, to some third parties. These guarantees include indemnification provided by Nabors to our share transfer agent and our insurance carriers. We are not able to estimate the potential future maximum payments that might be due under our indemnification guarantees.

Management believes the likelihood that we would be required to perform or otherwise incur any material losses associated with any of these guarantees is remote. The following table summarizes the total maximum amount of financial guarantees issued by Nabors:

	Maximum Amount				
	2013	2014	2015	Thereafter	Total
	(In thousands)				
Financial standby letters of credit and other financial surety instruments	$ 92,931	105			$ 93,036

Other Matters

Recent Accounting Pronouncements

In January 2012, we adopted the revised provisions from the Financial Accounting Standard Board s (FASB) Accounting Standard Update (ASU) relating to the presentation of other comprehensive income (OCI). We removed our historical presentation of OCI from the statement of changes in equity and included a statement of other comprehensive income (loss) for all periods presented. The presentation of the OCI statement did not have an impact on our consolidated financial statements.

In January 2012, we adopted the revised provisions from the ASU relating to goodwill impairment tests. Companies are allowed to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. They are not required to calculate the fair value of a reporting unit unless they determine, based on their qualitative assessment, that it is more likely than not that the fair value is less than its carrying amount. The application of these provisions did not have a material impact on our consolidated financial statements.

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Critical Accounting Estimates

The preparation of our financial statements in conformity with GAAP requires management to make certain estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosures of contingent assets and liabilities at the balance sheet date and the amounts of revenues and expenses recognized during the reporting period. We analyze our estimates based on our historical experience and various other assumptions that we believe to be reasonable under the circumstances. However, actual results could differ from our estimates. The following is a discussion of our critical accounting estimates. Management considers an accounting estimate to be critical if:

- it requires assumptions to be made that were uncertain at the time the estimate was made; and

- changes in the estimate or different estimates that could have been selected could have a material impact on our consolidated financial position or results of operations.

For a summary of all of our significant accounting policies, see Note 2 Summary of Significant Accounting Policies in Part II, Item 8. - Financial Statements and Supplementary Data.

Financial Instruments. As defined in the ASC, fair value is the price that would be received upon a sale of an asset or paid upon a transfer of a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market-corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best information available. Accordingly, we employ valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The use of unobservable inputs is intended to allow for fair value determinations in situations where there is little, if any, market activity for the asset or liability at the measurement date. We are able to classify fair value balances utilizing a fair-value hierarchy based on the observability of those inputs. Under the fair-value hierarchy:

- Level 1 measurements include unadjusted quoted market prices for identical assets or liabilities in an active market;

- Level 2 measurements include quoted market prices for identical assets or liabilities in an active market that have been adjusted for items such as effects of restrictions for transferability and those that are not quoted but are observable through corroboration with observable market data, including quoted market prices for similar assets; and

- Level 3 measurements include those that are unobservable and of a highly subjective nature.

Depreciation of Property, Plant and Equipment. The drilling, workover and well-servicing and pressure pumping industries are very capital intensive. Property, plant and equipment represented 68.8% of our total assets as of December 31, 2012, and depreciation constituted 16.3% of our total costs and other deductions in 2012.

Depreciation for our primary operating assets, drilling and workover rigs, is calculated based on the units-of-production method. For each day a rig is operating, we depreciate it over an approximate 4,900-day period, with the exception of our jackup rigs which are depreciated over an 8,030-day period, after provision for salvage value. For each day a rig asset is not operating, it is depreciated over an assumed depreciable life of 20 years, with the exception of our jackup rigs, where a 30-year depreciable life is typically used, after provision for salvage value.

Depreciation on our buildings, well-servicing rigs, oilfield hauling and mobile equipment, marine transportation and supply vessels, aircraft equipment, and other machinery and equipment is computed using the straight-line method over the estimated useful life of the asset after provision for salvage value (buildings 10 to 30 years; well-servicing rigs 3 to 15 years; marine transportation and supply vessels 10 to 25 years; aircraft equipment 5 to 20 years; oilfield hauling and mobile equipment and other machinery and equipment 3 to 10 years).

These depreciation periods and the salvage values of our property, plant and equipment were determined through an analysis of the useful lives of our assets and based on our experience with the salvage values of these assets. Periodically, we review our depreciation periods and salvage values for reasonableness given current conditions. Depreciation of property, plant and equipment is therefore based upon estimates of the useful lives and

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salvage value of those assets. Estimation of these items requires significant management judgment. Accordingly, management believes that accounting estimates related to depreciation expense recorded on property, plant and equipment are critical.

There have been no factors related to the performance of our portfolio of assets, changes in technology or other factors indicating that these estimates do not continue to be appropriate. Accordingly, for the years ended December 31, 2012, 2011 and 2010, no significant changes have been made to the depreciation rates applied to property, plant and equipment, the underlying assumptions related to estimates of depreciation, or the methodology applied. However, certain events could occur that would materially affect our estimates and assumptions related to depreciation. Unforeseen changes in operations or technology could substantially alter management s assumptions regarding our ability to realize the return on our investment in operating assets and therefore affect the useful lives and salvage values of our assets.

Impairment of Long-Lived Assets. As discussed above, the drilling, workover and well-servicing and pressure pumping industry is very capital intensive. We review our assets for impairment annually or when events or changes in circumstances indicate that their carrying amounts may not be recoverable. An impairment loss is recorded in the period in which it is determined that the sum of estimated future cash flows, on an undiscounted basis, is less than the carrying amount of the long-lived asset. Impairment charges are recorded using discounted cash flows, which requires the estimation of dayrates and utilization, and such estimates can change based on market conditions, technological advances in the industry or changes in regulations governing the industry. Significant and unanticipated changes to the assumptions could result in future impairments. As the determination of whether impairment charges should be recorded on our long-lived assets is subject to significant management judgment, and an impairment of these assets could result in a material charge on our consolidated statements of income (loss), management believes that accounting estimates related to impairment of long-lived assets are critical.

Assumptions made in the determination of future cash flows are made with the involvement of management personnel at the operational level where the most specific knowledge of market conditions and other operating factors exists. For 2012, 2011 and 2010, no significant changes have been made to the methodology utilized to determine future cash flows.

For an asset classified as held for sale, we consider the asset impaired when its carrying amount exceeds fair value less its cost to sell. Fair value is determined in the same manner as an impaired long-lived asset that is held and used.

Given the nature of the evaluation of future cash flows and the application to specific assets and specific times, it is not possible to reasonably quantify the impact of changes in these assumptions. A significantly prolonged period of lower oil and natural gas prices could adversely affect the demand for and prices of our services, which could result in future impairment charges.

Impairment of Goodwill and Intangible Assets. We review goodwill and intangible assets with indefinite lives for impairment annually or more frequently if events or changes in circumstances indicate that the carrying amount of such goodwill and intangible assets exceed their fair value. During the second quarter of 2012, we assessed qualitative factors and determined it was necessary to perform the two-step annual goodwill impairment test for all of our reporting units within our operating segments. Our Drilling & Rig Services business line consists of U.S. Lower 48 Land Drilling, U.S. Offshore, Alaska, Canada, International and Other Rig Services operating segments. Other Rig Services operating segment includes Canrig Drilling Technology Ltd., Peak Oilfield Services and Ryan Directional Services Inc. Our Completion & Production Services business line consists of U.S. Production Services and Completion Services operating segments. The impairment test involves comparing the estimated fair value of the reporting unit to its carrying amount. If the carrying amount of the reporting unit exceeds its fair value, a second step is required to measure the goodwill impairment loss. This second step compares the implied fair value of the reporting unit s goodwill to the carrying amount of that goodwill. If the carrying amount of the reporting unit s goodwill exceeds the implied fair value of the goodwill, an impairment loss is recognized in an amount equal to the excess. During 2012, we concluded that all our operating segments fair values were substantially in excess of their carrying value with the exception of U.S. Offshore and International operating segments. We performed the second step to measure the impairment for these two operating segments. The remaining operating segments each had an excess of fair value over carrying value of at least 10%.

The fair values calculated in these impairment tests are determined using discounted cash flow models involving assumptions based on our utilization of rigs or other oil and gas service equipment, revenues and earnings from affiliates, as well as direct costs, general and administrative costs, depreciation, applicable income taxes, capital expenditures and working capital requirements. Our discounted cash flow projections for each reporting unit were based on financial forecasts. The future cash flows were discounted to present value using discount rates that are determined to be appropriate for each reporting unit. Terminal values for each reporting unit were calculated using a Gordon Growth methodology with a long-term growth rate of 3%. We believe the fair value estimated for purposes of these tests represent a Level 3 fair value measurement.

During 2012 and 2010, we recognized goodwill impairments of approximately $26.3 million and $10.7 million, respectively. The impairment charges during 2012 eliminated the remaining goodwill of our U.S. Offshore and International operating segments. We deemed the goodwill impairment charges necessary due to the prolonged uncertainty of utilization of some of our rigs in the Gulf of Mexico as well as our international markets. We did not record any goodwill impairment in 2011.The impairment charge during 2010 was recorded in our U.S. Offshore operating segment and was deemed necessary due to the uncertainty of utilization of some of our rigs as a result of changes in our customers plans for future drilling operations in the Gulf of Mexico. Many of our customers had suspended drilling operations in the Gulf of Mexico, largely as a result of their inability to obtain government permits.

A significantly prolonged period of lower oil and natural gas prices or changes in laws and regulations could continue to adversely affect the demand for and prices of our services, which could result in future goodwill impairment charges for other reporting units due to the potential impact on our estimate of our future operating results.

Income Taxes. Deferred taxes represent a substantial liability for Nabors. For financial reporting purposes, management determines our current tax liability as well as those taxes incurred as a result of current operations yet deferred until future periods. In accordance with the liability method of accounting for income taxes as specified in the Income Taxes Topic of the ASC, the provision for income taxes is the sum of income taxes both currently payable and deferred. Currently payable taxes represent the liability related to our income tax return for the current year, while the net deferred tax expense or benefit represents the change in the balance of deferred tax assets or liabilities reported on our consolidated balance sheets. The tax effects of unrealized gains and losses on investments and derivative financial instruments are recorded through accumulated other comprehensive income (loss) within equity. The changes in deferred tax assets or liabilities are determined based upon changes in differences between the basis of assets and liabilities for financial reporting purposes and the basis of assets and liabilities for tax purposes as measured by the enacted tax rates that management estimates will be in effect when these differences reverse. Management must make certain assumptions regarding whether tax differences are permanent or temporary and must estimate the timing of their reversal, and whether taxable operating income in future periods will be sufficient to fully recognize any gross deferred tax assets. Valuation allowances are established to reduce deferred tax assets when it is more likely than not that some portion or all of the deferred tax assets will not be realized. In determining the need for valuation allowances, management has considered and made judgments and estimates regarding estimated future taxable income and ongoing prudent and feasible tax planning strategies. These judgments and estimates are made for each tax jurisdiction where we operate as the calculation of deferred taxes is completed at that level. Under U.S. federal tax law, the amount and availability of loss carryforwards (and certain other tax attributes) are subject to a variety of interpretations and restrictive tests applicable to Nabors and our subsidiaries. The utilization of these carryforwards could be limited or effectively lost upon certain changes in ownership. Accordingly, although we believe substantial loss carryforwards are available to us, no assurance can be given concerning their realization or whether or not they will be available in the future. These loss carryforwards are also considered in our calculation of taxes for each jurisdiction in which we operate. Additionally, we record reserves for uncertain tax positions that are subject to a significant level of management judgment related to the ultimate resolution of those tax positions. Accordingly, management believes that the estimate related to the provision for income taxes is critical to our results of operations. See Part I, Item 1A. Risk Factors *We may have additional tax liabilities* and Note 13 Income Taxes in Part II, Item 8. Financial Statements and Supplementary Data for additional discussion.

We are subject to income taxes in the United States and numerous other jurisdictions. Significant judgment is required in determining our worldwide provision for income taxes. In the ordinary course of our business, there are many transactions and calculations where the ultimate tax determination is uncertain. We are regularly audited by tax authorities. Although we believe our tax estimates are reasonable, the final determination of tax audits and any related litigation could be materially different than that reflected in historical income tax provisions and accruals. An audit or litigation could materially affect our financial position, income tax provision, net income, or cash flows in the period or periods challenged. However, certain events could occur that would materially affect management s estimates and assumptions regarding the deferred portion of our income tax provision, including estimates of future tax rates applicable to the reversal of tax differences, the classification of timing differences as temporary or permanent, reserves recorded for uncertain tax positions and any valuation allowance recorded as a reduction to our deferred tax assets. Management s assumptions related to the preparation of our income tax provision have historically proved to be reasonable in light of the ultimate amount of tax liability due in all taxing jurisdictions.

Our 2012 provision for income taxes from continuing operations was $32.6 million, consisting of $143.0 million of current tax expense and $110.4 million of deferred tax benefit. Changes in management s estimates and assumptions regarding the tax rate applied to deferred tax assets and liabilities, the ability to realize the value of deferred tax assets, or the timing of the reversal of tax basis differences could potentially impact the provision for income taxes and could potentially change the effective tax rate. A 1% change in the effective tax rate from 11.9% to 12.9% would increase the current year income tax provision by approximately $2.8 million.

Litigation and Self-Insurance Reserves. Our operations are subject to many hazards inherent in the drilling, workover and well-servicing and pressure pumping industries, including blowouts, cratering, explosions, fires, loss of well control, loss of or damage to the wellbore or underground reservoir, damaged or lost drilling equipment and damage or loss from inclement weather or natural disasters. Any of these hazards could result in personal injury or death, damage to or destruction of equipment and facilities, suspension of operations, environmental and natural resources damage and damage to the property of others. Our offshore operations are also subject to the hazards of marine operations including capsizing, grounding, collision and other damage from hurricanes and heavy weather or sea conditions and unsound ocean bottom conditions. Our operations are subject to risks of war, civil disturbances and other political events.

Accidents may occur, we may be unable to obtain desired contractual indemnities, and our insurance may prove inadequate in certain cases. There is no assurance that our insurance or indemnification agreements will adequately protect us against liability from all of the consequences of the hazards described above. Moreover, our insurance coverage generally provides that we assume a portion of the risk in the form of a deductible or self-insured retention.

Based on the risks discussed above, it is necessary for us to estimate the level of our liability related to insurance and record reserves for these amounts in our consolidated financial statements. Reserves related to self-insurance are based on the facts and circumstances specific to the claims and our past experience with similar claims. The actual outcome of self-insured claims could differ significantly from estimated amounts. We maintain actuarially determined accruals in our consolidated balance sheets to cover self-insurance retentions for workers compensation, employers liability, general liability and automobile liability claims. These accruals are based on certain assumptions developed utilizing historical data to project future losses. Loss estimates in the calculation of these accruals are adjusted based upon actual claim settlements and reported claims. These loss estimates and accruals recorded in our financial statements for claims have historically been reasonable in light of the actual amount of claims paid.

Because the determination of our liability for self-insured claims is subject to significant management judgment and in certain instances is based on actuarially estimated and calculated amounts, and because such liabilities could be material in nature, management believes that accounting estimates related to self-insurance reserves are critical.

During 2012, 2011 and 2010, no significant changes were made to the methodology used to estimate insurance reserves. For purposes of earnings sensitivity analysis, if the December 31, 2012 reserves for insurance were adjusted by 10%, total costs and other deductions would change by $17.1 million, or 0.3%.

Fair Value of Assets Acquired and Liabilities Assumed. We have completed a number of acquisitions in recent years as discussed in Note 7 Fair Value Measurements in Part II, Item 8. Financial Statements and Supplementary Data. In conjunction with our accounting for these acquisitions, it was necessary for us to estimate the values of the assets acquired and liabilities assumed in the various business combinations using various assumptions. These estimates may be affected by such factors as changing market conditions, technological advances in the industry or changes in regulations governing the industry. The most significant assumptions, and the

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ones requiring the most judgment, involve the estimated fair values of property, plant and equipment, and the resulting amount of goodwill, if any. Unforeseen changes in operations or technology could substantially alter management s assumptions and could result in lower estimates of values of acquired assets or of future cash flows. This could result in impairment charges being recorded in our consolidated statements of income (loss). As the determination of the fair value of assets acquired and liabilities assumed is subject to significant management judgment and a change in purchase price allocations could result in a material difference in amounts recorded in our consolidated financial statements, management believes that accounting estimates related to the valuation of assets acquired and liabilities assumed are critical.

The determination of the fair value of assets and liabilities is based on the market for the assets and the settlement value of the liabilities. These estimates are made by management based on our experience with similar assets and liabilities. During 2012, 2011 and 2010, no significant changes were made to the methodology utilized to value assets acquired or liabilities assumed. Our estimates of the fair values of assets acquired and liabilities assumed have proved to be reliable in the past.

Given the nature of the evaluation of the fair value of assets acquired and liabilities assumed and the application to specific assets and liabilities, it is not possible to reasonably quantify the impact of changes in these assumptions.

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ITEM 7A. ***QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK***

We may be exposed to certain market risks arising from the use of financial instruments in the ordinary course of business. This risk arises primarily as a result of potential changes in the fair market value of financial instruments due to adverse fluctuations in foreign currency exchange rates, credit risk, interest rates, and marketable and non-marketable security prices as discussed below.

Foreign Currency Risk. We operate in a number of international areas and are involved in transactions denominated in currencies other than U.S. dollars, which exposes us to foreign exchange rate risk and foreign currency devaluation risk. The most significant exposures arise in connection with our operations in Venezuela and Canada, which usually are substantially unhedged.

At various times, we utilize local currency borrowings (foreign-currency-denominated debt), the payment structure of customer contracts and foreign exchange contracts to selectively hedge our exposure to exchange rate fluctuations in connection with monetary assets, liabilities, cash flows and commitments denominated in certain foreign currencies. A foreign exchange contract is a foreign currency transaction, defined as an agreement to exchange different currencies at a given future date and at a specified rate. A hypothetical 10% decrease in the value of all our foreign currencies relative to the U.S. dollar as of December 31, 2012 would result in a $10.5 million decrease in the fair value of our net monetary assets denominated in currencies other than U.S. dollars.

Credit Risk. Our financial instruments that potentially subject us to concentrations of credit risk consist primarily of cash equivalents, short-term and long-term investments and accounts receivable. Cash equivalents such as deposits and temporary cash investments are held by major banks or investment firms. Our short-term and long-term investments are managed within established guidelines that limit the amounts that may be invested with any one issuer and provide guidance as to issuer credit quality. We believe that the credit risk in our cash and investment portfolio is minimized as a result of the mix of our investments. In addition, our trade receivables are with a variety of U.S., international and foreign-country national oil and gas companies. Management considers this credit risk to be limited due to the financial resources of these companies. We perform ongoing credit evaluations of our customers, and we generally do not require material collateral. We do occasionally require prepayment of amounts from customers whose creditworthiness is in question prior to providing services to them. We maintain reserves for potential credit losses, and these losses historically have been within management s expectations.

Interest Rate, and Marketable and Non-marketable Security Price Risk. Our financial instruments that are potentially sensitive to changes in interest rates include our 6.15%, 9.25%, 5.0% and 4.625% senior notes, our investments in debt securities (including corporate, asset-backed, mortgage-backed debt and mortgage-CMO debt securities) and our investments in overseas funds that invest primarily in a variety of public and private U.S. and non-U.S. securities (including asset-backed and mortgage-backed securities, global structured-asset securitizations, whole-loan mortgages, and participations in whole loans and whole-loan mortgages), which are classified as long-term investments.

We may utilize derivative financial instruments that are intended to manage our exposure to interest rate risks. We account for derivative financial instruments under the Derivatives Topic of the ASC. The use of derivative financial instruments could expose us to further credit risk and market risk. Credit risk in this context is the failure of a counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty would owe us, which can create credit risk for us. When the fair value of a derivative contract is negative, we would owe the counterparty, and therefore, we would not be exposed to credit risk. We attempt to minimize credit risk in derivative instruments by entering into transactions with major financial institutions that have a significant asset base. Market risk related to derivatives is the adverse effect on the value of a financial instrument that results from changes in interest rates. We try to manage market risk associated with interest-rate contracts by establishing and monitoring parameters that limit the type and degree of market risk that we undertake.

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Fair Value of Financial Instruments. We estimate the fair value of our financial instruments in accordance with the provisions of the Fair Value Measurements and Disclosures Topic of the ASC. The fair value of our fixed rate long-term debt and subsidiary preferred stock is estimated based on quoted market prices or prices quoted from third-party financial institutions. The carrying and fair values of these liabilities were as follows:

	December 31, 2012			December 31, 2011		
	Effective Interest Rate	Carrying Value	Fair Value	Effective Interest Rate	Carrying Value	Fair Value
	(In thousands)					
6.15% senior notes due February 2018	6.42%	$ 968,708	$ 1,164,813	6.42%	$ 967,490	$ 1,113,986
9.25% senior notes due January 2019	9.33%	1,125,000	1,492,819	9.33%	1,125,000	1,419,514
5.00% senior notes due September 2020	5.20%	697,648	770,707	5.20%	697,343	734,475
4.625% senior notes due September 2021	4.75%	697,907	755,517	4.75%	697,667	708,176
5.375% senior notes due August 2012	0.00%			5.61%	274,604	281,188
Subsidiary preferred stock	4.00%	69,188	68,625	4.00%	69,188	68,625
Revolving credit facilities	2.17%	890,000	890,000	2.35%	860,000	860,000
Other	0.00%	437	437	0.00%	1,712	1,712
		$ 4,448,888	$ 5,142,918		$ 4,693,004	$ 5,187,676

The fair values of our cash equivalents, trade receivables and trade payables approximate their carrying values due to the short-term nature of these instruments. Our cash, cash equivalents, short-term and long-term investments and other receivables are included in the table below:

	December 31, 2012			December 31, 2011		
	Fair Value	Interest Rates	Weighted-Average Life (Years)	Fair Value	Interest Rates	Weighted-Average Life (Years)
	(In thousands, except rates)					
Cash and cash equivalents	$ 524,922	0 - .22%	0.0	$ 398,575	0 - .21%	0.0
Short-term investments:						
Trading equity securities	52,705			11,600		
Available-for-sale equity securities	174,610			71,433		
Available-for-sale debt securities:						
Commercial paper and CDs	206	1.0%	0.6	1,230	1.0%	0.6
Corporate debt securities	23,399	10.0-14.0%	4.3	51,300	10.01-13.98%	2.5
Mortgage-backed debt securities	244	2.75%	0.7	309	2.4%	1.7
Mortgage-CMO debt securities	523	.32-4.09%	0.3	2,547	.44-5.9%	0.2
Asset-backed debt securities	1,595	.71-4.81%	3.8	2,495	.78-4.8%	0.8
	25,967			57,881		

Total available-for-sale debt securities						
Total available-for-sale securities		200,577			129,314	
Total short-term investments		253,282			140,914	
Long-term investments		4,269	N/A		5,941	N/A
Total cash, cash equivalents, short-term and long-term investments	$	782,473		$	545,430	

Our investments in debt securities listed in the above table and a portion of our long-term investments are sensitive to changes in interest rates. Additionally, our investment portfolio of debt and equity securities, which are carried at fair value, exposes us to price risk. A hypothetical 10% decrease in the market prices for all securities as of December 31, 2012 would decrease the fair value of our trading securities and available-for-sale securities by $5.3 million and $20.1 million, respectively.

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ITEM 8. ***FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA***

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders

of Nabors Industries Ltd.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income (loss), other comprehensive income (loss), changes in equity and cash flows present fairly, in all material respects, the financial position of Nabors Industries Ltd. and its subsidiaries (the Company) at December 31, 2012 and December 31, 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed 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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Houston, Texas

March 1, 2013

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NABORS INDUSTRIES LTD. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2012	December 31, 2011
	(In thousands, except per share amounts)	
ASSETS		
Current assets:		
Cash and short-term investments	$ 524,922	$ 398,575
Short-term investments	253,282	140,914
Assets held for sale	383,857	401,500
Accounts receivable, net	1,382,623	1,576,555
Inventory	251,133	272,852
Deferred income taxes	110,480	127,874
Other current assets	226,560	170,044
Total current assets	3,132,857	3,088,314
Long-term investments	4,269	11,124
Property, plant and equipment, net	8,712,088	8,629,946
Goodwill	472,326	501,258
Investment in unconsolidated affiliates	61,690	371,021
Other long-term assets	272,792	310,477
Total assets	$ 12,656,022	$ 12,912,140
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 364	$ 275,326
Trade accounts payable	499,010	782,753
Accrued liabilities	599,380	716,773
Income taxes payable	33,628	27,710
Total current liabilities	1,132,382	1,802,562
Long-term debt	4,379,336	4,348,490
Other long-term liabilities	518,664	292,758
Deferred income taxes	599,335	797,925
Total liabilities	6,629,717	7,241,735
Commitments and contingencies (Note 18)		
Subsidiary preferred stock (Notes 5 and 15)	69,188	69,188
Equity:		
Shareholders equity:		
Common shares, par value $0.001 per share:		
Authorized common shares 800,000; issued 318,813 and 317,042, respectively	319	317
Capital in excess of par value	2,337,244	2,287,743
Accumulated other comprehensive income	431,595	321,264
Retained earnings	4,120,398	3,956,364
Less: treasury shares, at cost, 28,414 and 29,414 common shares, respectively	(944,627)	(977,873)
Total shareholders equity	5,944,929	5,587,815
Noncontrolling interest	12,188	13,402
Total equity	5,957,117	5,601,217
Total liabilities and equity	$ 12,656,022	$ 12,912,140

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

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NABORS INDUSTRIES LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME (LOSS)

	Year Ended December 31, 2012	2011	2010
	(In thousands, except per share amounts)		
Revenues and other income:			
Operating revenues	$ 6,989,573	$ 6,060,351	$ 4,134,483
Earnings (losses) from unconsolidated affiliates	(301,320)	56,647	33,267
Investment income (loss)	63,137	19,940	7,263
Total revenues and other income	6,751,390	6,136,938	4,175,013
Costs and other deductions:			
Direct costs	4,483,320	3,775,964	2,400,519
General and administrative expenses	532,568	489,892	338,720
Depreciation and amortization	1,055,517	924,094	760,962
Interest expense	251,552	256,633	272,712
Losses (gains) on sales and disposals of long-lived assets and other expense (income), net	(136,510)	4,514	47,238
Impairments and other charges	290,260	198,072	61,292
Total costs and other deductions	6,476,707	5,649,169	3,881,443
Income (loss) from continuing operations before income taxes	274,683	487,769	293,570
Income tax expense (benefit):			
Current	142,994	109,702	(77,209)
Deferred	(110,366)	32,903	114,159
Total income tax expense (benefit)	32,628	142,605	36,950
Subsidiary preferred stock dividend	3,000	3,000	750
Income (loss) from continuing operations, net of tax	239,055	342,164	255,870
Income (loss) from discontinued operations, net of tax	(74,400)	(97,440)	(161,090)
Net income (loss)	164,655	244,724	94,780
Less: Net (income) loss attributable to noncontrolling interest	(621)	(1,045)	(85)
Net income (loss) attributable to Nabors	$ 164,034	$ 243,679	$ 94,695
Earnings (losses) per share:			
Basic from continuing operations	$ 0.82	$ 1.19	$ 0.90
Basic from discontinued operations	(0.25)	(0.34)	(0.57)
Total Basic	$ 0.57	$ 0.85	$ 0.33
Diluted from continuing operations	$ 0.82	$ 1.17	$ 0.88
Diluted from discontinued operations	(0.26)	(0.34)	(0.55)
Total Diluted	$ 0.56	$ 0.83	$ 0.33
Weighted-average number of common shares outstanding:			
Basic	289,965	287,118	285,145
Diluted	292,323	292,484	289,996

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

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NABORS INDUSTRIES LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OTHER COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31, 2012	2011 (In thousands)	2010
Net income (loss) attributable to Nabors	$ 164,034	$ 243,679	$ 94,695
Other comprehensive income (loss), before tax:			
Translation adjustment attributable to Nabors	21,073	(20,257)	60,897
Unrealized gains/(losses) on marketable securities	98,138	5,356	278
Less: reclassification adjustment for (gains)/losses included in net income (loss)	(13,405)	(3,036)	(1,694)
Unrealized gains/(losses) on marketable securities	84,733	2,320	(1,416)
Pension liability amortization	(324)	(5,391)	(376)
Unrealized gains/(losses) on cash flow hedges	702	763	(5,282)
Other comprehensive income (loss), before tax	106,184	(22,565)	53,823
Income tax expense (benefit) related to items of other comprehensive income (loss)	(4,147)	(1,777)	4,477
Other comprehensive income (loss), net of tax	110,331	(20,788)	49,346
Comprehensive income (loss) attributable to Nabors	274,365	222,891	144,041
Net income (loss) attributable to noncontrolling interest	621	1,045	85
Translation adjustment attributable to noncontrolling interest	311	(185)	723
Comprehensive income (loss) attributable to noncontrolling interest	932	860	808
Comprehensive income (loss)	$ 275,297	$ 223,751	$ 144,849

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

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NABORS INDUSTRIES LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2012	2011	2010
	(In thousands)		
Cash flows from operating activities:			
Net income (loss) attributable to Nabors	$ 164,034	$ 243,679	$ 94,695
Adjustments to net income (loss):			
Depreciation and amortization	1,055,757	927,460	766,519
Depletion and other exploratory expenses	2,573	44,551	27,002
Deferred income tax expense (benefit)	(145,147)	(34,739)	55,964
Deferred financing costs amortization	4,294	5,107	5,431
Pension liability amortization and adjustments	1,064	818	664
Discount amortization on long-term debt	1,908	27,042	70,719
Amortization of loss on hedges	695	927	786
Impairments and other charges	311,541	460,971	260,931
Losses (gains) on long-lived assets, net	(51,585)	(51,945)	(1,050)
Losses (gains) on investments, net	(56,925)	(12,486)	191
Losses (gains) on debt retirement, net		58	7,042
Losses (gains) on derivative instruments	103	234	2,471
Gains on acquisitions		(13,114)	
Share-based compensation	18,312	21,244	13,746
Foreign currency transaction losses (gains), net	4,819	5,725	17,880
Equity in (earnings) losses of unconsolidated affiliates, net of dividends	312,319	(132,388)	(13,630)
Changes in operating assets and liabilities, net of effects from acquisitions:			
Accounts receivable	200,537	(459,455)	(249,725)
Inventory	14,447	(114,896)	(15,201)
Other current assets	(42,743)	(24,820)	6,589
Other long-term assets	(38,468)	71,867	7,509
Trade accounts payable and accrued liabilities	(223,199)	517,615	70,463
Income taxes payable	(1,488)	999	(19,208)
Other long-term liabilities	29,857	(27,967)	(2,804)
Net cash provided by operating activities	1,562,705	1,456,487	1,106,984
Cash flows from investing activities:			
Purchases of investments	(949)	(11,746)	(34,147)
Sales and maturities of investments	31,944	39,063	34,613
Proceeds from sale of unconsolidated affiliates	159,529	142,984	
Cash paid for acquisition of businesses, net		(55,459)	(733,630)
Investment in unconsolidated affiliates	(1,325)	(112,262)	(40,936)
Capital expenditures	(1,518,628)	(2,042,617)	(930,277)
Proceeds from sales of assets and insurance claims	149,801	180,558	31,072
Net cash used for investing activities	(1,179,628)	(1,859,479)	(1,673,305)
Cash flows from financing activities:			
Increase (decrease) in cash overdrafts	1,612	6,375	(6,298)
Proceeds from issuance of long-term debt		697,578	696,948
Debt issuance costs	(3,433)	(7,141)	(8,934)
Payments for hedge transactions			(5,667)
Proceeds from revolving credit facilities	710,000	1,560,000	600,000
Proceeds from (payments for) issuance of common shares	(3,625)	11,605	8,201
Reduction in long-term debt	(276,258)	(1,404,281)	(398,514)

Reduction in revolving credit facilities		(680,000)		(700,000)		(600,000)
Repurchase of equity component of convertible debt				(12)		(4,712)
Settlement of call options and warrants, net						1,134
Purchase of restricted stock		(2,160)		(2,626)		(1,935)
Tax (expense) benefit related to share-based awards		(263)		1,747		31
Net cash (used for) provided by financing activities		(254,127)		163,245		280,254
Effect of exchange rate changes on cash and cash equivalents		(2,603)		(3,380)		(46)
Net increase (decrease) in cash and cash equivalents		126,347		(243,127)		(286,113)
Cash and cash equivalents, beginning of period		398,575		641,702		927,815
Cash and cash equivalents, end of period	$	524,922	$	398,575	$	641,702

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

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NABORS INDUSTRIES LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(In thousands)	Common Shares Shares	Common Shares Par Value	Capital in Excess of Par Value	Accumulated Other Comprehensive Income	Retained Earnings	Treasury Shares	Non-controlling Interest	Total Equity
As of December 31, 2009	313,915	$ 314	$ 2,239,323	$ 292,706	$ 3,613,186	$ (977,873)	$ 14,323	$ 5,181,979
Net income (loss)					94,695		85	94,780
Other Comprehensive income (loss), net of tax				49,346			723	50,069
Issuance of common shares for stock options exercised, net of surrender of unexercised stock options	714	1	8,200					8,201
Share-based compensation			13,746					13,746
Other	405		(5,482)				(430)	(5,912)
As of December 31, 2010	315,034	$ 315	$ 2,255,787	$ 342,052	$ 3,707,881	$ (977,873)	$ 14,701	$ 5,342,863
Net income (loss)					243,679		1,045	244,724
Other Comprehensive income (loss), net of tax				(20,788)			(185)	(20,973)
Issuance of common shares for stock options exercised, net of surrender of unexercised stock options	1,116	1	11,604					11,605
Share-based compensation			21,244					21,244
Other	892	1	(892)		4,804		(2,159)	1,754
As of December 31, 2011	317,042	$ 317	$ 2,287,743	$ 321,264	$ 3,956,364	$ (977,873)	$ 13,402	$ 5,601,217
Net income (loss)					164,034		621	164,655
Other Comprehensive income (loss), net of tax				110,331			311	110,642
Issuance of common shares for stock options exercised, net of surrender of unexercised stock options	1,152	1	(3,626)					(3,625)
Capital contribution from forgiveness of liability, net of tax			62,734					62,734
Issuance of treasury shares, net of tax benefit			(25,496)			33,246		7,750
Share-based compensation			18,312					18,312
Other	619	1	(2,423)				(2,146)	(4,568)
As of December 31, 2012	318,813	$ 319	$ 2,337,244	$ 431,595	$ 4,120,398	$ (944,627)	$ 12,188	$ 5,957,117

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

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Nabors Industries Ltd. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Nature of Operations

Nabors is the largest land drilling contractor in the world and one of the largest land well-servicing and workover contractors in the United States and Canada:

- We actively market approximately 474 land drilling rigs for oil and gas land drilling operations in the U.S. Lower 48 states, Alaska, Canada and over 20 other countries throughout the world.

- We actively market approximately 442 rigs for land well-servicing and workover work in the United States and approximately 106 rigs for land well-servicing and workover work in Canada.

We are also a leading provider of offshore platform workover and drilling rigs, and actively market 36 platform, 12 jackup and 4 barge rigs in the United States, including the Gulf of Mexico, and multiple international markets.

In addition to the foregoing services:

- We provide completion and production services, including hydraulic fracturing, cementing, nitrogen and acid pressure pumping services with over 805,000 hydraulic horsepower in key basins throughout the United States and Canada.

- We offer a wide range of ancillary well-site services, including engineering, transportation and disposal, construction, maintenance, well logging, directional drilling, rig instrumentation, data collection and other support services in select U.S. and international markets.

- We manufacture and lease or sell top drives for a broad range of drilling applications, directional drilling systems, rig instrumentation and data collection equipment, pipeline handling equipment and rig reporting software.

- We have a 51% ownership interest in a joint venture in Saudi Arabia, which owns and actively markets nine rigs in addition to the rigs we lease to the joint venture.

The majority of our business is conducted through two business lines:

- Our Drilling & Rig Services business line includes our drilling operations for oil and natural gas wells, on land and offshore, and companies engaged in drilling technology, top drive manufacturing, directional drilling, construction services, and rig instrumentation and software.

- Our Completion & Production Services business line includes our well-servicing, fluid logistics, workover operations and our pressure pumping services.

The consolidated financial statements and related footnotes are presented in accordance with GAAP.

Note 2 Summary of Significant Accounting Policies

Principles of Consolidation

Our consolidated financial statements include the accounts of Nabors, as well as all majority owned and non-majority owned subsidiaries required to be consolidated under GAAP. All significant intercompany accounts and transactions are eliminated in consolidation.

Investments in operating entities where we have the ability to exert significant influence, but where we do not control operating and financial policies, are accounted for using the equity method. Our share of the net income (loss) of these entities is recorded as earnings (losses) from unconsolidated affiliates in our consolidated statements

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of income (loss). The investments in these entities are included in investment in unconsolidated affiliates in our consolidated balance sheets.

Cash and Cash Equivalents

Cash and cash equivalents include demand deposits and various other short-term investments with original maturities of three months or less.

Investments

Short-term investments

Short-term investments consist of equity securities, certificates of deposit, corporate debt securities, mortgage-backed debt securities and asset-backed debt securities. Securities classified as available-for-sale or trading are stated at fair value. Unrealized holding gains and temporary losses for available-for-sale securities are excluded from earnings and, until realized, are presented in the statement of other comprehensive income (loss). Unrealized holding losses are included in earnings during the period for which the loss is determined to be other-than-temporary. Gains and losses from changes in the market value of securities classified as trading are reported in earnings currently.

In computing realized gains and losses on the sale of equity securities, the specific-identification method is used. In accordance with this method, the cost of the equity securities sold is determined using the specific cost of the security when originally purchased.

Long-term investments and other receivables

We have investments in overseas funds that invest primarily in a variety of public and private U.S. and non-U.S. securities (including asset-backed and mortgage-backed securities, global structured-asset securitizations, whole-loan mortgages, and participations in whole loans and whole-loan mortgages). These investments are non-marketable and do not have published fair values. The fair value of these investments approximates their carrying value and totaled $4.3 million and $5.9 million as of December 31, 2012 and 2011, respectively.

Inventory

Inventory is stated at the lower of cost or market. Cost is determined using the first-in, first-out method and includes the cost of materials, labor and manufacturing overhead. Inventory included the following:

	December 31, 2012		December 31, 2011	
	(In thousands)			
Raw materials	$	148,822	$	133,480
Work-in-progress		45,733		50,951
Finished goods		56,578		88,421
	$	251,133	$	272,852

Property, Plant and Equipment

Property, plant and equipment, including renewals and betterments, are stated at cost, while maintenance and repairs are expensed currently. Interest costs applicable to the construction of qualifying assets are capitalized as a component of the cost of such assets. We provide for the depreciation of our drilling and workover rigs using the units-of-production method. For each day a rig is operating, we depreciate it over an approximate 4,900-day period, with the exception of our jackup rigs which are depreciated over an 8,030-day period, after provision for salvage value. For each day a rig asset is not operating, it is depreciated over an assumed depreciable life of 20 years, with the exception of our jackup rigs, where a 30-year depreciable life is used, after provision for salvage value.

Depreciation on our buildings, well-servicing rigs, oilfield hauling and mobile equipment, marine transportation and supply vessels, and other machinery and equipment is computed using the straight-line method over the estimated useful life of the asset after provision for salvage value (buildings 10 to 30 years; well-servicing rigs 3 to 15 years; marine transportation and supply vessels 10 to 25 years; oilfield hauling and mobile equipment and other machinery and equipment 3 to 10 years). Amortization of capitalized leases is included in depreciation and amortization expense. Upon retirement or other disposal of fixed assets, the cost and related accumulated depreciation are removed from the respective accounts and any gains or losses are included in our results of operations.

We review our assets for impairment annually or when events or changes in circumstances indicate that their carrying amounts may not be recoverable. An impairment loss is recorded in the period in which it is determined that the sum of estimated future cash flows, on an undiscounted basis, is less than the carrying amount of the long-lived asset. Impairment charges are recorded using discounted cash flows which requires the estimation of dayrates and utilization, and such estimates can change based on market conditions, technological advances in the industry or changes in regulations governing the industry.

For an asset classified as held for sale, we consider the asset impaired when its carrying amount exceeds fair value less its cost to sell. Fair value is determined in the same manner as an impaired long-lived asset that is held and used.

Significant and unanticipated changes to the assumptions could result in future impairments. A significantly prolonged period of lower oil and natural gas prices could adversely affect the demand for and prices of our services, which could result in future impairment charges. As the determination of whether impairment charges should be recorded on our long-lived assets is subject to significant management judgment, and an impairment of these assets could result in a material charge on our consolidated statements of income (loss), management believes that accounting estimates related to impairment of long-lived assets are critical.

Goodwill

Effective January 1, 2012, we changed the manner in which we initially assess goodwill for impairment. We assessed qualitative factors and determined it was necessary to perform the two-step annual goodwill impairment test, a Level 3 fair value measurement, during 2012. The impairment test compares the estimated fair value of the reporting unit to its carrying amount. If the carrying amount exceeds the fair value, a second step is required to measure the goodwill impairment loss. The second step compares the implied fair value of the reporting unit s goodwill to its carrying amount. If the carrying amount exceeds the implied fair value, an impairment loss is recognized in an amount equal to the excess. Our goodwill impairment test results required measurement for two reporting units. Our remaining operating segment s fair values had an excess of fair value greater than 10% of their carrying value.

The fair values calculated in these impairment tests were determined using discounted cash flow models involving assumptions based on our utilization of rigs or other oil and gas service equipment, revenues and earnings from affiliates, as well as direct costs, general and administrative costs, depreciation, applicable income taxes, capital expenditures and working capital requirements. Our discounted cash flow projections for each reporting unit were based on financial forecasts. The future cash flows were discounted to present value using discount rates determined to be appropriate for each reporting unit. Terminal values for each reporting unit were calculated using a Gordon Growth methodology with a long-term growth rate of 3%.

Our estimated fair values of our reporting units incorporate judgment and the use of estimates by management. Potential factors requiring assessment include a further or sustained decline in our stock price, declines in oil and natural gas prices, a variance in results of operations from forecasts, and additional transactions in the oil and gas industry. Another factor in determining whether impairment has occurred is the relationship between our market capitalization and our book value. As part of our annual review, we compared the sum of our reporting units estimated fair value, which included the estimated fair value of non-operating assets and liabilities, less debt, to our market capitalization and assessed the reasonableness of our estimated fair value. Any of the above-mentioned factors may cause us to re-evaluate goodwill during any quarter throughout the year.

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The change in the carrying amount of goodwill for our business lines for the years ended December 31, 2012 and 2011 was as follows:

	Balance at December 31, 2010	Acquisitions and Purchase Price Adjustments	Disposals and Impairments (In thousands)	Cumulative Translation Adjustment	Balance at December 31, 2011
Drilling & Rig Services:					
U.S. Lower 48 Land Drilling	$ 30,154	$	$	$	$ 30,154
U.S. Offshore	7,296				7,296
Alaska	19,995				19,995
International	18,983				18,983
Other Rig Services	27,113	8,000(1)		(347)	34,766
Subtotal Drilling & Rig Services	103,541	8,000		(347)	111,194
Completion & Production Services	390,831	(767)(2)			390,064
Total	$ 494,372	$ 7,233	$	$ (347)	$ 501,258

	Balance at December 31, 2011	Acquisitions and Purchase Price Adjustments	Disposals and Impairments (In thousands)	Cumulative Translation Adjustment	Balance at December 31, 2012
Drilling & Rig Services:					
U.S. Lower 48 Land Drilling	$ 30,154	$	$	$	$ 30,154
U.S. Offshore	7,296		(7,296)(3)		
Alaska	19,995				19,995
International	18,983		(18,983)(3)		
Other Rig Services	34,766		(3,035)(4)	382	32,113
Subtotal Drilling & Rig Services	111,194		(29,314)	382	82,262
Completion & Production Services	390,064				390,064
Total	$ 501,258	$	$ (29,314)	$ 382	$ 472,326

(1) Represents the goodwill recorded in connection with our acquisition of the remaining 50 percent equity interest of Peak. See Note 5 Acquisitions for additional discussion.

(2) Represents an adjustment to the goodwill recorded in connection with our acquisition of Energy Contractors.

(3) Represents the impairment of goodwill associated with our U.S. Offshore and International reporting units. As of December 31, 2012, these reporting units had no recorded goodwill. See Note 3 Impairments and Other Charges for additional discussion.

(4) Represents the removal of goodwill in connection with our sale of Peak USA to an unrelated third party for $13.5 million cash during the second quarter of 2012. Peak USA, a subsidiary included in our Other Rig Services reporting unit, provided trucking and logistics services to the oilfield service market in the U.S. Lower 48 states.

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Goodwill for the consolidated company, totaling approximately $11.5 million, is expected to be deductible for tax purposes.

Litigation and Insurance Reserves

We estimate our reserves related to litigation and insurance based on the facts and circumstances specific to the litigation and insurance claims and our past experience with similar claims. We maintain actuarially determined accruals in our consolidated balance sheets to cover self-insurance retentions. See Note 18 Commitments and Contingencies regarding self-insurance accruals. We estimate the range of our liability related to pending litigation when we believe the amount and range of loss can reasonably be estimated. We record our best estimate of a loss when the loss is considered probable. When a liability is probable and there is a range of estimated loss with no best estimate in the range, we record the minimum estimated liability related to the lawsuits or claims. As additional information becomes available, we assess the potential liability related to our pending litigation and claims and revise our estimates. Due to uncertainties related to the resolution of lawsuits and claims, the ultimate outcome may differ from our estimates. For matters where an unfavorable outcome is reasonably possible and significant, we disclose the nature of the matter and a range of potential exposure, unless an estimate cannot be made at the time of disclosure.

Revenue Recognition

We recognize revenues and costs on daywork contracts daily as the work progresses. For certain contracts, we receive lump-sum payments for the mobilization of rigs and other drilling equipment. We defer revenue related to mobilization periods and recognize the revenue over the term of the related drilling contract. Costs incurred related to a mobilization period for which a contract is secured are deferred and recognized over the term of the related drilling contract. Costs incurred to relocate rigs and other drilling equipment to areas in which a contract has not been secured are expensed as incurred. We defer recognition of revenue on amounts received from customers for prepayment of services until those services are provided.

We recognize revenue for top drives and instrumentation systems we manufacture when the earnings process is complete. This generally occurs when products have been shipped, title and risk of loss have been transferred, collectability is probable, and pricing is fixed and determinable.

In connection with the performance of our cementing services, we recognize product and service revenue when the products are delivered or services are provided to the customer and collectability is reasonably assured. Product sale prices are determined by published price lists provided to our customers.

We recognize, as operating revenue, proceeds from business interruption insurance claims in the period that the applicable proof of loss documentation is received. Proceeds from casualty insurance settlements in excess of the carrying value of damaged assets are recognized in losses (gains) on sales and disposals of long-lived assets and other expense (income), net in the period that the applicable proof of loss documentation is received. Proceeds from casualty insurance settlements that are expected to be less than the carrying value of damaged assets are recognized at the time the loss is incurred and recorded in losses (gains) on sales and disposals of long-lived assets and other expense (income), net.

We recognize reimbursements received for out-of-pocket expenses incurred as revenues and account for out-of-pocket expenses as direct costs.

Income Taxes

We are a Bermuda exempted company and are not subject to income taxes in Bermuda. Consequently, income taxes have been provided based on the tax laws and rates in effect in the countries where we operate and earn income. The income taxes in these jurisdictions vary substantially. Our effective tax rate for financial statement purposes will continue to fluctuate from year to year because our operations are conducted in different taxing jurisdictions.

We recognize increases to our tax reserves for uncertain tax positions along with interest and penalties as an increase to other long-term liabilities.

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For U.S. and other jurisdictional income tax purposes, we have net operating and other loss carryforwards that we are required to assess quarterly for potential valuation allowances. We consider the sufficiency of existing temporary differences and expected future earnings levels in determining the amount, if any, of valuation allowance required against such carryforwards and against deferred tax assets.

Nabors realizes an income tax benefit associated with certain awards issued under our stock plans. We recognize the benefits related to tax deductions up to the amount of the compensation expense recorded for the award in the consolidated statements of income (loss). Any excess tax benefit (i.e., tax deduction in excess of compensation expense) is reflected as an increase in capital in excess of par. Any shortfall is recorded as a reduction to capital in excess of par to the extent of our aggregate accumulated pool of windfall benefits, beyond which the shortfall would be recognized in the consolidated statements of income (loss).

Foreign Currency Translation

For certain of our foreign subsidiaries, such as those in Canada and Argentina, the local currency is the functional currency, and therefore translation gains or losses associated with foreign-denominated monetary accounts are accumulated in a separate section of the consolidated statements of changes in equity. For our other international subsidiaries, the U.S. dollar is the functional currency, and therefore local currency transaction gains and losses, arising from remeasurement of payables and receivables denominated in local currency, are included in our consolidated statements of income (loss).

Cash Flows

We treat the redemption price, including accrued original issue discount, on our convertible debt instruments as a financing activity for purposes of reporting cash flows in our consolidated statements of cash flows.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make certain estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosures of contingent assets and liabilities at the balance sheet date and the amounts of revenues and expenses recognized during the reporting period. Actual results could differ from such estimates. Areas where critical accounting estimates are made by management include:

- depreciation of property, plant and equipment;
- impairment of long-lived assets;

- impairment of goodwill and intangible assets;
- income taxes;
- litigation and self-insurance reserves; and
- fair value of assets acquired and liabilities assumed.

Recent Accounting Pronouncements

In January 2012, we adopted the revised provisions from the FASB ASU relating to the presentation of other comprehensive income (OCI). We removed our historical presentation of OCI from the statement of changes in equity and included a statement of other comprehensive income (loss) for all periods presented. The presentation of the OCI statement did not have an impact on our consolidated financial statements.

In January 2012, we adopted the revised provisions from the ASU relating to goodwill impairment tests. Companies are allowed to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. They are not required to calculate the fair value of a reporting unit unless they determine, based on their qualitative assessment, that it is more likely than not that the fair value is less than its

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carrying amount. The application of these provisions did not have a material impact on our consolidated financial statements.

Note 3 Impairments and Other Charges

The components of impairments and other charges is provided below:

	Year Ended December 31, 2012	2011 (In thousands)	2010
Provision for retirement of long-lived assets	$ 138,666	$ 98,072	$ 23,213
Intangible asset impairment	74,960		
Goodwill impairments	26,279		10,707
Impairment of long-lived assets	50,355		27,372
Provision for termination payment		100,000	
Total impairments and other charges	$ 290,260	$ 198,072	$ 61,292

Provision for retirement of long-lived assets

During 2012, we recorded a provision for retirement of long-lived assets in multiple operating segments, including $34.0 million in U.S. Lower 48 Land Drilling, $3.1 million in U.S. Offshore, $33.7 million in Canada, $16.5 million in International and $2.0 million in Other Rig Services, all from our Drilling & Rig Services business line. The retirements from this business line included mechanical rigs, a jackup rig and other assets that have become inoperable or functionally obsolete and that we do not believe could be returned to service without significant cost to refurbish.

Additionally in 2012, we recorded similar provisions for retirement of long-lived asset of $49.4 million in our Completion & Production Services business line. During 2012, we streamlined our operations and consolidated our U.S. Production Services and Completion Services into this business line, and retired some non-core assets. As we continue to streamline our lines of business, there could be future retirement or impairment charges, which could have a potential impact on our future operating results.

During 2011, we recorded a provision for retirement of long-lived assets totaling $98.1 million in multiple operating segments. This related to the decommissioning and retirement of one jackup rig, 116 land rigs, and a number of rigs and trucks. Our U.S. Lower 48 Land Drilling, International and U.S. Production Services operations recorded $63.2 million, $26.1 million and $8.9 million, respectively. These assets were deemed to be functionally or economically non-competitive for today s market and are being dismantled for parts and scrap.

During 2010, we recorded a provision for retirement of long-lived assets totaling $23.2 million related to the abandonment of certain rig components, comprised of engines, top-drive units, building modules and other equipment that had become obsolete or inoperable in our U.S. Lower 48 Land Drilling, U.S. Production Services and U.S. Offshore Contract Drilling operating segments.

A prolonged period of lower oil and natural gas prices and its potential impact on our utilization and dayrates could result in the recognition of future impairment charges to additional assets if future cash flow estimates, based upon information then available to management, indicate that the carrying value of those assets may not be recoverable.

Intangible asset impairment

During 2012, we recorded impairment of the Superior trade name totaling $75.0 million. The Superior trade name was initially classified as a ten-year intangible asset at the date of acquisition in September 2010. The impairment is a result of the decision to cease using the Superior trade name to reduce confusion in the marketplace and enhance the Nabors brand.

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Goodwill impairments

During 2012, we impaired the remaining goodwill balances of $7.3 million and $19.0 million of our U.S. Offshore and International operating segments, respectively. The impairments were deemed necessary due to the prolonged uncertainty of utilization of some of our rigs in the Gulf of Mexico as well as our international markets. We did not record any goodwill impairment in 2011.

During 2010, we recognized an impairment of approximately $10.7 million relating to our goodwill balance of our U.S. Offshore operating segment. The impairment charge was deemed necessary due to the uncertainty of utilization of some of our rigs as a result of changes in our customers plans for future drilling operations in the Gulf of Mexico. Many of our customers suspended drilling operations in the Gulf of Mexico, largely as a result of their inability to obtain government permits. Although the U.S. deepwater drilling moratorium was lifted, our customers continued to encounter delays in obtaining government permits.

These goodwill impairment charges stemmed from our annual impairment test on goodwill. A significantly prolonged period of lower oil and natural gas prices or changes in laws and regulations could adversely affect the demand for and prices of our services, which could result in future goodwill impairment charges for other reporting units due to the potential impact on our estimate of our future operating results. See Note 2 Summary of Significant Accounting Policies (included under the caption Goodwill) for amounts of goodwill related to each of our reporting units.

Impairments of Long-Lived Assets

During the fourth quarter of 2012, we determined that some of our coil-tubing rigs would not be fully utilized as forecasted, which resulted in a triggering event and required a year-end long-lived asset impairment test. Our year-end impairment test resulted in impairment charges of $17.4 million in our U.S. Lower 48 Land Drilling and $32.9 million in our Canada operations. We did not record any impairment of long-lived assets in 2011.

During 2010, we recognized $27.3 million in impairment charges related to some jackup rigs in our U.S. Offshore operating segment. These impairment charges stemmed from annual impairment tests on long-lived assets.

Provision for termination payment

During 2011, we recorded a provision for a contingent liability that existed on December 31, 2011 related to the change of our Chief Executive Officer that occurred in October 2011. This charge resulted from a potential termination payment to our former Chief Executive Officer, Eugene Isenberg, under the terms of his employment contract. Subsequent to December 31, 2011, Mr. Isenberg elected to forego triggering that payment and as a result, we did not owe or make the termination payment. During 2012, we made charitable contributions to benefit the needs of our employees and other community-based causes. We contributed one million Nabors common shares previously held by an affiliate to the Nabors Charitable Foundation, a 501(c)(3) organization, in support of this objective. We consider our former Chief Executive Officer to be a significant shareholder of the Company and, therefore, recorded these transactions as equity. During 2012, we recorded the release of the contingent liability, net of tax, through capital in excess of par as a forgiveness of liability from a beneficial owner. We recorded the donation of the treasury shares at their weighted-average cost, net of tax, through capital in excess of par.

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Note 4 Assets Held for Sale and Discontinued Operations

Assets Held for Sale

Assets held for sale included the following:

Assets Held for Sale	December 31, 2012		December 31, 2011	
	(In thousands)			
Oil and Gas	$	377,625	$	385,414
Other Rig Services		6,232		16,086
	$	383,857	$	401,500

Oil and Gas Properties

During 2010, we began marketing our oil and gas assets in Canada and Colombia, including our then 49.7% and 50.0% ownership interests in Remora and SMVP, respectively, and we reclassified the assets to assets held for sale. In 2011, we reclassified the carrying value of our wholly owned U.S. oil and gas assets to assets held for sale. The carrying value of our assets held for sale as of December 31, 2012 and 2011 represents the lower of carring value or fair value less costs to sell. We continue to market these properties at prices that are reasonable compared to current fair value. Also, as of December 31, 2012, we have deferred tax assets of approximately $106 million, which are included in long-term deferred income taxes in our consolidated balance sheet, associated with our oil and gas operations in Canada.

We have contracts with pipeline companies to pay specified fees based on committed volumes for gas transport and processing. At December 31, 2012, our undiscounted contractual commitments for such contracts approximate $339.6 million. At December 31, 2012, we have liabilities of $206 million, $69 million of which are classified as current and are included in accrued liabilities. These amounts represent our best estimate of the fair value of the excess capacity of the pipeline commitments calculated using a discounted cash flow model (a Level 3 measurement), when considering our disposal plan, current production levels, natural gas prices and expected utilization of the pipeline over the remaining contractual term. Decreases in actual production or natural gas prices could result in future charges related to excess capacity of the pipeline.

During 2011, we evaluated production levels, natural gas prices and market conditions, and determined our production flowing to pipelines and processing plants did not meet the volumes required under the contracts. Accordingly at December 31, 2011, we recorded liabilities of $125 million, $71 million was classified as current and included in accrued liabilities.

In 2011, we sold some of our wholly owned oil and gas assets in Colombia to an unrelated third party. We received proceeds of $89.2 million from this sale and recognized a gain of approximately $39.6 million. Additionally during 2011, Remora completed sales of its oil and gas assets and made cash distributions to us in the amount of $143.0 million. At December 31, 2012 and 2011, our oil and gas assets held for sale included a receivable of approximately $4.1 million and $13.7 million, respectively, representing a final distribution to us upon dissolution of the joint venture.

In 2011, we sold our 25% working interest in the Cat Canyon and West Cat Canyon fields in Santa Barbara County, California to an unrelated party and received proceeds of approximately $71.6 million. Also, the equity owners of SMVP dissolved the partnership and a proportionate share of the assets and liabilities were conveyed to us in exchange for our ownership interest.

In 2012, we sold our remaining wholly owned oil and gas business in Colombia and sold some of our U.S. wholly owned oil and gas assets in the Fayetteville Shale, Floyd Shale, and Barnett Shale areas as well as properties primarily in Texas, Louisiana and Utah. We received cumulative cash receipts of $104.5 million from these third parties during 2012.

At December 31, 2012, our assets held for sale included suspended wells that have capitalized costs for more than one year. Specifically, on the north slope of Alaska, seven wells, including two drilled in 2007, one drilled in 2008, two drilled in 2010 and two drilled in 2012, were suspended with total capitalized costs of $70.2 million. Further drilling is needed over the area to determine if the discovery holds sufficient quantities of reserves to justify future investment of infrastructure.

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Other Rig Services

During 2011, we determined that one of our Canadian subsidiaries that provides logistic services for onshore drilling using helicopter and fixed-wing aircraft met the accounting criteria of assets held for sale. Based on quoted market prices, the carrying value of these assets at December 31, 2012 and 2011 represent fair value less costs to sell.

Discontinued Operations

The operating results from the assets discussed above for all periods presented are retroactively presented and accounted for as discontinued operations in the accompanying audited consolidated statements of income (loss) and the respective accompanying notes to the consolidated financial statements. Our condensed statements of income (loss) from discontinued operations for each operating segment were as follows:

	Year Ended December 31, 2012	2011 (In thousands)	2010
Operating revenues and Earnings (losses) from unconsolidated affiliates			
Oil and Gas	$ 27,363	$ 125,654(1)	$ 37,615
Other Rig Services	$ 25,813	$ 29,713	$ 29,739
Income (loss) from Oil and Gas discontinued operations:			
Income (loss) from discontinued operations	$ (3,954)	$ 18,660	$ (26,139)
Impairment charges or other gains and losses on sale of wholly owned assets	(106,100)(2)	(255,046)(3)	(192,179)(4)
Less: income tax expense (benefit)	(44,021)	(98,181)	(62,028)
Income (loss) from Oil and Gas discontinued operations, net of tax	$ (66,033)	$ (91,394)	$ (156,290)
Income (loss) from Other Rig Services discontinued operations:			
Income (loss) from discontinued operations	$ (2,080)	$ (210)	$ 1,059
Impairment and gains and losses on long-lived assets	(9,082)(5)	(7,853)(5)	(7,460)
Less: income tax expense (benefit)	(2,795)	(2,017)	(1,601)
Income (loss) from Other Rig Services discontinued operations, net of tax	$ (8,367)	$ (6,046)	$ (4,800)

Oil and Gas

(1) Includes approximately $83 million of equity in earnings during 2011 for our proportionate share of Remora s net income, inclusive of the gains recognized for asset sales during 2011.

(2) Includes adjustments during 2012 to increase our pipeline contractual commitments by $128.1 million and other gains and losses related to the sale of our wholly owned oil and gas-centered assets.

(3) Includes impairments during 2011 of $255.0 million to write down the carrying value of our wholly owned oil and gas-centered assets, including $27.2 million related to an oil and gas financing receivable that was deemed uncollectible.

(4) Includes impairments during 2010 of $192.2 million related to our wholly owned oil and gas assets. Of this total, $137.8 million represented writedowns to the carrying value of some acreage in the United States, which we did not have future plans to develop due to sustained low natural gas prices, and certain exploratory wells in Colombia, which we determined were uneconomical to develop in the foreseeable future. The remaining $54.3 million related to impairment of an oil and gas financing receivable and was determined using discounted cash flow models, a Level 3 measurement, and involved assumptions based on estimated cash flows for proved and probable reserves, undeveloped acreage value, and current and expected natural gas prices.

Other Rig Services

(5) Includes $7.8 million and $7.9 million, respectively, of impairment (a Level 3 measurement) in 2012 and 2011 to our aircraft and logistics assets as a result of the continued downturn in the oil and gas industry in Canada.

Additional discussion of our policy pertaining to the calculations of our annual impairment tests, including any impairment to goodwill, is set forth in Note 2 Summary of Significant Accounting Policies. A further protraction of lower commodity prices or an inability to sell these assets in a timely manner could result in recognition of future impairment charges.

Note 5 Acquisitions

2011 Acquisitions

In July 2011, we paid $65 million in cash to acquire the remaining 50 percent equity interest of Peak, making it a wholly owned subsidiary on this date. Peak operates in Alaska, providing construction and rig moving services in icy conditions as well as light and heavy-duty moving, hauling and maintenance services. Previously, we held a 50 percent equity interest with a carrying value of $38.1 million that we had accounted for as an equity method investment. As a result of the acquisition, we consolidated the assets and liabilities of Peak during the third quarter of 2011 based on their respective fair values, in accordance with Topic 805 Business Combinations. The excess of the estimated fair value of the assets and liabilities over the net carrying value of our previously held equity interest resulted in a gain of $13.1 million and is reflected in losses (gains) on sales and disposals of long-lived assets and other expense (income) for 2011. The excess of the purchase price over the fair values was $8.0 million and was recorded as goodwill.

2010 Acquisitions

In September 2010, we acquired through a tender offer and merger all of the outstanding common stock of NCPS (formerly, Superior) at a price per share equal to $22.12, for a cash purchase price of approximately $681.3 million. The effects of this acquisition and the operating results are included in the accompanying consolidated financial statements for the period subsequent to the effective date of the acquisition. Superior contributed revenues of $1.2 billion to our consolidated revenues for 2011.

As part of this acquisition, we recognized $7.0 million of acquisition-related transaction costs in losses (gains) on sales and disposals of long-lived assets and other expense (income) for the year ended December 31, 2010. The acquisition-related transaction costs consisted primarily of investment banking fees and legal and accounting costs. The acquisition enhanced our well-servicing and workover operations.

The following table provides the allocation of the purchase price as of the acquisition date. The purchase price was allocated to the net tangible and intangible assets acquired and liabilities assumed based on fair value. The excess of the purchase price over such fair values was recorded as goodwill.

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Estimated Fair Value
(In thousands)

Assets:		
Cash and cash equivalents	$	1,045
Accounts receivable		143,842
Inventory		33,963
Other current assets		7,612
Property, plant and equipment		415,000
Intangible assets		131,811
Goodwill		334,992
Other long-term assets		14,726
Total assets	$	1,082,991
Liabilities:		
Current liabilities	$	78,277
Deferred income taxes		119,201
Long-term debt		124,792
Other long-term liabilities		10,258
Total liabilities		332,528
Preferred stock		69,188
Net assets acquired	$	681,275

Intangible assets

We identified other intangible assets associated with fracturing and fluid logistics services, including trade name, technology, employment contracts and non-compete agreements and customer relationships. The amortization of the intangible assets is calculated on a straight-line basis, which estimates the consumption of economic benefits. The following table summarizes the intangible assets recognized at the acquisition date, the monthly amortization expense as well as their estimated useful lives:

		Estimated Fair Value		**Monthly Amortization (In thousands)**	**Estimated Useful Life**
Superior trade name	$	88,767	$	740	10 years
Technology		5,294		88	5 years
Employment contracts and non-compete agreements		675		33	1-3 years
Customer relationships		37,075		308	10 years
Total identifable intangible assets	$	131,811	$	1,169	

During 2012, we ceased using the Superior trade name and recorded an impairment of approximately $75.0 million to remove the remaining balance of the related intangible asset. See Note 3 Impairment and Other Charges for additional information.

Goodwill

Goodwill of $335.0 million arising from the acquisition consisted largely of the expected synergies and economies of scale from combining the operations of Nabors and the former Superior. We have allocated the goodwill to our Completion Services operating segment. See Note 2 Summary of Significant Account Policies for additional information.

Long-term debt

Long-term debt included a secured revolving credit facility and second lien notes at the acquisition date. As of December 31, 2010, all amounts outstanding had been repaid.

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Other acquisitions

In December 2010, we purchased the business of Energy Contractors for a total cash purchase price of $53.4 million. The assets were comprised of vehicles and rig equipment and have been included in our U.S. Production Services operating segment. The purchase price was allocated to the net tangible and intangible assets acquired based on their fair value as of December 31, 2010. The excess of the purchase price over the fair values of the assets acquired was recorded as goodwill in the amount of $4.2 million.

Note 6 Cash and Cash Equivalents and Short-term Investments

Our cash and cash equivalents and short-term investments consisted of the following:

	December 31, 2012	December 31, 2011
	(In thousands)	
Cash and cash equivalents	$ 524,922	$ 398,575
Short-term investments:		
Trading equity securities	$ 52,705	$ 11,600
Available-for-sale equity securities	174,610	71,433
Available-for-sale debt securities	25,967	57,881
Total short-term investments	$ 253,282	$ 140,914

Certain information related to our cash and cash equivalents and short-term investments follows:

	December 31, 2012			December 31, 2011		
	Fair Value	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Fair Value	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses
	(In thousands)					
Cash and cash equivalents	$ 524,922	$	$	$ 398,575	$	$
Short-term investments:						
Trading equity securities	52,705	46,981		11,600	5,876	
Available-for-sale equity securities	174,610	137,282	(1,030)	71,433	33,075	
Available-for-sale debt securities:						
Commercial paper and CDs	206			1,230		
Corporate debt securities	23,399	1,870		51,300	22,494	(2,095)
Mortgage-backed debt securities	244	15		309	10	
Mortgage-CMO debt securities	523	10	(3)	2,547	13	(15)
Asset-backed debt securities	1,595	28	(192)	2,495		(238)

Total available-for-sale debt securities	25,967	1,923	(195)	57,881	22,517	(2,348)
Total available-for-sale securities	200,577	139,205	(1,225)	129,314	55,592	(2,348)
Total short-term investments	253,282	186,186	(1,225)	140,914	61,468	(2,348)
Total cash, cash equivalents and short-term investments	$ 778,204	$ 186,186	$ (1,225)	$ 539,489	$ 61,468	$ (2,348)

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Certain information related to the gross unrealized losses of our cash and cash equivalents and short-term investments follows:

	As of December 31, 2012			
	Less Than 12 Months		More Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	(In thousands)			
Available-for-sale equity securities	$ 17,865	$ 1,030	$	$
Available-for-sale debt securities: (1)				
Corporate debt securities				
Mortgage-CMO debt securities	315	1	35	2
Asset-backed debt securities			500	192
Total available-for-sale debt securities	315	1	535	194
Total	$ 18,180	$ 1,031	$ 535	$ 194

(1) Our unrealized losses on available-for-sale debt securities held for more than one year are comprised of various types of securities. Each of these securities have a rating ranging from A to AAA from Standard & Poor s and ranging from A2 to Aaa from Moody s Investors Servic and is considered of high credit quality. In each case, we do not intend to sell these investments, and it is less likely than not that we will be required to sell them to satisfy our own cash flow and working capital requirements. We believe that we will be able to collect all amounts due according to the contractual terms of each investment and, therefore, do not consider the decline in value of these investments to be other-than-temporary at December 31, 2012.

The estimated fair values of our corporate, mortgage-backed, mortgage-CMO and asset-backed debt securities at December 31, 2012, classified by time to contractual maturity, are shown below. Expected maturities differ from contractual maturities because the issuers of the securities may have the right to repay obligations without prepayment penalties and we may elect to sell the securities prior to the contractual maturity date.

	Estimated Fair Value December 31, 2012 (In thousands)
Debt securities:	
Due in one year or less	$ 206
Due after one year through five years	19,225
Due in more than five years	6,536
Total debt securities	$ 25,967

Certain information regarding our debt and equity securities is presented below:

	Year Ended December 31,		
	2012	2011	2010
	(In thousands)		
Available-for-sale			
Proceeds from sales and maturities	$ 24,010	$ 12,672	$ 13,062

Realized gains (losses), net	$	13,405	$	3,036	$	1,694

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Note 7 Fair Value Measurements

As defined in the ASC, fair value is the price that would be received upon sale of an asset or paid upon transfer of a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market-corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best information available. Accordingly, we employ valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The use of unobservable inputs is intended to allow for fair value determinations in situations where there is little, if any, market activity for the asset or liability at the measurement date. We are able to classify fair value balances utilizing a fair value hierarchy based on the observability of those inputs. Under the fair value hierarchy:

- Level 1 measurements include unadjusted quoted market prices for identical assets or liabilities in an active market;

- Level 2 measurements include quoted market prices for identical assets or liabilities in an active market that have been adjusted for items such as effects of restrictions for transferability and those that are not quoted but are observable through corroboration with observable market data, including quoted market prices for similar assets; and

- Level 3 measurements include those that are unobservable and of a subjective nature.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities that are accounted for at fair value on a recurring basis as of December 31, 2012. Our debt securities could transfer into or out of a Level 1 or 2 measure depending on the availability of independent and current pricing at the end of each quarter. During 2012, there were no transfers of our financial assets between Level 1 and Level 2 measures. Our financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

	Fair Value as of December 31, 2012			
	Level 1	**Level 2**	**Level 3**	**Total**
	(In thousands)			
Assets:				
Short-term investments:				
Available-for-sale equity securities from energy industry	$ 163,924	$ 10,686	$	$ 174,610
Available-for-sale debt securities:				
Commercial paper and CDs	206			206
Corporate debt securities		23,399		23,399
Mortgage-backed debt securities		244		244
Mortgage-CMO debt securities		523		523
Asset-backed debt securities	1,595			1,595
Trading equity securities from energy industry	52,705			52,705
Total short-term investments	$ 218,430	$ 34,852	$	$ 253,282

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Nonrecurring Fair Value Measurements

Fair value measurements were applied with respect to our nonfinancial assets and liabilities measured on a nonrecurring basis, which would consist of measurements primarily to assets held for sale, goodwill, intangible assets and other long-lived assets, assets acquired and liabilities assumed in a business combination, asset retirement obligations and our pipeline contractual commitment.

Fair Value of Financial Instruments

The fair value of our financial instruments has been estimated in accordance with GAAP. The fair value of our long-term debt and subsidiary preferred stock is estimated based on quoted market prices or prices quoted from third-party financial institutions. The carrying and fair values of these liabilities were as follows:

	As of December 31,			
	2012		2011	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
6.15% senior notes due February 2018	$ 968,708	$ 1,164,813	$ 967,490	$ 1,113,986
9.25% senior notes due January 2019	1,125,000	1,492,819	1,125,000	1,419,514
5.00% senior notes due September 2020	697,648	770,707	697,343	734,475
4.625% senior notes due September 2021	697,907	755,517	697,667	708,176
5.375% senior notes due August 2012			274,604	281,188
Subsidiary preferred stock	69,188	68,625	69,188	68,625
Revolving credit facilities	890,000	890,000	860,000	860,000
Other	437	437	1,712	1,712
	$ 4,448,888	$ 5,142,918	$ 4,693,004	$ 5,187,676

The fair values of our cash equivalents, trade receivables and trade payables approximate their carrying values due to the short-term nature of these instruments.

As of December 31, 2012, our short-term investments were carried at fair market value and included $200.6 million and $52.7 million in securities classified as available-for-sale and trading, respectively. As of December 31, 2011, our short-term investments were carried at fair market value and included $129.3 million and $11.6 million in securities classified as available-for-sale and trading, respectively.

Note 8 Share-Based Compensation

Total share-based compensation expense, which includes both stock options and restricted stock, totaled $18.2 million, $21.2 million and $13.7 million for 2012, 2011 and 2010, respectively. Compensation expense related to awards of restricted stock totaled $14.1 million, $13.4 million and $10.5 million for 2012, 2011 and 2010, respectively, and is included in direct costs and general and administrative expenses in our consolidated statements of income (loss). Share-based compensation expense has been allocated to our various operating segments. See Note 22 Segment Information.

The cash flows resulting from tax deductions in excess of the compensation cost recognized for share-based awards (excess tax benefits) are classified as financing cash flows. The actual tax benefit realized from share-based awards during the years ended December 31, 2012, 2011 and 2010 was $.1 million, $.2 million and $.1 million, respectively.

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Stock Option Plans

As of December 31, 2012, we had several stock plans under which options to purchase our common shares could be granted to key officers, directors and managerial employees of Nabors and its subsidiaries. Options granted under the plans generally are at prices equal to the fair market value of the shares on the date of the grant. Options granted under the plans generally are exercisable in varying cumulative periodic installments after one year. In the case of certain key executives, options granted may vest immediately on the grant date. Options granted under the plans cannot be exercised more than ten years from the date of grant. Options to purchase 14.3 million and 15.5 million Nabors common shares remained available for grant as of December 31, 2012 and 2011, respectively. Of the common shares available for grant as of December 31, 2012, approximately 14.3 million of these shares are also available for issuance in the form of restricted shares.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option-pricing model which uses assumptions for the risk-free interest rate, volatility, dividend yield and the expected term of the options. The risk-free interest rate is based on the U.S. Treasury yield curve in effect at the time of grant for a period equal to the expected term of the option. Expected volatilities are based on implied volatilities from traded options on Nabors common shares, historical volatility of Nabors common shares, and other factors. We do not assume any dividend yield, since we do not pay dividends. We use historical data to estimate the expected term of the options and employee terminations within the option-pricing model; separate groups of employees that have similar historical exercise behavior are considered separately for valuation purposes. The expected term of the options represents the period of time that the options granted are expected to be outstanding.

We also consider an estimated forfeiture rate for these option awards, and we recognize compensation cost only for those shares that are expected to vest, on a straight-line basis over the requisite service period of the award, which is generally the vesting term of three to five years. The forfeiture rate is based on historical experience. Estimated forfeitures have been adjusted to reflect actual forfeitures during 2012.

Stock option transactions under our various stock-based employee compensation plans are presented below:

Options	**Shares**	**Weighted-Average Exercise Price**	**Weighted-Average Remaining Contractual Term**	**Aggregate Intrinsic Value**
		(In thousands, except exercise price)		
Options outstanding as of December 31, 2011	27,870	$ 18.94		
Granted	658	21.82		
Exercised	(1,151)	12.42		
Surrendered (1)	(4,563)	13.52		
Forfeited	(350)	15.07		
Options outstanding as of December 31, 2012	22,464	$ 20.53	3.64 years	$ 36,075
Options exercisable as of December 31, 2012	20,837	$ 20.99	3.33 years	$ 31,429

(1) Represents unexercised vested stock options that were surrendered by key officers, directors and employees, to satisfy the option exercise price and related income taxes. See related discussion at Note 14 Common Shares.

Of the options outstanding, 20.8 million, 24.9 million and 24.9 million were exercisable at weighted-average exercise prices of $20.99, $19.83 and $20.19, as of December 31, 2012, 2011 and 2010, respectively.

During the years ended December 31, 2012, 2011 and 2010, respectively, we awarded options vesting over periods up to four years to purchase 658,061, 930,753 and 32,115 of our common shares to our employees, executive officers and directors.

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The fair value of stock options granted during 2012, 2011 and 2010 was calculated using the Black-Scholes option pricing model and the following weighted-average assumptions:

	Year Ended December 31, 2012	2011	2010
Weighted average fair value of options granted	$ 9.40	$ 6.24	$ 6.62
Weighted average risk free interest rate	0.63%	0.65%	1.49%
Dividend yield	0%	0%	0%
Volatility (1)	55.74%	51.09%	41.44%
Expected life	4.0 years	4.0 years	4.0 years

(1) Expected volatilities are based on implied volatilities from publicly traded options to purchase Nabors common shares, historical volatility of Nabors common shares and other factors.

A summary of our unvested stock options as of December 31, 2012, and the changes during the year then ended is presented below:

Unvested Stock Options	Outstanding	Weighted-Average Grant-Date Fair Value
	(In thousands, except fair value)	
Unvested as of December 31, 2011	2,900	$ 3.88
Granted	658	$ 9.40
Vested	(1,773)	$ 4.44
Forfeited	(159)	$ 2.81
Unvested as of December 31, 2012	1,626	$ 5.62

The total intrinsic value of options exercised during the years ended December 31, 2012, 2011 and 2010 was $23.7 million, $18.3 million and $6.9 million, respectively. The total fair value of options that vested during the years ended December 31, 2012, 2011 and 2010 was $7.9 million, $5.2 million and $5.6 million, respectively.

As of December 31, 2012, there was $5.9 million of total future compensation cost related to unvested options that are expected to vest. That cost is expected to be recognized over a weighted-average period less than two years.

Restricted Stock and Restricted Stock Units

Our stock plans allow grants of restricted stock. Restricted stock is issued on the grant date, but cannot be sold or transferred. Restricted stock vests in varying periodic installments ranging up to five years.

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A summary of our restricted stock as of December 31, 2012, and the changes during the year then ended, is presented below:

Restricted stock	Outstanding		Weighted-Average Grant-Date Fair Value
	(In thousands, except fair value)		
Unvested as of December 31, 2011	1,556	$	26.07
Granted	944	$	20.69
Vested	(503)	$	25.94
Forfeited	(216)	$	24.66
Unvested as of December 31, 2012	1,781	$	23.42

During 2012 and 2011, we awarded 944,015 and 1,096,379 shares of restricted stock, respectively, to our employees and directors. These awards had an aggregate value at their date of grant of $19.5 million and $30.0 million, respectively, and were scheduled to vest over a period of up to four years. The fair value of restricted stock that vested during the years ended December 31, 2012, 2011 and 2010 was $9.7 million, $21.4 million and $26.7 million, respectively.

As of December 31, 2012, there was $30.6 million of total future compensation cost related to unvested restricted stock awards that are expected to vest. That cost is expected to be recognized over a weighted-average period of approximately one year.

Note 9 Property, Plant and Equipment

The major components of our property, plant and equipment are as follows:

	December 31,			
		2012		2011
	(In thousands)			
Land	$	49,965	$	22,120
Buildings		154,878		132,753
Drilling, workover and well-servicing rigs, and related equipment		12,364,021		11,150,927
Marine transportation and supply vessels		14,054		14,023
Oilfield hauling and mobile equipment		1,313,339		1,171,930
Other machinery and equipment		176,468		248,938
Oil and gas properties				42,033
Construction-in-process (1)		363,537		815,987
	$	14,436,262	$	13,598,711
Less: accumulated depreciation and amortization		(5,724,174)		(4,928,781)
Less: accumulated depletion				(39,984)
	$	8,712,088	$	8,627,897

(1) Relates primarily to amounts capitalized for new or substantially new drilling, workover and well-servicing rigs that were under construction and had not yet been placed in service as of December 31, 2012 or 2011.

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Repair and maintenance expense included in direct costs in our consolidated statements of income (loss) totaled $563.5 million, $586.4 million and $382.5 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Interest costs of $19.4 million, $24.0 million and $12.4 million were capitalized during the years ended December 31, 2012, 2011 and 2010, respectively.

Information relating to suspended wells that have capitalized costs for more than one year at December 31, 2012 is located at Note 4 Assets Held for Sale and Discontinued Operations.

Note 10 Investments in Unconsolidated Affiliates

Our principal investment in unconsolidated affiliates accounted for using the equity method include drilling and workover operations located in Saudi Arabia (51% ownership). This unconsolidated affiliate is integral to our operations. See Note 17 Related-Party Transactions for additional information. On December 15, 2012, we sold our equity interests in NFR Energy and at December 31, 2012 have no active oil and gas joint ventures.

As of December 31, 2012 and 2011, our consolidated balance sheets reflect our investments in unconsolidated affiliates accounted for using the equity method totaling $61.7 million and $371.0 million, respectively. Assets held for sale include an investment in unconsolidated affiliates accounted for using the equity method and represents a receivable from dissolution of an oil and gas joint venture in 2011, which totaled $4.1 million and $13.7 million at December 31, 2012 and 2011, respectively.

Combined condensed financial data for investments in unconsolidated affiliates, including assets classified as held for sale, are summarized as follows:

	December 31,			
	2012		2011	
	(In thousands)			
Current assets	$	174,977	$	311,972
Long-term assets	$	161,207	$	1,728,399
Current liabilities	$	195,504	$	275,171
Long-term liabilities	$	3,389	$	800,444

	Year Ended December 31,					
	2012		2011		2010	
	(In thousands)					
Gross revenues	$	758,140	$	832,774	$	901,742
Gross margin	$	207,813	$	278,019	$	241,831
Net income (loss)	$	(619,591)	$	270,161	$	48,426
Nabors earnings (losses) from unconsolidated affiliates (1)	$	(301,320)	$	56,647	$	33,267

(1) Nabors earnings (losses) from unconsolidated affiliates included in discontinued operations, net of tax was $76.5 million and $(10.6) million, respectively, for the years ended December 31, 2011 and 2010.

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Note 11 Financial Instruments and Risk Concentration

We may be exposed to certain market risks arising from the use of financial instruments in the ordinary course of business. These risks arise primarily as a result of potential changes in the fair market value of financial instruments that would result from adverse fluctuations in foreign currency exchange rates, credit risk, interest rates, and marketable and non-marketable security prices as discussed below.

Foreign Currency Risk

We operate in a number of international areas and are involved in transactions denominated in currencies other than U.S. dollars, which exposes us to foreign exchange rate risk or foreign currency devaluation risk. The most significant exposures arise in connection with our operations in Venezuela and Canada, which usually are substantially unhedged.

At various times, we utilize local currency borrowings (foreign-currency-denominated debt), the payment structure of customer contracts and foreign exchange contracts to selectively hedge our exposure to exchange rate fluctuations in connection with monetary assets, liabilities, cash flows and commitments denominated in certain foreign currencies. A foreign exchange contract is a foreign currency transaction, defined as an agreement to exchange different currencies at a given future date and at a specified rate.

Credit Risk

Our financial instruments that potentially subject us to concentrations of credit risk consist primarily of cash equivalents, short-term and long-term investments and accounts receivable. Cash equivalents such as deposits and temporary cash investments are held by major banks or investment firms. Our short-term and long-term investments are managed within established guidelines that limit the amounts that may be invested with any one issuer and provide guidance as to issuer credit quality. We believe that the credit risk in our cash and investment portfolio is minimized as a result of the mix of our investments. In addition, our trade receivables are with a variety of U.S., international and foreign-country national oil and gas companies. Management considers this credit risk to be limited due to the financial resources of these companies. We perform ongoing credit evaluations of our customers, and we generally do not require material collateral. We do occasionally require prepayment of amounts from customers whose creditworthiness is in question prior to providing services to them. We maintain reserves for potential credit losses, and these losses historically have been within management s expectations.

Interest Rate and Marketable and Non-marketable Security Price Risk

Our financial instruments that are potentially sensitive to changes in interest rates include our 6.15%, 9.25%, 5.0% and 4.625% senior notes, our investments in debt securities (including corporate, asset-backed, mortgage-backed debt and mortgage-CMO debt securities) and our investments in overseas funds that invest primarily in a variety of public and private U.S. and non-U.S. securities (including asset-backed and mortgage-backed securities, global structured-asset securitizations, whole-loan mortgages, and participations in whole loans and whole-loan mortgages), which are classified as long-term investments.

We may utilize derivative financial instruments that are intended to manage our exposure to interest rate risks. The use of derivative financial instruments could expose us to further credit risk and market risk. Credit risk in this context is the failure of a counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty would owe us, which can create credit risk for us. When the fair value of a derivative contract is negative, we would owe the counterparty, and therefore, we would not be exposed to credit risk. We attempt to minimize credit risk in derivative instruments by entering into transactions with major financial institutions that have a significant asset base. Market risk related to derivatives is the adverse effect on the value of a financial instrument that results from changes in interest rates. We try to manage market risk associated with interest-rate contracts by establishing and monitoring parameters that limit the type and degree of market risk that we undertake.

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Note 12 Debt

	As of December 31, 2012	As of December 31, 2011
	(In thousands)	
6.15% senior notes due February 2018	$ 968,708	$ 967,490
9.25% senior notes due January 2019	1,125,000	1,125,000
5.00% senior notes due September 2020	697,648	697,343
4.625% senior notes due September 2021	697,907	697,667
5.375% senior notes due August 2012		274,604
Revolving credit facilities	890,000	860,000
Other	437	1,712
	$ 4,379,700	$ 4,623,816
Less: current portion	364	275,326
	$ 4,379,336	$ 4,348,490

As of December 31, 2012, the maturities of our primary debt for each of the five years after 2012 and thereafter are as follows:

	Paid at Maturity (In thousands)
2013	$
2014	
2015	
2016	
2017	890,000(1)
Thereafter	3,500,000(2)
	$ 4,390,000

(1) Represents amounts drawn on our revolving credit facility, which expires November 2017.

(2) Represents our 6.15% senior notes due February 2018, 9.25% senior notes due January 2019, 5.0% senior notes due September 2020 and 4.625% senior notes due September 2021.

6.15% Senior Notes Due February 2018

On February 20, 2008, Nabors Delaware completed a private placement of $575 million aggregate principal amount of 6.15% senior notes due 2018 with registration rights, which are unsecured and are fully and unconditionally guaranteed by us. On July 22, 2008, Nabors Delaware completed an additional private placement under the same indenture of $400 million aggregate principal amount of 6.15% senior notes due 2018, also with registration rights and fully and unconditionally guaranteed by us. These new notes are subject to the same rates, terms and conditions and together will be treated as a single class of debt securities under the indenture (together $975 million 6.15% senior notes due 2018). The issue of notes was resold by the initial purchasers to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain investors outside of the United States pursuant to Regulation S under the Securities Act. The notes bear interest at a rate of 6.15% per year, payable semi-annually on February 15 and August 15 and will mature on February 15, 2018.

The notes are unsecured and are effectively junior in right of payment to any of Nabors Delaware s future secured debt. The senior notes rank equally with any of Nabors Delaware s other existing and future unsubordinated debt and are senior in right of payment to any of Nabors Delaware s future senior subordinated debt. Our guarantee of the senior notes is unsecured and ranks equal in right of payment to all of our unsecured and unsubordinated indebtedness from time to time outstanding. The notes are subject to redemption by Nabors

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Delaware, in whole or in part, at any time at a redemption price equal to the greater of (i) 100% of the principal amount of the notes then outstanding to be redeemed; or (ii) the sum of the present values of the remaining scheduled payments of principal and interest, determined in the manner set forth in the indenture. In the event of a change in control triggering event, as defined in the indenture, the holders of notes may require Nabors Delaware to purchase all or any part of each note in cash equal to 101% of the principal amount plus accrued and unpaid interest, if any, to the date of purchase, except to the extent Nabors Delaware has exercised its right to redeem the notes.

9.25% Senior Notes Due January 2019

On January 12, 2009, Nabors Delaware completed a private placement of $1.125 billion aggregate principal amount of 9.25% senior notes due 2019 with registration rights, which are unsecured and are fully and unconditionally guaranteed by us. The notes were resold by the initial purchasers to qualified institutional buyers under Rule 144A and to certain investors outside of the United States under Regulation S. The notes bear interest at a rate of 9.25% per year, payable semi-annually on January 15 and July 15 and will mature on January 15, 2019.

The notes are unsecured and are junior in right of payment to any of Nabors Delaware s future secured debt. The notes rank equally with any of Nabors Delaware s other existing and future unsubordinated debt and are senior in right of payment to any of Nabors Delaware s future senior subordinated debt. Our guarantee of the notes is unsecured and ranks equal in right of payment to all of our unsecured and unsubordinated indebtedness from time to time outstanding. The notes are subject to redemption by Nabors Delaware, in whole or in part, at any time at a redemption price equal to the greater of (i) 100% of the principal amount of the notes then outstanding to be redeemed; or (ii) the sum of the present values of the remaining scheduled payments of principal and interest, determined in the manner set forth in the applicable indenture. In the event of a change in control triggering event, as defined in the indenture, the holders of notes may require Nabors Delaware to purchase all or any part of each note in cash equal to 101% of the principal amount plus accrued and unpaid interest, if any, to the date of purchase, except to the extent Nabors Delaware has exercised its right to redeem the notes.

5.0% Senior Notes Due September 2020

On September 14, 2010, Nabors Delaware completed a private placement of $700 million aggregate principal amount of 5.0% senior notes due 2020, which are unsecured and fully and unconditionally guaranteed by us. The notes are subject to registration rights. The notes were resold by the initial purchasers to qualified institutional buyers under Rule 144A and to certain investors outside of the United States under Regulation S. The notes pay interest semi-annually on March 15 and September 15 and will mature on September 15, 2020.

The notes rank equal in right of payment to all of Nabors Delaware s existing and future unsubordinated indebtedness, and senior in right of payment to all of Nabors Delaware s existing and future senior subordinated and subordinated indebtedness. Our guarantee of the notes is unsecured and an unsubordinated obligation and ranks equal in right of payments to all of our unsecured and unsubordinated indebtedness from time to time outstanding. In the event of a change of control triggering event, as defined in the indenture, the holders of the notes may require Nabors Delaware to purchase all or a portion of the notes at a purchase price equal to 101% of their principal amount, plus accrued and unpaid interest, if any. The notes are redeemable in whole or in part at any time at the option of Nabors Delaware at a redemption price, plus accrued and unpaid interest, as specified in the indenture. Nabors Delaware used a portion of the proceeds to repay the borrowing under a revolving credit facility incurred to fund our acquisition in September 2010.

Prior to the issuance of the notes during September 2010, we entered into a Treasury rate lock with a total notional amount of $500 million to hedge the risk of changes in semi-annual interest payments. We designated the Treasury rate lock derivative as a cash flow hedge and upon settlement paid $5.7 million, due to the change in the fair value of the derivative. The loss was recognized as a component of accumulated other comprehensive income in our consolidated statement of changes in equity and is being amortized as additional interest expense over the life of the notes. There was no ineffectiveness associated with this hedge during 2010.

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4.625% Senior Notes Due September 2021

On August 23, 2011, Nabors Delaware completed a private placement of $700 million aggregate principal amount of 4.625% senior notes due 2021, which are unsecured and fully and unconditionally guaranteed by us. The notes have registration rights. The notes were resold by the initial purchasers to qualified institutional buyers under Rule 144A and to certain investors outside of the United States under Regulation S. The notes pay interest semi-annually on March 15 and September 15 and will mature on September 15, 2021.

The notes rank equal in right of payment to all of Nabors Delaware s existing and future unsubordinated indebtedness, and senior in right of payment to all of Nabors Delaware s existing and future senior subordinated and subordinated indebtedness. Our guarantee of the notes is unsecured and an unsubordinated obligation and ranks equal in right of payments to all of our unsecured and unsubordinated indebtedness from time to time outstanding. In the event of a change of control triggering event, as defined in the indenture, the holders of the notes may require Nabors Delaware to purchase all or a portion of the notes at a purchase price equal to 101% of their principal amount, plus accrued and unpaid interest, if any. The notes are redeemable in whole or in part at any time at the option of Nabors Delaware at a redemption price, plus accrued and unpaid interest, as specified in the indenture. Nabors Delaware used a portion of the proceeds to pay back borrowings on our revolving credit facilities and for other general corporate purposes.

5.375% Senior Notes Due August 2012

During August 2012, we paid $282.4 million at maturity of Nabors Delaware s 5.375% senior notes, representing principal of $275.0 million and accrued interest of $7.4 million. We used cash on hand and $270 million from revolving credit facilities to pay this obligation.

Senior Exchangeable Notes

On May 16, 2011, the remaining aggregate principal amount of $1.4 billion of our 0.94% senior exchangeable notes matured, and we redeemed them with $1.2 billion of borrowings under our revolving credit facilities and available cash. During 2011 and 2010, we recognized pre-tax gains (losses) of $(.1) million and $(7.0) million, respectively, all of which are included in losses (gains) on sales and disposals of long-lived assets and other expense (income), net in our consolidated statements of income (loss) for the respective year.

Revolving Credit Facilities

On November 29, 2012, Nabors Delaware and Nabors Canada entered into a credit agreement (the New Credit Agreement) under which the lenders committed to provide up to $1.5 billion under an unsecured revolving credit facility. The New Credit Agreement also provides an option to add other lenders and increase the aggregate principal amount of commitments to $1.95 billion. The revolving credit facility matures in November 2017 and can be used for general corporate purposes, including capital expenditures and working capital. We fully and unconditionally guarantee the obligations under the New Credit Agreement.

At the same time we entered into the New Credit Agreement, we and Nabors Delaware replaced both unsecured revolving credit facilities established in September 2010 and April 2011, respectively, and repaid all amounts outstanding with this agreement. In addition, we terminated a Canadian unsecured revolving credit facility.

The Credit Agreement bears interest with the following terms:

- U.S. dollar-denominated borrowings bear interest, at Nabors Delaware s option, for either (x) the U.S. Base Rate (as defined below) plus the applicable interest margin, calculated on the basis of the actual number of days elapsed in a year of 365 days and payable quarterly in arrears or (y) interest periods of one, two, three or six months at an annual rate equal to LIBOR for the corresponding deposits of U.S. dollars, plus the applicable interest margin. The U.S. Base Rate is defined, for any day, as a fluctuating rate per annum equal to the highest of (i) the Federal Funds Rate, as published by the Federal Reserve Bank of New York, plus 1/2 of 1%, (ii) the corporate base rate of interest established by Citibank, N.A. from time to time and (iii) LIBOR for an interest period of one month beginning on such day plus 1.05%.

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- Canadian dollar-denominated borrowings under the Credit Agreement will bear interest, at Nabors Canada s option, at (a) the Canadian Base Rate (as defined below) plus the applicable interest margin, calculated on the basis of the actual number of days elapsed in a year of 365 days and payable quarterly in arrears, (b) interest periods of one, two, three or six months at an annual rate equal to LIBOR for the corresponding deposits of U.S. dollars, plus the applicable interest margin or (c) the Canadian Prime Rate (as defined below) plus the applicable interest margin, calculated on the basis of the actual number of days elapsed in a year of 365 days and payable quarterly in arrears. The Canadian Base Rate is defined, for any day, as a fluctuating rate per annum equal to the highest of (x) the Federal Funds Rate, as published by the Federal Reserve Bank of New York, plus 1%, (y) the rate of interest per annum that HSBC Bank Canada charges to customers of varying degrees of creditworthiness for US dollar demand loans in Canada and (z) LIBOR for an interest period of one month beginning on such day plus 1%. The Canadian Prime Rate is defined, for any day, as a fluctuating rate per annum equal to the greater of (i) the rate of interest per annum that HSBC Bank Canada charges to customers of varying degrees of creditworthiness for US dollar demand loans in Canada and (ii) the rate of interest per annum equal to the average annual yield for one month Canadian dollar bankers acceptances as of such day.

As of December 31, 2012, we had $610 million of remaining availability from a total of $1.5 billion under this revolving credit facility. The weighted average interest rate on borrowings at December 31, 2012 was 1.51%.

The Credit Agreement contains various covenants and restrictive provisions that limit our ability to incur additional indebtedness, make investments or loans and create liens and require us to maintain a net funded indebtedness to total capitalization ratio, as defined in the Credit Agreement. We were in compliance with all covenants under the agreement at December 31, 2012. If we should fail to perform our obligations under the covenants, the Credit Agreement could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable.

Short-Term Borrowings

We had nine letter-of-credit facilities with various banks as of December 31, 2012. Availability and borrowings under our letter-of-credit facilities are as follows:

		(In thousands)
Credit available	$	358,649
Less: Letters of credit outstanding, inclusive of financial and performance guarantees		57,303
Remaining availability	$	301,346

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Note 13 Income Taxes

We apply the provisions of the Income Taxes Topic in the ASC relating to uncertain tax positions. The change in our unrecognized tax benefits for years ended December 31, 2012, 2011 and 2010 were as follows:

	Year Ended December 31,		
	2012	2011	2010
	(In thousands)		
Balance as of January 1	$ 68,848	$ 81,174	$ 69,048
Additions based on tax positions related to the current year	922	1,850	1,026
Additions for tax positions of prior years	16,372(1)	11,748	17,060
Reductions for tax positions for prior years	(1,174)	(11,082)	(4,709)
Settlements	(1,018)	(14,842)	(1,251)
Balance as of December 31	$ 83,950	$ 68,848	$ 81,174

(1) Includes an unrecognized tax benefit of $10.4 million related to a Mexico audit assessment.

The balance also represents the amount of unrecognized tax benefits that, if recognized, would favorably impact the effective income tax rate in future periods. As of December 31, 2012, 2011 and 2010, we had approximately $42.8 million, $28.2 million and $42.9 million, respectively, of interest and penalties related to our total gross unrecognized tax benefits. During the years ended December 31, 2012, 2011 and 2010, we accrued and recognized estimated interest related to unrecognized tax benefits and penalties of approximately $2.7 million, $4.6 million and $5.1 million, respectively. We recognize interest and penalties related to income tax matters in the income tax expense line item in our consolidated statements of income (loss).

We are subject to income taxes in the United States and numerous other jurisdictions. A number of our United States and non-United States income tax returns from 1998 through 2011 are currently under audit examination. We anticipate that several of these audits could be finalized within the next 12 months. It is possible that the benefit relating to our unrecognized tax positions could significantly increase or decrease within the next 12 months. However, based on the current status of examinations, and the protocol for finalizing audits with the relevant tax authorities, which could include formal legal proceedings, it is not possible to estimate the future impact of the amount of changes, if any, to recorded uncertain tax positions at December 31, 2012.

Income (loss) from continuing operations before income taxes was comprised of the following:

	Year Ended December 31,		
	2012	2011	2010
United States and Other Jurisdictions	(In thousands)		
United States	$ 190,848	$ 178,270	$ (82,723)
Other jurisdictions	83,835	309,499	376,293
Income (loss) before income taxes from continuing operations	$ 274,683	$ 487,769	$ 293,570

Income taxes have been provided based upon the tax laws and rates in the countries where we operate. We are a Bermuda exempted company. Bermuda does not impose corporate income taxes. Our U.S. subsidiaries are subject to a U.S. federal tax rate of 35%.

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Income tax expense (benefit) from continuing operations consisted of the following:

	Year Ended December 31, 2012	2011 (In thousands)	2010
Current:			
U.S. federal	$ 25,802	$ 27,649	$ (137,847)
Outside the U.S.	82,950	43,732	54,779
State	34,242	38,321	5,859
	$ 142,994	$ 109,702	$ (77,209)
Deferred:			
U.S. federal	$ (78,556)	$ 41,540	$ 97,114
Outside the U.S.	(18,479)	4,413	13,607
State	(13,331)	(13,050)	3,438
	$ (110,366)	$ 32,903	$ 114,159
Income tax expense (benefit)	$ 32,628	$ 142,605	$ 36,950

Nabors is not subject to tax in Bermuda. A reconciliation of the differences between taxes on income (loss) before income taxes computed at the appropriate statutory rate and our reported provision for income taxes follows:

	Year Ended December 31, 2012	2011 (In thousands)	2010
Income tax provision at statutory (Bermuda rate of 0%)	$	$	$
Taxes on U.S. and other international earnings (losses) at greater than the Bermuda rate	(48,188)	112,094	18,686
Increase (decrease) in valuation allowance	33,730	(6,450)	2,407
Effect of change in tax rate		(258)	40
Tax reserves and interest	26,176	11,948	8,808
State income taxes	20,910	25,271	7,009
Income tax expense (benefit)	$ 32,628	$ 142,605	$ 36,950
Effective tax rate	11.9%	29.2%	12.6%

The changes in our effective tax rate from 2011 to 2012 and from 2010 to 2011 are mainly a result of the proportion of income generated in the United States versus the international jurisdictions where we operate. Income generated in the United States is generally taxed at a higher rate than other jurisdictions.

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The significant components of our deferred tax assets and liabilities were as follows:

	December 31, 2012	December 31, 2011
	(In thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 1,826,597	$ 2,009,318
Equity compensation	29,337	25,937
Deferred revenue	33,523	32,200
Tax credit and other attribute carryforwards	110,563	90,297
Insurance loss reserves	10,873	24,598
Other	104,699	114,043
Subtotal	2,115,592	2,296,393
Valuation allowance	(1,520,852)	(1,485,540)
Deferred tax assets:	$ 594,740	$ 810,853
Deferred tax liabilities:		
Depreciation and amortization for tax in excess of book expense	$ 945,888	$ 1,317,256
Variable interest investments	144,020	116,005
Other		34,822
Deferred tax liability	$ 1,089,908	$ 1,468,083
Net deferred assets (liabilities)	$ (495,168)	$ (657,230)
Balance Sheet Summary		
Net current deferred asset	$ 110,480	$ 127,874
Net noncurrent deferred asset (1)	4,408	13,090
Net current deferred liability (2)	(10,721)	(269)
Net noncurrent deferred liability	(599,335)	(797,925)
Net deferred asset (liability)	$ (495,168)	$ (657,230)

(1) This amount is included in other long-term assets.

(2) This amount is included in accrued liabilities.

For U.S. federal income tax purposes, we have net operating loss (NOL) carryforwards of approximately $649 million that, if not utilized, will expire between 2018 and 2031. The NOL carryforwards for alternative minimum tax purposes are approximately $528 million. Additionally, we have NOL carryforwards in other jurisdictions of approximately $5.5 billion of which $530 million that, if not utilized, will expire at various times from 2013 to 2032. We provide a valuation allowance against NOL carryforwards in various tax jurisdictions based on our consideration of existing temporary differences and expected future earning levels in those jurisdictions. We have recorded a deferred tax asset of approximately $1.45 billion as of December 31, 2012 relating to NOL carryforwards that have an indefinite life in several non-U.S. jurisdictions. A valuation allowance of approximately $1.45 billion has been recognized because we believe it is more likely than not that substantially all of the deferred tax asset will not be realized.

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The NOL carryforwards by year of expiration:

Year Ended December 31,	Total	U.S. Federal (In thousands)	Non-U.S.
2013	$ 24,552	$	$ 24,552
2014	4,531		4,531
2015	21,567		21,567
2016	34,058		34,058
2017	47,961		47,961
2018	51,197	11,703	39,494
2019	28,518	17,722	10,796
2020	16,394		16,394
2021	23,086		23,086
2022	1,514		1,514
2026			
2027	114		114
2028	22,982		22,982
2029	51,813		51,813
2030	329,997	280,732	49,265
2031	413,899	338,640	75,259
2032	106,587		106,587
Subtotal: expiring NOLs	$ 1,178,770	$ 648,797	$ 529,973
Non-expiring NOLs	4,972,658		4,972,658
Total	$ 6,151,428	$ 648,797	$ 5,502,631

In addition, for state income tax purposes, we have net operating loss carryforwards of approximately $382 million that, if not utilized, will expire at various times from 2013 to 2032.

Under U.S. federal tax law, the amount and availability of loss carryforwards (and certain other tax attributes) are subject to a variety of interpretations and restrictive tests applicable to Nabors and our subsidiaries. The utilization of these carryforwards could be limited or effectively lost upon certain changes in our shareholder base. Accordingly, although we believe substantial loss carryforwards are available to us, no assurance can be given that they will be available in the future.

Various bills have been introduced in the U.S. Congress that could reduce or eliminate the U.S. tax benefits associated with our 2002 reorganization as a Bermuda company. Legislation enacted by Congress in 2004 provides that a corporation that reorganized in a foreign jurisdiction on or after March 4, 2003 be treated as a domestic corporation for United States federal income tax purposes. There has been and we expect that there may continue to be legislation proposed in Congress from time to time which, if enacted, could limit or eliminate the tax benefits associated with our reorganization.

Because we cannot predict whether legislation will ultimately be adopted, no assurance can be given that the tax benefits associated with our reorganization will ultimately accrue to the benefit of the Company and its shareholders. It is possible that future changes to tax laws (including tax treaties) could impact our ability to realize the tax savings recorded to date as well as future tax savings resulting from our reorganization.

Note 14 Common Shares

Our authorized share capital consists of 800 million common shares, par value $.001 per share, and 25 million preferred shares, par value $.001 per share. Common shares issued were 318,813,500 and 317,042,324 at $.001 par value as of December 31, 2012 and 2011, respectively. No preferred shares have been issued. The preferred stock is

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issuable in one or more classes or series, full, limited or no voting rights, designations, preferences, special rights, qualifications, limitations and restrictions as may be determined by Nabors Industries Ltd. s board.

From time to time, treasury shares may be reissued. When shares are reissued, we use the weighted-average-cost method for determining cost. The difference between the cost of the shares and the issuance price is added to or deducted from our capital in excess of par value account. No shares have been purchased during 2012, 2011 and 2010.

During 2012, 2011 and 2010 our outstanding shares increased by 807,142, 82,138 and 136,818 shares, respectively, pursuant to a share settlement of stock options exercised by our key officers, directors and employees. As part of these transactions, these individuals surrendered unexercised vested stock options to the Company with a value of approximately $79.6 million, $7.6 million and $77.0 million, respectively, to satisfy the option exercise price and related income taxes for 2012, 2011 and 2010.

In 2012, 2011 and 2010, the Compensation Committee of our Board of Directors granted restricted stock awards to some of our executive officers, other key employees, and independent directors. We awarded 944,015, 1,096,379 and 538,496 restricted shares at an average market price of $20.69, $27.32 and $22.15 to these individuals for 2012, 2011 and 2010, respectively. See Note 8 Share-Based Compensation for a summary of our restricted stock and option awards as of December 31, 2012.

During 2012, 2011 and 2010 our employees exercised vested options to acquire 1.1 million, 1.1 million and .7 million of our common shares, respectively. During 2012, we received $17.4 million relating to exercised vested options, and we used approximately $21 million to repurchase surrendered unexercised vested options and to satisfy related tax withholding obligations pursuant to these stock option share settlements and exercises by our employees. During 2011 and 2010, we received net proceeds of $11.6 million and $8.2 million, respectively, relating to exercised vested options.

Shareholder Rights Plan

On July 16, 2012, the Board of Directors declared the issuance of one preferred share purchase right (a Right) for each Common Share issued and outstanding on July 27, 2012 (the Record Date) to the shareholders of record on that date. Each Right entitles the registered holder to purchase from the Company one one-thousandth of a Series A Junior Participating Preferred Share, par value US$0.001 per share (the Preferred Shares), of the Company, at a price of $70.00 per one one-thousandth of a Preferred Share (the Purchase Price), subject to adjustment.

Until the Distribution Date, the Rights will be evidenced, with respect to any Common Share certificates issued and outstanding as of the Record Date, by such Common Share certificate together with a copy of a summary of rights. The Distribution Date is defined as the earlier to occur of:

(i) 10 days following a public announcement that a person or group of affiliated or associated persons (an Acquiring Person) has acquired beneficial ownership (including derivative positions) of 10% or more of the issued and outstanding Common Shares (or, in the event an exchange is effected in accordance with Section 24 of the Rights Agreement and the Board of Directors determines that a later date is advisable, then such later date that is not more than 20 days after such public announcement); or

(ii) 10 business days (or such later date as may be determined by action of the Board of Directors prior to such time as any Person becomes an Acquiring Person) following the commencement of, or announcement of an intention to make, a tender offer or exchange offer the consummation of which would result in the beneficial ownership by a person or group of 10% or more of the issued and outstanding Common Shares.

The Rights are not exercisable until the Distribution Date. The Rights will expire on July 16, 2013 (the Final Expiration Date), unless the Final Expiration Date is extended or the Rights are earlier redeemed by the Company, in each case.

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Note 15 Subsidiary Preferred Stock

NCPS (formerly, Superior), a wholly owned subsidiary, had 75,000 shares of Series A Preferred Stock (preferred stock), $0.01 par value per share, outstanding at December 31, 2012. There are 10,000,000 shares authorized. The preferred stock is issuable in series with such voting rights, if any, designations, powers, preferences and other rights and such qualifications, limitations and restrictions as may be determined by its board; the board may also fix the number of shares constituting each series and increase or decrease the number of shares of any series.

The preferred stock is perpetual and ranks senior to the subsidiary s common stock with respect to payment of dividends, and amounts upon liquidation, dissolution or winding up.

We have presented the preferred stock within the mezzanine section of our consolidated balance sheets and have accounted for the preferred stock under the ASC Topic for Distinguishing Liabilities from Equity.

Dividends

Holders of the preferred stock are entitled to receive, when and if declared by its board, out of assets legally available therefor, cumulative cash dividends at the rate per annum of $40.00 per share of preferred stock. Dividends on the preferred stock are payable quarterly in arrears on December 1, March 1, June 1 and September 1 of each year (and, in the case of any undeclared and unpaid dividends, at such additional times and for such interim periods, if any, as determined by its board), at such annual rate. Dividends are cumulative from the date of the original issuance of the preferred stock, whether or not in any dividend period or periods we have assets legally available for the payment of such dividends.

As of December 31, 2012, dividends on outstanding shares of preferred stock had been declared and paid in full with respect to each quarter since its issuance.

Liquidation Preference

Holders of preferred stock are entitled to receive, in the event that NCPS is liquidated, dissolved or wound up, whether voluntarily or involuntarily, $1,000 per share (the Liquidation Value) plus an amount per share equal to all dividends undeclared and unpaid thereon to the date of final distribution (the Liquidation Preference), and no more. Until the holders of preferred stock have been paid the Liquidation Preference in full, NCPS may not make any payment to any holder of stock that ranks junior to the preferred stock upon liquidation, dissolution or winding up. As of December 31, 2012, the preferred stock had a total Liquidation Preference of $75.0 million.

Redemption

The preferred stock is redeemable, in whole or in part, and at NCPS s option, at any time on or after November 18, 2013, for a redemption price of 101% of the Liquidation Value, plus all accrued dividends. The redemption price is payable in cash.

As a result of the acquisition in 2010, each share of preferred stock is convertible, at the option of the holder thereof, into $22.12 for each share of NCPS common stock into which the preferred share would have been convertible prior to the acquisition (a deemed common share). The preferred shares had a conversion price of $25.00 per deemed common share prior to the acquisition (equivalent to a conversion rate of 40 deemed common shares for each share of preferred stock), representing 3,000,000 deemed common shares. This results in a redemption value of $66.4 million at December 31, 2012, payable in cash. The right to convert shares of preferred stock that may be called for redemption will terminate at the close of business on the day preceding a redemption date.

Voting Rights

Except as otherwise required from time to time by applicable law or upon certain events of default, the holders of preferred stock have no voting rights, and their consent is not required for taking any corporate action. When and if the holders of the preferred stock are entitled to vote, each holder will be entitled to one vote per share.

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Note 16 Pension, Postretirement and Postemployment Benefits

Pension Plans

In conjunction with our acquisition of Pool Energy Services Co. (Pool) in November 1999, we acquired the assets and liabilities of a defined benefit pension plan, the Pool Company Retirement Income Plan (the Pool Pension Plan). Benefits under the Pool Pension Plan are frozen and participants were fully vested in their accrued retirement benefit on December 31, 1998.

Summarized information on the Pool Pension Plan is as follows:

	Pension Benefits	
	2012	2011
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 26,659	$ 20,628
Remeasurement		1,517
Interest cost	1,116	1,198
Actuarial loss (gain)	2,107	3,975
Benefit payments	(677)	(659)
Benefit obligation at end of year (1)	$ 29,205	$ 26,659
Change in plan assets:		
Fair value of plan assets at beginning of year	$ 16,352	$ 15,219
Actual (loss) returns on plan assets	1,598	480
Employer contributions	1,507	1,312
Benefit payments	(677)	(659)
Fair value of plan assets at end of year	$ 18,780	$ 16,352
Funded status:		
Underfunded status at end of year	$ (10,425)	$ (10,307)
Amounts recognized in consolidated balance sheets:		
Other long-term liabilities	$ (10,425)	$ (10,307)

(1) As of December 31, 2012 and 2011, the accumulated benefit obligation was the same as the projected benefit obligation.

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	Year Ended December 31, 2012	2011	2010
	(In thousands)		
Components of net periodic benefit cost (recognized in our consolidated statements of income):			
Interest cost	$ 1,116	$ 1,198	$ 1,116
Expected return on plan assets	(1,086)	(1,008)	(909)
Recognized net actuarial loss	1,034	628	457
Net periodic benefit cost	$ 1,064	$ 818	$ 664
Weighted-average assumptions:			
Weighted-average discount rates	3.75%	4.25%	5.50%
Expected long-term rate of return on plan assets	6.50%	6.50%	6.50%

For the years ended December 31, 2012, 2011 and 2010, the net actuarial loss amounts included in other comprehensive income (loss) were approximately $(12.7) million, $(12.1) million and $(6.7) million, respectively. There were no other components, such as prior service costs or transition obligations relating to pension costs recorded within other comprehensive income (loss) during 2011, 2010 and 2009.

The amount included in other comprehensive income (loss) that is expected to be recognized as a component of net periodic benefit cost during 2013 is approximately $1.1 million.

We analyze the historical performance of investments in equity and debt securities, together with current market factors such as inflation and interest rates to help us make assumptions necessary to estimate a long-term rate of return on plan assets. Once this estimate is made, we review the portfolio of plan assets and make adjustments thereto that we believe are necessary to reflect a diversified blend of investments in equity and debt securities that is capable of achieving the estimated long-term rate of return without assuming an unreasonable level of investment risk.

The following table sets forth, by level within the fair value hierarchy, the investments in the Pool Pension Plan as of December 31, 2012. The investments fair value measurement level within the fair value hierarchy is classified in its entirety based on the lowest level of input that is significant to the measurement.

	Fair Value as of December 31, 2012 Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets: (1)				
Cash	$	$ 520	$	$ 520
Short-term investments:				
Available-for-sale equity securities (2)		10,361		10,361
Available-for-sale debt securities (3)		7,899		7,899
Total investments		18,260		18,260
Total	$	$ 18,780	$	$ 18,780

(1) Includes investments in collective trust funds that are valued based on the fair value of the underlying investments using quoted prices in active markets or other significant inputs that are deemed observable.

(2) Includes funds that invest primarily in U.S. common stocks and foreign equity securities.

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(3) Includes funds that invest primarily in investment grade debt.

The measurement date used to determine pension measurements for the plan is December 31.

Our weighted-average asset allocations as of December 31, 2012 and 2011, by asset category are as follows:

	Pension Benefits	
	2012	2011
Cash	3%	2%
Equity securities	55%	56%
Debt securities	42%	42%
Total	100%	100%

We invest plan assets based on a total return on investment approach, pursuant to which the plan assets include a diversified blend of investments in equity and debt securities toward a goal of maximizing the long-term rate of return without assuming an unreasonable level of investment risk. We determine the level of risk based on an analysis of plan liabilities, the extent to which the value of the plan assets satisfies the plan liabilities and our financial condition. Our investment policy includes target allocations approximating 55% investment in equity securities and 45% investment in debt securities. The equity portion of the plan assets represents growth and value stocks of small, medium and large companies. We measure and monitor the investment risk of the plan assets both on a quarterly basis and annually when we assess plan liabilities.

We expect to contribute approximately $.6 million to the Pool Pension Plan in 2013. This is based on the sum of (1) the minimum contribution for the 2012 plan year that will be made in 2012 and (2) the estimated minimum required quarterly contributions for the 2013 plan year. We made contributions to the Pool Pension Plan in 2012 and 2011 totaling $1.5 million and $1.3 million, respectively.

As of December 31, 2012, we expect that benefits to be paid in each of the next five years after 2012 and in the aggregate for the five years thereafter will be as follows:

	(In thousands)
2013	$ 939
2014	1,055
2015	1,159
2016	1,237
2017	1,348
2018 - 2022	8,081
	$ 13,819

Some of our employees are covered by defined contribution plans. Our contributions to the plans totaled $19.0 million and $22.9 million for the years ended December 31, 2012 and 2011, respectively. Nabors does not provide post-employment benefits to its employees, except for employees covered under the Pool Pension Plan.

Note 17 Related-Party Transactions

Nabors and certain current and former key employees, including Messrs. Petrello and Isenberg, entered into split-dollar life insurance agreements, pursuant to which we pay a portion of the premiums under life insurance policies with respect to these individuals and, in some instances, members of their families. These agreements provide that we are reimbursed for the premium payments upon the occurrence of specified events, including the death of an insured individual. Any recovery of premiums paid by Nabors could be limited to the cash surrender value of the policies under certain circumstances. As such, the values of these policies are recorded at their respective cash surrender values in our consolidated balance sheets. We have made premium payments to date totaling $6.3 million related to these policies. The cash surrender value of these policies of approximately $5.8

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million is included in other long-term assets in our consolidated balance sheets as of December 31, 2012 and 2011, respectively. We will not be reimbursed for the premium payments paid on behalf of Mr. Isenberg as provided by the agreement entered into on February 2, 2012 (see discussion on agreement below).

Under the Sarbanes-Oxley Act of 2002, the payment of premiums by Nabors under the agreements with Messrs. Petrello and Isenberg could be deemed to be prohibited loans by us to these individuals. Consequently, we have paid no premiums related to our agreements with these individuals since the adoption of the Sarbanes-Oxley Act.

The Company and Nabors Delaware entered into an agreement with Mr. Isenberg, then Chairman of our Board of Directors, on February 2, 2012 but effective December 31, 2011, pursuant to which:

- He voluntarily terminated both his employment with the Company and his Employment Agreement, and forwent any right to payment in connection with such termination, including a possible payment of $100 million in connection with the Company s appointment of a new chief executive officer on October 28, 2011, which Mr. Isenberg could have treated as a constructive termination under his employment agreement;

- He would continue as Chairman of the Board, but not stand for reelection as a director in June 2012; at that time, he was appointed Chairman Emeritus for a three-year term, which will be extended for additional one-year terms unless terminated by him or by the Company, and receive cash compensation equal to other nonemployee directors;

- Nabors Delaware paid $6,600,000 into an escrow account, which will bear interest at the guaranteed rate of 6% per annum compounded daily and will be distributed either to Mr. Isenberg s estate or to the trustees of his revocable trust;

- He ceased participation in the Company s benefit plans and forfeited any benefits available to him thereunder (including forfeiture of the balance in his deferred bonus account), except as stated below or otherwise required by law:

- he and his spouse continue to participate in medical, dental and life insurance coverage until either receives equivalent coverage and benefits under the plans and programs of a subsequent employer or their death;

- he remains entitled to distribution of vested account balances in the Company s 401(k) plan and its Deferred Compensation Plan;

- he retains certain benefits under the split-dollar life insurance agreements in effect between him and Nabors Delaware

• All of his stock option and restricted stock awards were already fully vested and remain subject to the applicable plans and agreements governing them; and

• He waived all claims or other liabilities related to his Employment Agreement or his termination of employment, and the Company waived certain claims against Mr. Isenberg.

In the ordinary course of business, we enter into various rig leases, rig transportation and related oilfield services agreements with our unconsolidated affiliates at market prices. Revenues from business transactions with these affiliated entities totaled $164.0 million, $218.4 million and $271.6 million for 2012, 2011 and 2010, respectively. Expenses from business transactions with these affiliated entities totaled $.1 million, $.9 million and $3.4 million for 2012, 2011 and 2010, respectively. Additionally, we had accounts receivable from these affiliated entities of $68.7 million and $110.7 million as of December 31, 2012 and 2011, respectively. We had accounts payable to these affiliated entities of $3.2 million and $46.1 million as of December 31, 2012 and 2011, respectively, and long-term payables with these affiliated entities of $.8 million as of those dates, which are included in other long-term liabilities.

In the ordinary course of business, we also provide drilling, well-servicing and other services to LINN Operating, Inc. (LINN), a company of which Mr. Linn, an independent member of our Board of Directors beginning in February 2012, is the Chairman and Chief Executive Office. Revenues from business transactions with LINN totaled $12.5 million during 2012. We had accounts receivable from LINN of $1.9 million as of December 31, 2012. In addition, Mr. Crane, an independent director beginning in February 2012, is Chairman and Chief Executive Officer of Crane Capital Group Inc. (CCG), an investment company that indirectly owns a majority interest in several operating companies, some of which have provided services to us in the ordinary course of business, including international logistics and electricity. During 2012, we made payments for these services of $42.0 million. We had account payable to CCG of $1.4 million as of December 31, 2012.

Prior to December 2012, we owned an interest in Shona Energy Company, LLC (Shona), a company of which Mr. Payne, an independent member of our Board of Directors, was the Chairman and Chief Executive Officer. We acquired our interest in the first quarter of 2010 when we purchased shares of Shona s preferred stock and warrants to purchase additional common shares for $.9 million. During 2011, Shona became a public company in Canada, with voting common shares listed on the TSX Venture Exchange. At December 31, 2011, we held a minority

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interest of approximately 7.55% of the issued and outstanding common shares of Shona. In December 2012, Canacol Energy Ltd. acquired all of Shona s outstanding common shares, resulting in our ownership of a minority interest of approximately 2.17% of the issued and outstanding shares of Canacol Energy Ltd. at December 31, 2012. Mr. Payne is not an officer or director of Canacol Energy Ltd.

Note 18 Commitments and Contingencies

Commitments

Leases

Nabors and its subsidiaries occupy various facilities and lease certain equipment under various lease agreements.

The minimum rental commitments under non-cancelable operating leases, with lease terms in excess of one year subsequent to December 31, 2012, were as follows:

		(In thousands)
2013	$	25,609
2014		16,001
2015		7,646
2016		5,307
2017		2,986
Thereafter		9,527
	$	67,076

The above amounts do not include property taxes, insurance or normal maintenance that the lessees are required to pay. Rental expense relating to operating leases with terms greater than 30 days amounted to $35.5 million, $36.3 million and $26.7 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Minimum Volume Commitment

We have contracts with pipeline companies to pay specified fees based on committed volumes for gas transport and processing. Our pipeline contractual commitments as of December 31, 2012 were as follows:

		(In thousands)
2013	$	67,251
2014		65,535
2015		63,976
2016		47,106
2017		27,949
Thereafter		67,769
	$	339,586

(1) Final commitment period is for the period ending October 2029. See Note 4 Assets Held for Sale and Discontinued Operations for additional discussion.

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Employment Contracts

We have entered into employment contracts with certain of our employees. Our minimum salary and bonus obligations under these contracts as of December 31, 2012 were as follows:

		(In thousands)
2013	$	5,830
2014		2,651
2015		525
2016		
2017		
Thereafter		
	$	9,006

Mr. Petrello has an employment agreement which was amended and restated effective April 1, 2009. The employment agreement provides for an extension of the employment term through March 30, 2013, with automatic one-year extensions which began April 1, 2011, unless either party gives notice of non-renewal. Pursuant to its provisions, the term of his employment agreement has subsequently been extended through March 30, 2014.

Mr. Petrello s employment agreement provides a base salary of $1.3 million. In addition to a base salary, the employment agreement provides for an annual cash bonus in an amount equal to 1.5% of Nabors net cash flow (as defined in the employment agreement) in excess of 15% of the average shareholders equity for each fiscal year. As provided in the employment agreement, the 1.5% of Nabors net cash flow was replaced with 2.0% on October 28, 2011 in connection with his appointment as Chief Executive Officer. For 2012, the annual cash bonus pursuant to the formula was $17.5 million. The employment agreement also provides a quarterly deferred bonus of $.25 million to Mr. Petrello s account under Nabors executive deferred compensation plan for each quarter he is employed beginning June 30, 2009 and ending March 30, 2019.

Mr. Petrello is also eligible for awards under Nabors equity plans, may participate in annual long-term incentive programs and pension and welfare plans on the same basis as other executives, and may receive special bonuses from time to time as determined by the Board of Directors.

Termination in the event of death, disability, or termination without cause (including in the event of a Change in Control). Mr. Petrello s employment agreement provides for a severance payment in the event that it is terminated (i) upon death or disability, (ii) by Nabors prior to its expiration date for any reason other than for Cause (as defined in the agreement), or (iii) by Mr. Petrello for Constructive Termination Without Cause, as defined in the agreement. Termination in the event of a Change in Control (as defined in the employment agreement) is considered a Constructive Termination Without Cause. Mr. Petrello would be entitled to receive within 30 days of his death or disability a payment of $50 million or in the event of Termination Without Cause or Constructive Termination Without Cause, a payment based on a formula of three times the average of his base salary and annual bonus (calculated as though the bonus formula under the new employment agreement had been in effect) paid during the three fiscal years preceding the termination. If, by way of example, Mr. Petrello were Terminated Without Cause subsequent to December 31, 2012, his payment would be approximately $40.8 million. The formula will be further reduced to two times the average stated above effective April 1, 2015.

The Company does not have insurance to cover its obligations in the event of Mr. Petrello s death, disability, or termination without cause, and the Company has not recorded an expense or accrued a liability relating to the potential obligation.

In addition, under the employment agreement, Mr. Petrello would be entitled to receive (a) any unvested restricted stock or stock options outstanding, which would immediately and fully vest; (b) any amounts earned, accrued or owing to him but not yet paid (including executive benefits, life insurance, disability benefits and reimbursement of expenses and perquisites), which would be continued through the later of the expiration date or three years after the termination date; (c) continued participation in medical, dental and life insurance coverage until he received equivalent benefits or coverage through a subsequent employer or until his death or the death of his spouse, whichever were later; and (d) any other or additional benefits in accordance with applicable plans and programs of Nabors. The vesting of unvested equity awards would not result in the recognition of any additional compensation expense, as all compensation expense related to his outstanding awards had been recognized by December 31, 2012. In addition, the employment agreement eliminates all tax gross-ups, including tax gross-ups on golden parachute excise taxes. Estimates of the cash value of Nabors obligations to Mr. Petrello under (b), (c) and (d) above are included in the payment amounts above.

Other Obligations. In addition to salary and bonus, Mr. Petrello receives group life insurance at an amount at least equal to three times his base salary, various split-dollar life insurance policies, reimbursement of expenses, various perquisites and a personal umbrella insurance policy in the amount of $5 million. Premiums payable under the split-dollar life insurance policies were suspended as a result of the adoption of the Sarbanes-Oxley Act of 2002.

Contingencies

Income Tax Contingencies

We are subject to income taxes in the United States and numerous other jurisdictions. Significant judgment is required in determining our worldwide provision for income taxes. In the ordinary course of our business, there are many transactions and calculations where the ultimate tax determination is uncertain. We are regularly audited by tax authorities. Although we believe our tax estimates are reasonable, the final determination of tax audits and any related litigation could be materially different than what is reflected in income tax provisions and accruals. An audit or litigation could materially affect our financial position, income tax provision, net income, or cash flows in the period or periods challenged.

It is possible that future changes to tax laws (including tax treaties) could impact our ability to realize the tax savings recorded to date as well as future tax savings, resulting from our 2002 corporate reorganization. See Note 13 Income Taxes for additional discussion.

On September 14, 2006, Nabors Drilling International Limited, one of our wholly owned Bermuda subsidiaries (NDIL), received a Notice of Assessment from Mexico s federal tax authorities in connection with the audit of NDIL s Mexico branch for 2003. The notice proposes to deny depreciation expense deductions relating to drilling rigs operating in Mexico in 2003. The notice also proposes to deny a deduction for payments made to an affiliated company for the procurement of labor services in Mexico. The amount assessed was approximately $19.8 million (including interest and penalties). Nabors and its tax advisors previously concluded that the deductions were appropriate. NDIL s Mexico branch took similar deductions for depreciation and labor expenses from 2004 to 2008. On June 30, 2009, the government proposed similar assessments against the Mexico branch of another wholly owned Bermuda subsidiary, Nabors Drilling International II Ltd. (NDIL II) for 2006. We anticipate that a similar assessment will eventually be proposed against NDIL for 2005 through 2008 and against NDIL II for 2007 to 2010. We believe that the potential assessments will range from $6 million to $26 million per year for the period from 2005 to 2009, and in the aggregate, would be approximately $90 million to $95 million. Although Nabors and its tax advisors previously concluded that the deductions were appropriate for each of the years, a reserve has been recorded in accordance with GAAP. The statute of limitations for NDIL s 2004 tax year expired. Accordingly, during the fourth quarter of 2010, we released $7.4 million from our tax reserves, which represented the reserve recorded for that tax year. If these additional assessments were made and we ultimately did not prevail, we would be required to recognize additional tax for the amount in excess of the current reserve.

Self-Insurance

We estimate the level of our liability related to insurance and record reserves for these amounts in our consolidated financial statements. Our estimates are based on the facts and circumstances specific to existing claims and our past experience with similar claims. These loss estimates and accruals recorded in our financial statements for claims have historically been reasonable in light of the actual amount of claims paid and are actuarily supported. Although we believe our insurance coverage and reserve estimates are reasonable, a significant accident or other event that is not fully covered by insurance or contractual indemnity could occur and could materially affect our financial position and results of operations for a particular period.

We self-insure for certain losses relating to workers compensation, employers liability, general liability, automobile liability and property damage. Some workers compensation claims, employers liability and marine employers liability claims are subject to a $2.0 million per-occurrence deductible. Some automobile liability is subject to a $1.0 million deductible. General liability claims are subject to a $5.0 million per-occurrence deductible.

In addition, we are subject to a $5.0 million deductible for land rigs and for offshore rigs. This applies to all kinds of risks of physical damage except for named windstorms in the U.S. Gulf of Mexico for which we are self-insured.

Political risk insurance is procured for select operations in South America, Africa, the Middle East and Asia. Losses are subject to a $.25 million deductible, except for Colombia, which is subject to a $.5 million deductible. There is no assurance that such coverage will adequately protect Nabors against liability from all potential consequences.

As of December 31, 2012 and 2011, our self-insurance accruals totaled $171.2 million and $157.8 million, respectively, and our related insurance recoveries/receivables were $24.6 million and $18.7 million, respectively.

Litigation

Nabors and its subsidiaries are defendants or otherwise involved in a number of lawsuits in the ordinary course of business. We estimate the range of our liability related to pending litigation when we believe the amount and range of loss can be estimated. We record our best estimate of a loss when the loss is considered probable. When a liability is probable and there is a range of estimated loss with no best estimate in the range, we record the minimum estimated liability related to the lawsuits or claims. As additional information becomes available, we assess the potential liability related to our pending litigation and claims and revise our estimates. Due to uncertainties related to the resolution of lawsuits and claims, the ultimate outcome may differ from our estimates. For matters where an unfavorable outcome is reasonably possible and significant, we disclose the nature of the matter and a range of potential exposure, unless an estimate cannot be made at the time of disclosure. In the opinion of management and based on liability accruals provided, our ultimate exposure with respect to these pending lawsuits and claims is not expected to have a material adverse effect on our consolidated financial position or cash flows, although they could have a material adverse effect on our results of operations for a particular reporting period.

On July 5, 2007, we received an inquiry from the U.S. Department of Justice relating to its investigation of one of our vendors and compliance with the Foreign Corrupt Practices Act. The inquiry related to transactions with and involving Panalpina, which provided freight forwarding and customs clearance services to some of our affiliates. The inquiry focused on transactions in Kazakhstan, Saudi Arabia, Algeria and Nigeria. The Audit Committee of our Board of Directors engaged outside counsel to review some of our transactions with this vendor, received periodic updates at its regularly scheduled meetings, and the Chairman of the Audit Committee received updates between meetings as circumstances warranted. The investigation included a review of certain amounts paid to and by Panalpina in connection with obtaining permits for the temporary importation of equipment and clearance of goods and materials through customs. Both the SEC and the Department of Justice have been advised of our investigation. In April, the SEC advised us that it concluded its review of this matter and did not intend to recommend any enforcement action against us. In February 2013, the Department of Justice likewise advised us that it concluded its inquiry, also without recommending any enforcement action against us.

In 2009, the Court of Ouargla (in Algeria) entered a judgment of approximately $19.7 million against us relating to alleged customs infractions in 2009. We believe we did not receive proper notice of the judicial proceedings, and that the amount of the judgment was excessive in any case. We asserted the lack of legally required notice as a basis for challenging the judgment on appeal to the Algeria Supreme Court. In May 2012, that court reversed the lower court and remanded the case to the Ouargla Court of Appeals for treatment consistent with the Supreme Court s ruling. In January 2013, the Ouargla Court of Appeals reinstated the judgment. We have again lodged an appeal to the Algeria Supreme Court, asserting the same challenges as before. Based upon our understanding of applicable law and precedent, we continue to believe that we will prevail. We do not believe that a loss is probable and have not accrued any amounts related to this matter. If we are ultimately required to pay a fine or judgment related to this matter, the amount of the loss could range from approximately $140,000 to $19.7 million.

In March 2011, the Court of Ouargla entered a judgment of approximately $39.1 million against us relating to alleged violations of Algeria s foreign currency exchange controls, which require that goods and services provided locally be invoiced and paid in local currency. The case relates to certain foreign currency payments made to us by CEPSA, a Spanish operator, for wells drilled in 2006. Approximately $7.5 million of the total contract amount was

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paid offshore in foreign currency, and approximately $3.2 million was paid in local currency. The judgment includes fines and penalties of approximately four times the amount at issue, and is not payable pending appeal. We have appealed the ruling based on our understanding that the law in question applies only to resident entities incorporated under Algerian law. An intermediate court of appeals has upheld the lower court s ruling, and we have appealed the matter to the Algeria Supreme Court. While our payments were consistent with our historical operations in the country, and, we believe, those of other multinational corporations there, as well as interpretations of the law by the Central Bank of Algeria, the ultimate resolution of this matter could result in a loss of up to $31.1 million in excess of amounts accrued.

On September 21, 2011, we received an informal inquiry from the SEC related to perquisites and personal benefits received by the officers and directors of Nabors, including their use of non-commercial aircraft. Our Audit Committee and Board of Directors have been apprised of this inquiry and we are cooperating with the SEC. The ultimate outcome of this process cannot be determined at this time.

On March 9, 2012, Nabors Global Holdings II Limited (NGH2L) signed a contract with ERG Resources, LLC (ERG) relating to the sale of all of the Class A shares of NGH2L s wholly owned subsidiary, Ramshorn International Limited, an oil and gas exploration company. When ERG failed to meet its closing obligations, NGH2L terminated the transaction on March 19, 2012 and, as contemplated in the agreement, retained ERG s $3 million escrow deposit. ERG filed suit the following day in the 61st Judicial District Court of Harris County, Texas, in a case styled ERG Resources, LLC v. Nabors Global Holdings II Limited, Ramshorn International Limited, and Parex Resources, Inc.; Cause No. 2012-16446, seeking injunctive relief to halt any sale of the shares to a third party, specifically naming as defendant Parex Resources, Inc. (Parex). The lawsuit also seeks monetary damages of up to $100 million based on an alleged breach of contract by NGH2L and alleged tortious interference with contractual relations by Parex. Nabors successfully defeated ERG s effort to obtain a temporary restraining order from the Texas court on March 20, 2012. On March 23, 2012, ERG filed and obtained an ex parte stay from the Supreme Court of Bermuda (Commercial Court), in a case styled as ERG Resources LLC v. Nabors Global Holdings II Limited, Case No. 2012: No. 110. Nabors challenged the stay and, following a series of oral hearings on the matter, the Bermuda court discharged the stay by a ruling dated April 5, 2012. Nabors completed the sale of Ramshorn s Class A shares to a Parex affiliate on April 12, 2012, which mooted ERG s application for a temporary injunction that was scheduled for hearing by the Texas court on April 13, 2012. ERG retains its causes of action for monetary damages, but Nabors believes the claims are foreclosed by the terms of the agreement and are without factual or legal merit. Although we are vigorously defending the lawsuit, its ultimate outcome cannot be determined at this time.

Off-Balance Sheet Arrangements (Including Guarantees)

We are a party to some transactions, agreements or other contractual arrangements defined as off-balance sheet arrangements that could have a material future effect on our financial position, results of operations, liquidity and capital resources. The most significant of these off-balance sheet arrangements involve agreements and obligations under which we provide financial or performance assurance to third parties. Certain of these agreements serve as guarantees, including standby letters of credit issued on behalf of insurance carriers in conjunction with our workers compensation insurance program and other financial surety instruments such as bonds. In addition, we have provided indemnifications, which serve as guarantees, to some third parties. These guarantees include indemnification provided by Nabors to our share transfer agent and our insurance carriers. We are not able to estimate the potential future maximum payments that might be due under our indemnification guarantees.

Management believes the likelihood that we would be required to perform or otherwise incur any material losses associated with any of these guarantees is remote. The following table summarizes the total maximum amount of financial guarantees issued by Nabors:

			Maximum Amount		
	2013	**2014**	**2015**	**Thereafter**	**Total**

		(In thousands)		
Financial standby letters of credit and other financial surety instruments	$ 92,931	105		$ 93,036

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Note 19 Earnings (Losses) Per Share

We include unvested restricted stock awards in the calculation of basic and diluted earnings per share using the two-class method as required by the Earnings Per Share Topic of the ASC.

A reconciliation of the numerators and denominators of the basic and diluted earnings (losses) per share computations is as follows:

	Year Ended December 31, 2012	2011	2010
	(In thousands, except per share amounts)		
Net income (loss) (numerator):			
Income (loss) from continuing operations, net of tax	$ 239,055	$ 342,164	$ 255,870
Less: net (income) loss attributable noncontrolling interest	621	1,045	85
Net income (loss) from continuing operations - basic	238,434	341,119	255,785
Add: interest expense on assumed conversion of our 0.94% senior exchangeable notes, net of tax (1)			
Adjusted net income (loss) from continuing operations, net of tax - diluted	238,434	341,119	255,785
Income (loss) from discontinued operations, net of tax	(74,400)	(97,440)	(161,090)
Adjusted net income (loss) attributable to Nabors	$ 164,034	$ 243,679	$ 94,695
Earnings (losses) per share:			
Basic from continuing operations	$ 0.82	$ 1.19	$ 0.90
Basic from discontinued operations	(0.25)	(0.34)	(0.57)
Total Basic	$ 0.57	$ 0.85	$ 0.33
Diluted from continuing operations	$ 0.82	$ 1.17	$ 0.88
Diluted from discontinued operations	(0.26)	(0.34)	(0.55)
Total Diluted	$ 0.56	$ 0.83	$ 0.33
Shares (denominator):			
Weighted-average number of shares outstanding - basic	289,965	287,118	285,145
Net effect of dilutive stock options, warrants and restricted stock awards based on the if-converted method	2,358	5,366	4,851
Assumed conversion of our 0.94% senior exchangeable notes due 2011 (1)			
Weighted-average number of shares outstanding - diluted	292,323	292,484	289,996

(1) At maturity in May 2011, we redeemed the remaining aggregate principal amount of $1.4 billion of our 0.94% senior exchangeable notes. Prior to maturity, we had purchased $1.4 billion par value of these notes in the open market for cash of $1.2 billion. Diluted earnings (losses) per share for 2010 exclude any incremental shares that would have been issuable upon exchange of these notes based on a calculation using our stock price. Our stock price did not exceed the threshold during any period in 2010.

For all periods presented, the computation of diluted earnings (losses) per Nabors share excludes outstanding stock options and warrants with exercise prices greater than the average market price of Nabors common shares, because their inclusion would be anti-dilutive and because they are not considered participating securities. The average number of options and warrants that were excluded from diluted earnings (losses) per share that would potentially dilute earnings per share in the future was 14,200,915, 9,241,543 and 14,004,749 shares during the years ended December 31, 2012, 2011 and 2010, respectively. In any period during which the average market price of

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Nabors common shares exceeds the exercise prices of these stock options and warrants, such stock options and warrants will be included in our diluted earnings (losses) per share computation using the if-converted method of accounting. Restricted stock is included in our basic and diluted earnings (losses) per share computation using the two-class method of accounting in all periods because such stock is considered participating securities.

Note 20 Supplemental Balance Sheet, Income Statement and Cash Flow Information

Accrued liabilities include the following:

	December 31, 2012	December 31, 2011
	(In thousands)	
Accrued compensation	$ 158,095	$ 173,732
Deferred revenue	148,165	172,578
Other taxes payable	58,590	44,652
Workers compensation liabilities	22,645	22,645
Interest payable	90,878	99,869
Due to joint venture partners		6,041
Warranty accrual	6,436	5,237
Litigation reserves	26,782	23,687
Provision for termination payment (1)		100,000
Current liability to discontinued operations	68,961	54,287
Professional fees	2,989	6,413
Current deferred tax liability	10,721	269
Other accrued liabilities	5,118	7,363
	$ 599,380	$ 716,773

(1) Represents a $100 million provision for a termination payment. See Note 3 Impairments and Other Charges for additional discussion.

Investment income (loss) includes the following:

	Year Ended December 31, 2012	2011	2010
		(In thousands)	
Interest and dividend income	$ 7,536	$ 9,930	$ 7,457
Gains (losses) on investments, net	55,601(1)	10,010(2)	(194)(3)
	$ 63,137	$ 19,940	$ 7,263

(1) Includes net unrealized gains of $41.1 million from our trading securities and $14.5 million realized gains from short-term and other long-term investments.

(2) Reflects gain (loss) on sale of debt securities and gains (losses) from our long-term investments of $18.0 million, partially offset by net unrealized losses of $8.0 million from our trading securities.

(3) Includes net unrealized losses of $4.4 million from our trading securities, partially offset by gains on the sale of debt securities and gains from our long-term investments of $4.2 million.

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Losses (gains) on sales and disposals of long-lived assets and other expense (income), net includes the following:

	Year Ended December 31, 2012	2011 (In thousands)	2010
Losses (gains) on sales, disposals and involuntary conversions of long-lived assets	$ (147,488)(1)	$ (11,155)(2)	$ 6,430
Acquisition-related costs		151	7,021
Litigation expenses	5,382	11,301	6,356
Foreign currency transaction losses (gains)	4,787	5,499	18,100
Losses (gains) on derivative instruments	(1,281)	(2,159)	119
Losses (gains) on debt extinguishments (3)		58	7,042
Other losses (gains)	2,090	819	2,170
	$ (136,510)	$ 4,514	$ 47,238

(1) Includes a $160 million gain from the sale of our equity interest in NFR Energy.

(2) Includes a $13.1 million pre-tax gain from our acquisition of Peak during 2011 representing the excess of the estimated fair value of the assets and liabilities over the net carrying value of our previously held equity interest. See Note 5 Acquisitions for additional discussion.

(3) Includes $.1 million and $(7.0) million pre-tax (losses) gains on our purchases of our 0.94% senior exchangeable notes in the open market during 2011 and 2010, respectively.

Supplemental cash flow information includes the following:

	Year Ended December 31, 2012	2011 (In thousands)	2010
Cash paid for income taxes	$ 85,044	$ 53,759	$ 58,574
Cash paid for interest, net of capitalized interest	$ 250,045	$ 208,212	$ 180,731
Acquisitions of businesses:			
Fair value of assets acquired	$	$ 80,585	$ 796,399
Goodwill		8,000	339,992
Liabilities assumed		(10,471)	(332,528)
Common stock of acquired company previously owned			
Subsidiary preferred stock obligation			(69,188)
Gain on acquisition		(13,114)	
Cash paid for acquisitions of businesses		65,000	734,675
Cash acquired in acquisitions of businesses		(9,541)	(1,045)
Cash paid for acquisitions of businesses, net	$	$ 55,459	$ 733,630

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Note 21 Unaudited Quarterly Financial Information

	Year Ended December 31, 2012 Quarter Ended			
	March 31	June 30	September 30	December 31
	(In thousands, except per share amounts)			
Operating revenues and Earnings (losses) from unconsolidated affiliates from continuing operations (1)	$ 1,821,757	$ 1,602,797	$ 1,666,892	$ 1,596,807
Income (loss) from continuing operations, net of tax	$ 142,618	$ (98,653)	$ 65,818	$ 129,272
Income (loss) from discontinued operations, net of tax	(8,795)	24,690	10,826	(101,121)
Less: Net (income) loss attributable to noncontrolling interest	267	1,174	(988)	(1,074)
Net income (loss) attributable to Nabors	$ 134,090	$ (72,789)	$ 75,656	$ 27,077
Earnings (losses) per share: (2)				
Basic from continuing operations	$ 0.50	$ (0.34)	$ 0.22	$ 0.44
Basic from discontinued operations	(0.04)	0.09	0.04	(0.35)
Total Basic	$ 0.46	$ (0.25)	$ 0.26	$ 0.09
Diluted from continuing operations	$ 0.49	$ (0.34)	$ 0.22	$ 0.44
Diluted from discontinued operations	(0.03)	0.09	0.04	(0.35)
Total Diluted	$ 0.46	$ (0.25)	$ 0.26	$ 0.09

	Year Ended December 31, 2011 Quarter Ended			
	March 31	June 30	September 30	December 31
	(In thousands, except per share amounts)			
Operating revenues and Earnings (losses) from unconsolidated affiliates from continuing operations (3)	$ 1,389,842	$ 1,352,950	$ 1,642,227	$ 1,731,979
Income (loss) from continuing operations, net of tax	$ 94,552	$ 70,887	$ 87,190	$ 89,535
Income (loss) from discontinued operations, net of tax	(12,396)	121,167	(12,226)	(193,985)
Less: Net (income) loss attributable to noncontrolling interest	669	394	(708)	(1,400)
Net income (loss) attributable to Nabors	$ 82,825	$ 192,448	$ 74,256	$ (105,850)
Earnings (losses) per share: (2)				
Basic from continuing operations	$ 0.33	$ 0.25	$ 0.30	$ 0.31
Basic from discontinued operations	(0.04)	0.42	(0.04)	(0.68)
Total Basic	$ 0.29	$ 0.67	$ 0.26	$ (0.37)
Diluted from continuing operations	$ 0.33	$ 0.24	$ 0.30	$ 0.30
Diluted from discontinued operations	(0.05)	0.41	(0.05)	(0.66)
Total Diluted	$ 0.28	$ 0.65	$ 0.25	$ (0.36)

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(1) Includes earnings (losses) from unconsolidated affiliates, net, accounted for by the equity method, of $(68.7) million, $(134.3) million, $(99.5) million and $1.2 million, respectively.

(2) Earnings per share is computed independently for each of the quarters presented. Therefore, the sum of the quarterly earnings per share may not equal the total computed for the year.

(3) Includes earnings (losses) from unconsolidated affiliates, net, accounted for by the equity method, of \$16.3 million, \$9.3 million, \$33.7 million and \$(2.7) million, respectively.

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Note 22 Segment Information

At December 31, 2012, we conducted our operations through two business lines:

- Our Drilling & Rig Services business line includes our drilling operations for oil and natural gas wells, on land and offshore, and companies engaged in drilling technology, top drive manufacturing, directional drilling, construction services, and rig instrumentation and software. This business line, consisting of six operating segments, includes U.S. Lower 48 Land Drilling, U.S. Offshore, Alaska, Canada, and International operations. Our U.S. Lower 48 Land Drilling and International operating segments also represent reportable segments based on quantitative thresholds. In addition, our Other Rig Services operating segment combines Canrig Drilling Technology Ltd., Peak Oilfield Services and Ryan Directional Services, Inc. The latter operating segment does not meet the criteria for disclosure, individually or in the aggregate, as a reportable segment.

- Our Completion & Production Services business line includes our well-servicing, fluid logistics, workover operations and our pressure pumping services. This business line, consisting of two operating segments, includes U.S. Production Services and Completion Services, and represents reportable segments.

The accounting policies of the segments are the same as those described in Note 2 - Summary of Significant Accounting Policies. Inter-segment sales are recorded at cost or cost plus a profit margin. We evaluate the performance of our segments based on several criteria, including adjusted income (loss) derived from operating activities.

The following table sets forth financial information with respect to our operating segments:

	Year Ended December 31, 2012	2011 (In thousands)	2010
Operating revenues and Earnings (losses) from unconsolidated affiliates from continuing operations: (1)			
Drilling & Rig Services:			
U.S. Lower 48 Land Drilling	$ 1,860,357	$ 1,698,620	$ 1,294,853
U.S. Offshore	268,986	170,727	123,761
Alaska	147,465	129,894	179,218
Canada	572,616	574,754	389,229
International	1,265,060	1,104,461	1,093,608
Other Rig Services (2)	839,533	674,206	427,154
Subtotal Drilling & Rig Services (3)	4,954,017	4,352,662	3,507,823
Completion & Production Services:			
U.S. Production Services	857,668	701,223	444,665
Completion Services	1,462,767	1,237,306	321,295
Subtotal Completion & Production Services (4)	2,320,435	1,938,529	765,960
Other reconciling items (5)	(586,199)	(174,193)	(106,033)

Total	$	6,688,253	$	6,116,998	$	4,167,750

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	Year Ended December 31, 2012	2011 (In thousands)	2010
Adjusted income (loss) derived from operating activities from continuing operations: (1) (6)			
Drilling & Rig Services:			
U.S. Lower 48 Land Drilling	$ 467,716	$ 414,317	$ 274,215
U.S. Offshore	(305)	843	9,245
Alaska	42,483	27,671	51,896
Canada	96,536	94,637	22,970
International	91,226	123,813	254,744
Other Rig Services (2)	79,061	55,617	42,401
Subtotal Drilling & Rig Services (3)	776,717	716,898	655,471
Completion & Production Services:			
U.S. Production Services	103,659	74,725	31,597
Completion Services	188,518	229,125	66,651
Subtotal Completion & Production Services (4)	292,177	303,850	98,248
Other reconciling items (7)	(150,245)	(153,385)	(104,827)
Total adjusted income (loss) derived from operating activities	$ 918,649	$ 867,363	$ 648,892
U.S. oil and gas joint venture earnings (losses)	(301,801)	59,685	18,657
Interest expense	(251,552)	(256,633)	(272,712)
Investment income (loss)	63,137	19,940	7,263
Gains (losses) on sales and disposals of long-lived assets and other income (expense), net	136,510	(4,514)	(47,238)
Impairments and other charges	(290,260)	(198,072)	(61,292)
Income (loss) from continuing operations before income taxes	274,683	487,769	293,570
Income tax expense (benefit)	32,628	142,605	36,950
Subsidiary preferred stock dividend	3,000	3,000	750
Income (loss) from continuing operations, net of tax	239,055	342,164	255,870
Income (loss) from discontinued operations, net of tax	(74,400)	(97,440)	(161,090)
Net income (loss)	164,655	244,724	94,780
Less: Net (income) loss attributable to noncontrolling interest	(621)	(1,045)	(85)
Net income (loss) attributable to Nabors	$ 164,034	$ 243,679	$ 94,695

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	Year Ended December 31, 2012	2011 (In thousands)	2010
Depreciation and amortization: (1)			
Drilling & Rig Services:			
U.S. Lower 48 Land Drilling	$ 334,555	$ 288,373	$ 241,258
U.S. Offshore	44,328	37,242	37,059
Alaska	27,857	34,989	37,195
Canada	76,663	75,919	74,735
International	330,388	273,315	247,134
Other Rig Services (2)	45,209	34,162	28,452
Subtotal Drilling & Rig Services	859,000	744,000	665,833
Completion & Production Services:			
U.S. Production Services	86,730	78,314	65,561
Completion Services	112,401	102,009	32,204
Subtotal Completion & Production Services	199,131	180,323	97,765
Other reconciling items (5)	(2,614)	(229)	(2,636)
Total depreciation and amortization	$ 1,055,517	$ 924,094	$ 760,962

	Year Ended December 31, 2012	2011 (In thousands)	2010
Capital expenditures and acquisitions of businesses: (9)			
Drilling & Rig Services:			
U.S. Lower 48 Land Drilling	$ 649,078	$ 650,342	$ 294,239
U.S. Offshore	105,245	63,817	23,625
Alaska	4,232	5,582	891
Canada	102,599	95,001	53,834
International	265,249	653,759	365,597
Other Rig Services (2)	39,923	136,515	28,799
Subtotal Drilling & Rig Services	1,166,326	1,605,016	766,985
Completion & Production Services (8)	214,430	451,257	1,009,350
Other reconciling items (7) (10)	52,830	191,462	101,728
Total capital expenditures and acquisitions of businesses	$ 1,433,586	$ 2,247,735	$ 1,878,063

	As of December 31, 2012	2011 (In thousands)	2010
Total assets:			
Drilling & Rig Services:			
U.S. Lower 48 Land Drilling	$ 3,358,339	$ 3,216,803	$ 2,762,362
U.S. Offshore	523,162	402,506	379,292
Alaska	275,969	288,253	313,123
Canada	881,194	962,239	1,065,268
International	3,626,307	3,702,611	3,279,763
Other Rig Services	644,350	720,775	539,373
Subtotal Drilling & Rig Services (10)	9,309,321	9,293,187	8,339,181
Completion & Production Services (8) (11)	2,120,307	2,315,347	1,793,754
Other reconciling items (7)(12)	1,226,394	1,303,606	1,513,634
Total assets	$ 12,656,022	$ 12,912,140	$ 11,646,569

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(1) All periods present the operating activities of our wholly owned oil and gas businesses in the United States, Canada and Colombia, our equity interests in joint ventures in Canada and Colombia and our aircraft logistics operations in Canada as discontinued operations.

(2) Includes our drilling technology and top drive manufacturing, directional drilling, rig instrumentation and software, and construction services. These services represent our other companies that are not aggregated into a reportable operating segment.

(3) Includes earnings (losses), net from unconsolidated affiliates, accounted for using the equity method, of $(3.1) million and $14.6 million for the years ended December 31, 2011 and 2010, respectively.

(4) Includes earnings (losses), net from unconsolidated affiliates, accounted for using the equity method, of $.5 million for the year ended December 31, 2012.

(5) Represents the elimination of inter-segment transactions and earnings (losses), net from the U.S. unconsolidated oil and gas joint venture, accounted for using the equity method until sold in December 2012, of $(301.8) million, $59.7 million and $18.7 million for the years ended December 31, 2012, 2011 and 2010, respectively.

(6) Adjusted income (loss) derived from operating activities is computed by subtracting the sum of direct costs, general and administrative expenses, depreciation and amortization and earnings (losses) from the U.S. oil and gas joint venture from the sum of Operating revenues and Earnings (losses) from unconsolidated affiliates. These amounts should not be used as a substitute for the amounts reported in accordance with GAAP. However, management evaluates the performance of our business units and the consolidated company based on several criteria, including adjusted income (loss) derived from operating activities, because it believes that these financial measures accurately reflect our ongoing profitability. A reconciliation of this non-GAAP measure to income (loss) from continuing operations before income taxes, which is a GAAP measure, is provided in the above table.

(7) Represents the elimination of inter-segment transactions and unallocated corporate expenses, assets and capital expenditures.

(8) Reflects assets allocated to the line of business to conduct its operations. Further allocation to individual operating segments of U.S. Production Services and Completion Services is not available.

(9) Includes the portion of the purchase price of acquisitions allocated to fixed assets and goodwill based on their fair market value.

(10) Includes $59.9 million, $76.9 million and $119.3 million of investments in unconsolidated affiliates accounted for using the equity method as of December 31, 2012, 2011 and 2010, respectively, and $1.9 million of investments in unconsolidated affiliates accounted for using the cost method as of December 31, 2010.

(11) Includes $1.8 million of investments in unconsolidated affiliates accounted for using the equity method as of December 31, 2012.

(12) Includes assets of $377.6 million, $385.4 million and $352.0 million from oil and gas businesses classified as assets held for sale as of December 31, 2012, 2011 and 2010, respectively.

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The following table sets forth financial information with respect to Nabors operations by geographic area:

	Year Ended December 31, 2012	2011 (In thousands)	2010
Operating revenues and Earnings (losses) from unconsolidated affiliates from continuing operations:			
U.S.	$ 4,759,534	$ 4,329,079	$ 2,612,954
Outside the U.S.	1,928,719	1,787,919	1,554,796
	$ 6,688,253	$ 6,116,998	$ 4,167,750
Property, plant and equipment, net:			
U.S.	$ 5,179,578	$ 4,974,239	$ 4,447,388
Outside the U.S.	3,532,510	3,655,707	3,368,031
	$ 8,712,088	$ 8,629,946	$ 7,815,419
Goodwill:			
U.S.	$ 456,463	$ 466,794	$ 459,560
Outside the U.S.	15,863	34,464	34,812
	$ 472,326	$ 501,258	$ 494,372

Note 23 Condensed Consolidating Financial Information

Nabors has fully and unconditionally guaranteed all of the issued public debt securities of Nabors Delaware. The following condensed consolidating financial information is included so that separate financial statements of Nabors Delaware is not required to be filed with the SEC. The condensed consolidating financial statements present investments in both consolidated and unconsolidated affiliates using the equity method of accounting.

The following condensed consolidating financial information presents condensed consolidating balance sheets as of December 31, 2012 and 2011, statements of income (loss) and statements of other comprehensive income (loss) for the years ended December 31, 2012, 2011 and 2010, and the statements of cash flows for the years ended December 31, 2012, 2011 and 2010 of (a) Nabors, parent/guarantor, (b) Nabors Delaware, issuer of public debt securities guaranteed by Nabors, (c) the non-guarantor subsidiaries, (d) consolidating adjustments necessary to consolidate Nabors and its subsidiaries and (e) Nabors on a consolidated basis.

We corrected our 2011 and 2010 condensed consolidating statement of cash flows for classification of changes in intercompany balances between Nabors Delaware (Issuer/Guarantor) and Other Subsidiaries (Non-Guarantors) to present them as cash flows from investing activities rather than cash flows from operating activities. For Nabors Delaware (Issuer / Guarantor), cash used for operating activities increased $78 million and cash provided by investing activities increased by the same amount for the year ended December 31, 2011 while for 2010 cash provided by operating activities decreased $754 million and cash used for investing activities decreased by the same amount. For Other Subsidiaries (Non-Guarantors), cash provided by operating activities increased $78 million and cash used for investing activities increased by the same amount for the year ended December 31, 2011. Cash provided by operating activities increased $754 million and cash used for investing activities increased by the same amount for the year ended December 31, 2010. The impact of these revisions is not material to the related financial statements taken as a whole.

Certain reclassifications to intercompany payable and receivable balances in the condensed consolidating balance sheet have been made to the prior period to conform to current period presentation, with no effect on our consolidated financial position, results of operations or cash flows.

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Condensed Consolidating Balance Sheets

	Nabors (Parent/ Guarantor)	Nabors Delaware (Issuer/ Guarantor)	December 31, 2012 Other Subsidiaries (Non- Guarantors)	Consolidating Adjustments	Total
			(In thousands)		
			ASSETS		
Current assets:					
Cash and cash equivalents	$ 1,639	$ 106,778	$ 416,505	$	$ 524,922
Short-term investments			253,282		253,282
Assets held for sale			383,857		383,857
Accounts receivable, net			1,382,623		1,382,623
Inventory			251,133		251,133
Deferred income taxes			110,480		110,480
Other current assets	50		226,510		226,560
Total current assets	1,689	106,778	3,024,390		3,132,857
Long-term investments			4,269		4,269
Property, plant and equipment, net		37,300	8,674,788		8,712,088
Goodwill			472,326		472,326
Intercompany receivables	174,948	1,690,636	670,404	(2,535,988)	
Investment in unconsolidated affiliates	5,769,518	5,129,458	395,246	(11,232,532)	61,690
Other long-term assets		31,904	240,888		272,792
Total assets	$ 5,946,155	$ 6,996,076	$ 13,482,311	$ (13,768,520)	$ 12,656,022
			LIABILITIES AND EQUITY		
Current liabilities:					
Current portion of long-term debt	$	$	$ 364	$	$ 364
Trade accounts payable	116	23	498,871		499,010
Accrued liabilities	1,110	91,520	540,378		633,008
Total current liabilities	1,226	91,543	1,039,613		1,132,382
Long-term debt		4,379,263	73		4,379,336
Other long-term liabilities		30,983	487,681		518,664
Deferred income taxes		(24,906)	624,241		599,335
Intercompany payable		2,535,988		(2,535,988)	
Total liabilities	1,226	7,012,871	2,151,608	(2,535,988)	6,629,717
Subsidiary preferred stock			69,188		69,188
Shareholders equity	5,944,929	(16,795)	11,249,327	(11,232,532)	5,944,929
Noncontrolling interest			12,188		12,188
Total equity	5,944,929	(16,795)	11,261,515	(11,232,532)	5,957,117
Total liabilities and equity	$ 5,946,155	$ 6,996,076	$ 13,482,311	$ (13,768,520)	$ 12,656,022

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	Nabors (Parent/ Guarantor)	Nabors Delaware (Issuer/ Guarantor)	Other Subsidiaries (Non- Guarantors)	Consolidating Adjustments	Total
			December 31, 2011 (In thousands)		
ASSETS					
Current assets:					
Cash and cash equivalents	$ 203	$ 21	$ 398,351	$	$ 398,575
Short-term investments			140,914		140,914
Assets held for sale			401,500		401,500
Accounts receivable, net			1,576,555		1,576,555
Inventory			272,852		272,852
Deferred income taxes			127,874		127,874
Other current assets	50	671	169,323		170,044
Total current assets	253	692	3,087,369		3,088,314
Long-term investments			11,124		11,124
Property, plant and equipment, net		40,792	8,589,154		8,629,946
Goodwill			501,258		501,258
Intercompany receivables	164,760	1,620,365	214,640	(1,999,765)	
Investment in unconsolidated affiliates	5,429,029	6,084,868	1,843,654	(12,986,530)	371,021
Other long-term assets		32,037	278,440		310,477
Total assets	$ 5,594,042	$ 7,778,754	$ 14,525,639	$ (14,986,295)	$ 12,912,140
LIABILITIES AND EQUITY					
Current liabilities:					
Current portion of long-term debt	$	$ 274,604	$ 722	$	$ 275,326
Trade accounts payable	42	23	782,688		782,753
Accrued liabilities	6,185	100,101	638,197		744,483
Total current liabilities	6,227	374,728	1,421,607		1,802,562
Long-term debt		4,297,500	50,990		4,348,490
Other long-term liabilities		32,303	71,375		292,758
Deferred income taxes		11,221	786,704		797,925
Intercompany payable		1,999,765		(1,999,765)	
Total liabilities	6,227	6,715,517	2,519,756	(1,999,765)	7,241,735
Subsidiary preferred stock			69,188		69,188
Shareholders equity	5,587,815	1,063,237	11,923,293	(12,986,530)	5,587,815
Noncontrolling interest			13,402		13,402
Total equity	5,587,815	1,063,237	11,936,695	(12,986,530)	5,601,217
Total liabilities and equity	$ 5,594,042	$ 7,778,754	$ 14,525,639	$ (14,986,295)	$ 12,912,140

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Condensed Consolidating Statements of Income (Loss)

	Year Ended December 31, 2012				
	Nabors (Parent/ Guarantor)	Nabors Delaware (Issuer/ Guarantor)	Other Subsidiaries (Non-Guarantors)	Consolidating Adjustments	Total
	(In thousands)				
Revenues and other income:					
Operating revenues	$	$	$ 6,989,573	$	$ 6,989,573
Earnings from unconsolidated affiliates			(301,320)		(301,320)
Earnings (losses) from consolidated affiliates	172,406	(107,240)	(214,605)	149,439	
Investment income (loss)		43	63,094		63,137
Intercompany interest income		69,145		(69,145)	
Total revenues and other income	172,406	(38,052)	6,536,742	80,294	6,751,390
Costs and other deductions:					
Direct costs			4,483,320		4,483,320
General and administrative expenses	7,141	458	526,577	(1,608)	532,568
Depreciation and amortization		3,610	1,051,907		1,055,517
Interest expense		268,904	(17,352)		251,552
Intercompany interest expense			69,145	(69,145)	
Losses (gains) on sales of long-lived assets and other expense (income), net	1,231	(2,451)	(136,898)	1,608	(136,510)
Impairments and other charges			290,260		290,260
Total costs and other deductions	8,372	270,521	6,266,959	(69,145)	6,476,707
Income from continuing operations before income taxes	164,034	(308,573)	269,783	149,439	274,683
Income tax expense (benefit)		(74,493)	107,121		32,628
Subsidiary preferred stock dividend			3,000		3,000
Income (loss) from continuting operations, net of tax	164,034	(234,080)	159,662	149,439	239,055
Income (loss) from discontinued operations, net of tax			(74,400)		(74,400)
Net income (loss) attributable to Nabors	164,034	(234,080)	85,262	149,439	164,655
Less: Net (income) loss attributable to noncontrolling interest			(621)		(621)
Net income (loss)	$ 164,034	$ (234,080)	$ 84,641	$ 149,439	$ 164,034

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	Year Ended December 31, 2011				
	Nabors (Parent/ Guarantor)	Nabors Delaware (Issuer/ Guarantor)	Other Subsidiaries (Non-Guarantors) (In thousands)	Consolidating Adjustments	Total
Revenues and other income:					
Operating revenues	$	$	$ 6,060,351	$	$ 6,060,351
Earnings from unconsolidated affiliates			56,647		56,647
Earnings (losses) from consolidated affiliates	256,245	214,308	107,536	(578,089)	
Investment income (loss)	4	68	19,868		19,940
Intercompany interest income		69,437		(69,437)	
Total revenues and other income	256,249	283,813	6,244,402	(647,526)	6,136,938
Costs and other deductions:					
Direct costs			3,775,964		3,775,964
General and administrative expenses	11,970	348	478,174	(600)	489,892
Depreciation and amortization		3,532	920,562		924,094
Interest expense		278,657	(22,024)		256,633
Intercompany interest expense			69,437	(69,437)	
Losses (gains) on sales of long-lived assets and other expense (income), net	600	(1,904)	5,218	600	4,514
Impairments and other charges			198,072		198,072
Total costs and other deductions	12,570	280,633	5,425,403	(69,437)	5,649,169
Income from continuing operations before income taxes	243,679	3,180	818,999	(578,089)	487,769
Income tax expense (benefit)		(78,118)	220,723		142,605
Subsidiary preferred stock dividend			3,000		3,000
Income (loss) from continuting operations, net of tax	243,679	81,298	595,276	(578,089)	342,164
Income (loss) from discontinued operations, net of tax			(97,440)		(97,440)
Net income (loss) attributable to Nabors	243,679	81,298	497,836	(578,089)	244,724
Less: Net (income) loss attributable to noncontrolling interest			(1,045)		(1,045)
Net income (loss)	$ 243,679	$ 81,298	$ 496,791	$ (578,089)	$ 243,679

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	Year Ended December 31, 2010				
	Nabors (Parent/ Guarantor)	Nabors Delaware (Issuer/ Guarantor)	Other Subsidiaries (Non- Guarantors) (In thousands)	Consolidating Adjustments	Total
Revenues and other income:					
Operating revenues	$	$	$ 4,134,483	$	$ 4,134,483
Earnings from unconsolidated affiliates			33,267		33,267
Earnings (losses) from consolidated affiliates	68,749	(183,242)	(316,657)	431,150	
Investment income (loss)	15		7,248		7,263
Intercompany interest income		72,435		(72,435)	
Total revenues and other income	68,764	(110,807)	3,858,341	358,715	4,175,013
Costs and other deductions:					
Direct costs			2,400,519		2,400,519
General and administrative expenses	9,165	445	330,067	(957)	338,720
Depreciation and amortization		3,303	757,659		760,962
Interest expense		283,396	(10,684)		272,712
Intercompany interest expense			72,435	(72,435)	
Losses (gains) on sales of long-lived assets and other expense (income), net	(35,096)	42,504	38,873	957	47,238
Impairments and other charges			61,292		61,292
Total costs and other deductions	(25,931)	329,648	3,650,161	(72,435)	3,881,443
Income from continuing operations before income taxes	94,695	(440,455)	208,180	431,150	293,570
Income tax expense (benefit)		(95,168)	132,118		36,950
Subsidiary preferred stock dividend			750		750
Income (loss) from continuting operations, net of tax	94,695	(345,287)	75,312	431,150	255,870
Income (loss) from discontinued operations, net of tax			(161,090)		(161,090)
Net income (loss) attributable to Nabors	94,695	(345,287)	(85,778)	431,150	94,780
Less: Net (income) loss attributable to noncontrolling interest			(85)		(85)
Net income (loss)	$ 94,695	$ (345,287)	$ (85,863)	$ 431,150	$ 94,695

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Condensed Consolidating Statements of Other Comprehensive Income

	Year Ended December 31, 2012				
	Nabors (Parent/ Guarantor)	Nabors Delaware (Issuer/ Guarantor)	Other Subsidiaries (Non- Guarantors) (In thousands)	Consolidating Adjustments	Total
Net income (loss) attributable to Nabors	$ 164,034	$ (234,080)	$ 84,641	$ 149,439	$ 164,034
Other comprehensive income (loss) before taxes					
Translation adjustment attributable to Nabors	21,073	(88)	20,987	(20,899)	21,073
Unrealized gains/(losses) on marketable securities:					
Unrealized gains/(losses) on marketable securities	98,138	133	98,271	(98,404)	98,138
Less: reclassification adjustment for (gains)/losses on marketable securities	(13,405)	(11,488)	(24,893)	36,381	(13,405)
Unrealized gains/(losses) on marketable securities	84,733	(11,355)	73,378	(62,023)	84,733
Pension liability amortization and adjustment	(324)	(324)	(648)	972	(324)
Unrealized gains/(losses) and amortization of (gains)/losses on cash flow hedges	702	702	702	(1,404)	702
Other comprehensive income (loss) before taxes	106,184	(11,065)	94,419	(83,354)	106,184
Income tax expense (benefit) related to items of other comprehensive income (loss)	(4,147)	(4,147)	(8,533)	12,680	(4,147)
Other comprehensive income (loss), net of tax	110,331	(6,918)	102,952	(96,034)	110,331
Comprehensive income (loss) attributable to Nabors	274,365	(240,998)	187,593	53,405	274,365
Net income (loss) attributable to noncontrolling interest	621		621	(621)	621
Translation adjustment to noncontrolling interest	311		311	(311)	311
Comprehensive income (loss) attributable to noncontrolling interest	932		932	(932)	932
Comprehensive income (loss)	$ 275,297	$ (240,998)	$ 188,525	$ 52,473	$ 275,297

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	Year Ended December 31, 2011				
	Nabors (Parent/ Guarantor)	Nabors Delaware (Issuer/ Guarantor)	Other Subsidiaries (Non- Guarantors)	Consolidating Adjustments	Total
	(In thousands)				
Net income (loss) attributable to Nabors	$ 243,679	$ 81,298	$ 496,791	$ (578,089)	$ 243,679
Other comprehensive income (loss) before taxes					
Translation adjustment attributable to Nabors	(20,257)	(5,511)	(25,768)	31,279	(20,257)
Unrealized gains/(losses) on marketable securities:					
Unrealized gains/(losses) on marketable securities	5,356	226	5,582	(5,808)	5,356
Less: reclassification adjustment for (gains)/losses on marketable securities	(3,036)		(3,036)	3,036	(3,036)
Unrealized gains/(losses) on marketable securities	2,320	226	2,546	(2,772)	2,320
Pension liability amortization and adjustment	(5,391)	(5,391)	(10,782)	16,173	(5,391)
Unrealized gains/(losses) and amortization of (gains)/losses on cash flow hedges	763	763	763	(1,526)	763
Other comprehensive income (loss) before taxes	(22,565)	(9,913)	(33,241)	43,154	(22,565)
Income tax expense (benefit) related to items of other comprehensive income (loss)	(1,777)	(1,777)	(3,793)	5,570	(1,777)
Other comprehensive income (loss), net of tax	(20,788)	(8,136)	(29,448)	37,584	(20,788)
Comprehensive income (loss) attributable to Nabors	222,891	73,162	467,343	(540,505)	222,891
Net income (loss) attributable to noncontrolling interest	1,045		1,045	(1,045)	1,045
Translation adjustment to noncontrolling interest	(185)		(185)	185	(185)
Comprehensive income (loss) attributable to noncontrolling interest	860		860	(860)	860
Comprehensive income (loss)	$ 223,751	$ 73,162	$ 468,203	$ (541,365)	$ 223,751

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	Year Ended December 31, 2010				
	Nabors (Parent/ Guarantor)	Nabors Delaware (Issuer/ Guarantor)	Other Subsidiaries (Non- Guarantors) (In thousands)	Consolidating Adjustments	Total
Net income (loss) attributable to Nabors	$ 94,695	$ (345,287)	$ (85,863)	$ 431,150	$ 94,695
Other comprehensive income (loss) before taxes					
Translation adjustment attributable to Nabors	60,897	(3,113)	57,784	(54,671)	60,897
Unrealized gains/(losses) on marketable securities:					
Unrealized gains/(losses) on marketable securities	278	19,390	19,668	(39,058)	278
Less: reclassification adjustment for (gains)/losses on marketable securities	(1,694)	(1,808)	(3,502)	5,310	(1,694)
Unrealized gains/(losses) on marketable securities	(1,416)	17,582	16,166	(33,748)	(1,416)
Pension liability amortization and adjustment	(376)	(376)	(752)	1,128	(376)
Unrealized gains/(losses) and amortization of (gains)/losses on cash flow hedges	(5,282)	(5,282)	(5,282)	10,564	(5,282)
Other comprehensive income (loss) before taxes	53,823	8,811	67,916	(76,727)	53,823
Income tax expense (benefit) related to items of other comprehensive income (loss)	4,477	4,477	11,073	(15,550)	4,477
Other comprehensive income (loss), net of tax	49,346	4,334	56,843	(61,177)	49,346
Comprehensive income (loss) attributable to Nabors	144,041	(340,953)	(29,020)	369,973	144,041
Net income (loss) attributable to noncontrolling interest	85		85	(85)	85
Translation adjustment to noncontrolling interest	723		723	(723)	723
Comprehensive income (loss) attributable to noncontrolling interest	808		808	(808)	808
Comprehensive income (loss)	$ 144,849	$ (340,953)	$ (28,212)	$ 369,165	$ 144,849

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Condensed Consolidating Statements of Cash Flows

	Year Ended December 31, 2012				
	Nabors (Parent/ Guarantor)	Nabors Delaware (Issuer/ Guarantor)	Other Subsidiaries (Non-Guarantors) (In thousands)	Consolidating Adjustments	Total
Net cash provided by (used for) operating activities	$ 7,253	$ 39,708	$ 1,546,250	$ (30,506)	$ 1,562,705
Cash flows from investing activities:					
Purchases of investments			(949)		(949)
Sales and maturities of investments			31,944		31,944
Cash paid for acquisition of businesses, net	(35)			35	
Proceeds from sale of unconsolidated affiliates			150,000		150,000
Distribution of proceeds from asset sales of unconsolidated affiliates			9,529		9,529
Investment in unconsolidated affiliates			(1,325)		(1,325)
Capital expenditures			(1,518,628)		(1,518,628)
Proceeds from sales of assets and insurance claims			149,801		149,801
Cash paid for investments in consolidated affiliates					
Changes in intercompany balances		274,482	(274,482)		
Net cash provided by (used for) investing activities	(35)	274,482	(1,454,110)	35	(1,179,628)
Cash flows from financing activities:					
Increase (decrease) in cash overdrafts			1,612		1,612
Debt issuance costs		(3,433)			(3,433)
Proceeds from revolving credit facilities		710,000			710,000
Proceeds from (payments for) issuance of common shares	(3,622)		(3)		(3,625)
Reduction in long-term debt		(224,997)	(51,261)		(276,258)
Reduction in revolving credit facilities		(680,000)			(680,000)
Purchase of restricted stock	(2,160)				(2,160)
Tax benefit related to share-based awards			(263)		(263)
Proceeds from parent contributions			35	(35)	
Cash dividends paid		(9,003)	(21,503)	30,506	
Net cash (used for) provided by financing activities	(5,782)	(207,433)	(71,383)	30,471	(254,127)
Effect of exchange rate changes on cash and cash equivalents			(2,603)		(2,603)
Net increase (decrease) in cash and cash equivalents	1,436	106,757	18,154		126,347
Cash and cash equivalents, beginning of period	203	21	398,351		398,575
Cash and cash equivalents, end of period	$ 1,639	$ 106,778	$ 416,505	$	$ 524,922

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	Year Ended December 31, 2011				
	Nabors (Parent/ Guarantor)	Nabors Delaware (Issuer/ Guarantor)	Other Subsidiaries (Non-Guarantors) (In thousands)	Consolidating Adjustments	Total
Net cash provided by (used for) operating activities	$ 6,612	$ (109,125)	$ 1,559,000	$	$ 1,456,487
Cash flows from investing activities:					
Purchases of investments			(11,746)		(11,746)
Sales and maturities of investments			39,063		39,063
Cash paid for acquisition of businesses, net			(55,459)		(55,459)
Distribution of proceeds from asset sales of unconsolidated affiliates			142,984		142,984
Investment in unconsolidated affiliates			(112,262)		(112,262)
Capital expenditures			(2,042,617)		(2,042,617)
Proceeds from sales of assets and insurance claims			180,558		180,558
Cash paid for investments in consolidated affiliates	(26,235)	(65,000)		91,235	
Changes in intercompany balances		77,947	(77,947)		
Net cash provided by (used for) investing activities	(26,235)	12,947	(1,937,426)	91,235	(1,859,479)
Cash flows from financing activities:					
Increase (decrease) in cash overdrafts			6,375		6,375
Proceeds from issuance of long-term debt		697,578			697,578
Debt issuance costs		(7,141)			(7,141)
Proceeds from revolving credit facilities		1,510,000	50,000		1,560,000
Proceeds from issuance of common shares	11,605				11,605
Reduction in long-term debt		(1,404,246)	(35)		(1,404,281)
Reduction in revolving credit facilities		(700,000)			(700,000)
Repurchase of equity component of convertible debt		(12)			(12)
Purchase of restricted stock	(2,626)				(2,626)
Tax benefit related to share-based awards			1,747		1,747
Proceeds from parent contributions			91,235	(91,235)	
Net cash (used for) provided by financing activities	8,979	96,179	149,322	(91,235)	163,245
Effect of exchange rate changes on cash and cash equivalents			(3,380)		(3,380)
Net increase (decrease) in cash and cash equivalents	(10,644)	1	(232,484)		(243,127)
Cash and cash equivalents, beginning of period	10,847	20	630,835		641,702
Cash and cash equivalents, end of period	$ 203	$ 21	$ 398,351	$	$ 398,575

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	Year Ended December 31, 2010				
	Nabors (Parent/ Guarantor)	Nabors Delaware (Issuer/ Guarantor)	Other Subsidiaries (Non-Guarantors)	Consolidating Adjustments	Total
			(In thousands)		
Net cash provided by (used for) operating activities	$ 115,179	$ 3,697	$ 1,258,108	$ (270,000)	$ 1,106,984
Cash flows from investing activities:					
Purchases of investments			(34,147)		(34,147)
Sales and maturities of investments			34,613		34,613
Cash paid for acquisition of businesses, net			(733,630)		(733,630)
Investment in unconsolidated affiliates			(40,936)		(40,936)
Capital expenditures			(930,277)		(930,277)
Proceeds from sales of assets and insurance claims			31,072		31,072
Cash paid for investments in consolidated affiliates	(122,300)	(1,027,134)		1,149,434	
Changes in intercompany balances		753,648	(753,648)		
Net cash provided by (used for) investing activities	(122,300)	(273,486)	(2,426,953)	1,149,434	(1,673,305)
Cash flows from financing activities:					
Increase (decrease) in cash overdrafts			(6,298)		(6,298)
Proceeds from issuance of long-term debt		696,948			696,948
Debt issuance costs		(8,934)			(8,934)
Payments for hedge transactions		(5,667)			(5,667)
Proceeds from revolving credit facilities		600,000			600,000
Proceeds from issuance of common shares	8,201				8,201
Reduction in long-term debt		(274,095)	(124,419)		(398,514)
Reduction in revolving credit facilities		(600,000)			(600,000)
Repurchase of equity component of convertible debt		(4,712)			(4,712)
Settlement of call options and warrants, net		1,134			1,134
Purchase of restricted stock	(1,935)				(1,935)
Tax benefit related to share-based awards			31		31
Cash dividends paid		(135,000)	(135,000)	270,000	
Proceeds from parent contributions			1,149,434	(1,149,434)	
Net cash (used for) provided by financing activities	6,266	269,674	883,748	(879,434)	280,254
Effect of exchange rate changes on cash and cash equivalents			(46)		(46)
Net increase (decrease) in cash and cash equivalents	(855)	(115)	(285,143)		(286,113)
Cash and cash equivalents, beginning of period	11,702	135	915,978		927,815
Cash and cash equivalents, end of period	$ 10,847	$ 20	$ 630,835	$	$ 641,702

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Supplemental Information on Oil and Gas Exploration and Production Activities (unaudited)

We own certain mineral rights in connection with our exploration for and the acquisition, development and production of natural gas, oil and natural gas liquids in the United States and the Canadian provinces of Alberta and British Columbia.

The estimates of net proved oil and gas reserves as of December 31, 2012 were based on reserve reports prepared by independent petroleum engineers. AJM Deloitte prepared reports of estimated proved oil and gas reserves for our wholly owned assets in Canada. Cawley, Gillespie & Associates, Inc. prepared reports of estimated proved oil reserves for our wholly owned assets located in the Eagle Ford Shale, Texas. DeGolyer and MacNaughton Corp. prepared reports of estimated proved oil and gas reserves for our wholly owned assets in Alaska.

The estimates of net proved oil and gas reserves as of December 31, 2011 were based on reserve reports prepared by independent petroleum engineers. AJM Deloitte prepared reports of estimated proved oil and gas reserves for our wholly owned assets in Canada. Miller and Lents, Ltd. prepared reports of estimated proved oil and gas reserves for our wholly owned assets and interests in oil and natural gas properties located in the United States. Cawley, Gillespie & Associates, Inc. prepared reports of estimated proved oil reserves for our wholly owned assets located in the Eagle Ford Shale and Giddings field in Grimes County, Texas.

The estimates of net proved oil and natural gas reserves as of December 31, 2010 were based on reserve reports prepared by the following independent petroleum engineers. AJM Petroleum Consultants prepared reports of estimated proved oil and gas reserves for our wholly owned assets in Canada; Miller and Lents, Ltd. prepared reports of estimated proved oil and gas reserves for our wholly owned assets and interests in oil and natural gas properties located in the United States; Netherland, Sewell & Associates, Inc., prepared reports of estimated proved oil reserves for certain properties located in the Cat Canyon and West Cat Canyon Fields in Santa Barbara County, California; and Lonquist & Co., LLC prepared reports of estimated proved oil and gas reserves for our wholly owned assets in Colombia.

The following supplementary information includes our results of operations for oil and gas production activities; capitalized costs related to oil and gas producing activities; and costs incurred in oil and gas property acquisition, exploration and development. Supplemental information is also provided for the estimated quantities of proved oil and gas reserves; the standardized measure of discounted future net cash flows associated with proved oil and gas reserves; and a summary of the changes in the standardized measure of discounted future net cash flows associated with proved oil and gas reserves.

Results of Operations

Results of operations of oil and gas activities are included in discontinued operations, except those of our former unconsolidated U.S. oil and joint venture. Net revenues from production include only the revenues from the production and sale of natural gas, oil, and natural gas liquids. Production costs are those incurred to operate and maintain wells and related equipment and facilities used in oil and gas operations. Exploration expenses include dry-hole costs, geological and geophysical expenses, and the costs of retaining undeveloped leaseholds. Income tax expense is calculated by applying the current statutory tax rates to the revenues after deducting costs, which include depreciation, depletion and amortization (DD&A) allowances, after giving effect to permanent differences. The results of operations exclude general office overhead and interest expense attributable to oil and gas activities.

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	United States	Canada	Colombia	Total
		(In thousands)		
Results of Operations				
For the year ended December 31, 2010:				
Consolidated Subsidiaries				
Revenue	$ 19,180	$ 11,276	$ 16,619	$ 47,075
Production costs	8,510	7,965	7,918	24,393
Exploration expenses			39,047	39,047
Depreciation and depletion	20,092	5,424	3,737	29,253
Impairment of oil and gas properties	110,165			110,165
Related income tax expense (benefit)	(15,856)	(3,078)	610	(18,324)
Results of producing activities for consolidated subsidiaries	$ (103,731)	$ 965	$ (34,693)	$ (137,459)
Equity Companies (1)				
Revenue	$ 64,736	$ 6,038	$ 20,176	$ 90,950
Production costs	18,460	9,036	9,174	36,670
Depreciation and depletion	24,221	6,033	7,058	37,312
Impairment of oil and gas properties	851			851
Realized gain on derivative instrument	(25,424)	(2,543)		(27,967)
Related income tax expense (benefit) (2)				
Results of producing activities for equity subsidiaries	$ 46,628	$ (6,488)	$ 3,944	$ 44,084
Total results of operations	$ (57,103)	$ (5,523)	$ (30,749)	$ (93,375)
For the year ended December 31, 2011:				
Consolidated Subsidiaries				
Revenue	$ 25,684	$ 7,046	$ 12,378	$ 45,108
Production costs	12,682	27,432(3)	3,704	43,818
Exploration expenses	23,768	3,324	122	27,214
Depreciation and depletion	22,350	104	949	23,403
Impairment of oil and gas properties	71,392	183,654		255,046
Loss (gain) on disposition	(6,642)		(39,599)	(46,241)
Related income tax expense (benefit)	(38,707)	(54,979)	15,577	(78,109)
Results of producing activities for consolidated subsidiaries	$ (59,159)	$ (152,489)	$ 31,625	$ (180,023)
Equity Companies (1)				
Revenue	$ 98,933	$ 1,335	$ 26,730	$ 126,998
Production costs	27,790	4,600	10,598	42,988
Depreciation and depletion	39,564	1,032	9,806	50,402
Impairment of oil and gas properties	15,624			15,624
Realized gain on derivative instrument	(33,969)	(84)		(34,053)
Loss (gain) on acquisitions/dispositions	(49,484)		(95,301)	(144,785)
Related income tax expense (benefit) (2)			6,055	6,055
Results of producing activities for equity subsidiaries	$ 99,408	$ (4,213)	$ 95,572	$ 190,767
Total results of operations	$ 40,249	$ (156,702)	$ 127,197	$ 10,744

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	United States	Canada	Colombia	Total
		(In thousands)		
Results of Operations				
For the year ended December 31, 2012:				
Consolidated Subsidiaries				
Revenue	$ 24,805	$ 4,741	$ 435	$ 29,981
Production costs	8,959	5,842	106	14,907
Exploration expenses	1,245	160	2,343	3,748
Depreciation and depletion	89	2,308	13	2,410
Impairment of oil and gas properties	29,314	127,766		157,080
Loss (gain) on disposition	(2,302)		(47,060)(5)	(49,362)
Related income tax expense (benefit)	(8,092)	(32,834)		(40,926)
Results of producing activities for consolidated subsidiaries	$ (4,408)	$ (98,501)	$ 45,033	$ (57,876)
Equity Companies (1)				
Revenue	$ 80,607	$	$	$ 80,607
Production costs	32,192			32,192
Depreciation and depletion	39,500			39,500
Impairment of oil and gas properties	325,573(4)			325,573
Realized gain on derivative instrument	(50,167)			(50,167)
Related income tax expense (benefit) (2)				
Results of producing activities for equity subsidiaries	$ (266,491)	$	$	$ (266,491)
Total results of operations	$ (270,899)	$ (98,501)	$ 45,033	$ (324,367)

(1) Represents our proportionate share of interests in our equity companies for the applicable year.

(2) Equity companies are pass-through entities for tax purposes.

(3) Includes $24.2 million of transportation costs from pipeline commitments during 2011.

(4) Includes our proportionate share of full-cost ceiling test writedowns.

(5) Includes our gain on disposition of Colombia properties in April 2012.

Capitalized Cost

Capitalized costs include the cost of properties, equipment and facilities for oil and gas-producing activities. Capitalized costs for proved properties include costs for oil and gas leaseholds where proved reserves have been identified, development wells, and related equipment and facilities, including development wells in progress. Capitalized costs for unproved properties include costs for acquiring oil and gas leaseholds where no proved reserves have been identified, including costs of exploratory wells that are in the process of drilling or for active completion, and costs of exploratory wells suspended or waiting for completion.

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	United States	Canada	Colombia	Total
		(In thousands)		
Capitalized Costs				
For the year ended December 31, 2010:				
Consolidated Subsidiaries				
Property acquisition costs, proved	$ 480,618	$ 62,109	$ 57,251	$ 599,978
Property acquisition costs, unproved	136,625	89,785	1,174	227,584
Total acquisition costs	617,243	151,894	58,425	827,562
Accumualted depreciation and amortization	(463,330)	(7,344)	(3,782)	(474,456)
Net capitalized costs for consolidated subsidiaries	$ 153,913	$ 144,550	$ 54,643	$ 353,106
Equity Companies (1)				
Property acquisition costs, proved	$ 749,515	$ 78,224	$ 98,629	$ 926,368
Property acquisition costs, unproved	108,541	28,884	883	138,308
Total acquisition costs	858,056	107,108	99,512	1,064,676
Accumualted depreciation and amortization	(460,622)	(72,338)	(31,825)	(564,785)
Net capitalized costs for equity companies	$ 397,434	$ 34,770	$ 67,687	$ 499,891
For the year ended December 31, 2011:				
Consolidated Subsidiaries				
Property acquisition costs, proved	$ 587,385	$ 101,402	$	$ 688,787
Property acquisition costs, unproved	101,611	92,750	23,767	218,128
Total acquisition costs	688,996	194,152	23,767	906,915
Accumualted depreciation and amortization	(539,380)	(28,838)	(741)	(568,959)
Net capitalized costs for consolidated subsidiaries	$ 149,616	$ 165,314	$ 23,026	$ 337,956
Equity Companies (1)				
Property acquisition costs, proved	$ 1,141,393	$	$	$ 1,141,393
Property acquisition costs, unproved	103,657			103,657
Total acquisition costs	1,245,050			1,245,050
Accumualted depreciation and amortization	(512,503)			(512,503)
Net capitalized costs for equity companies	$ 732,547	$	$	$ 732,547

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	United States	Canada	Colombia	Total
		(In thousands)		
Capitalized Costs				
For the year ended December 31, 2012:				
Consolidated Subsidiaries				
Property acquisition costs, proved	$ 114,427	$ 62,048	$	$ 176,475
Property acquisition costs, unproved	91,219	83,455		174,674
Total acquisition costs	205,646	145,503		351,149
Accumualted depreciation and amortization	(23,949)	(29,560)		(53,509)
Net capitalized costs for consolidated subsidiaries	$ 181,697	$ 115,943	$	$ 297,640
Equity Companies (2)				

(1) Represents our proportionate share of interests in our equity companies for the applicable year.

(2) As of December 31, 2012, we do not have any equity companies with oil and gas assets.

Costs Incurred in Oil and Gas Property Acquisitions, Exploration and Development

Amounts reported as costs incurred include both capitalized costs and costs charged to expense during 2012, 2011 and 2010, respectively, for oil and gas property acquisition, exploration and development activities. Costs incurred also include new asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligations resulting from changes to cost estimates during the year. Exploration costs include the costs of drilling and equipping successful exploration wells, as well as dry-hole costs, geological and geophysical expenses, and the costs of retaining undeveloped leaseholds. Development costs include the costs of drilling and equipping development wells, and construction of related production facilities.

	United States	Canada	Colombia	Total
		(In thousands)		
Costs incurred in property acquisitions, exploration and development activities				
For the year ended December 31, 2010:				
Consolidated Subsidiaries				
Property acquisition costs, proved	$ 25,080	$	$	$ 25,080
Property acquisition costs, unproved	25,202		1,000	26,202
Exploration costs	8,199		33,599	41,798
Development costs	19,118	3,876		22,994
Asset retirement costs			770	770
Total costs incurred for consolidated subsidiaries	$ 77,599	$ 3,876	$ 35,369	$ 116,844
Equity Companies (1)				
Property acquisition costs, proved	$ 29,975	$	$	$ 29,975
Property acquisition costs, unproved	34,207			34,207
Exploration costs	108		29,927	30,035
Development costs	118,828	1,056	11,805	131,689

Asset retirement costs		296				(104)		192
Total costs incurred for equity companies	$	183,414	$	1,056	$	41,628	$	226,098

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	United States	Canada	Colombia	Total
		(In thousands)		
Costs incurred in property acquisitions, exploration and development activities				
For the year ended December 31, 2011:				
Consolidated Subsidiaries				
Property acquisition costs, proved	$ 23,051	$ 7,748	$	$ 30,799
Property acquisition costs, unproved	37,272	26,099		63,371
Exploration costs	49,156		122	49,278
Development costs	43,780	184	19,605	63,569
Asset retirement costs	496	750	254	1,500
Total costs incurred for consolidated subsidiaries	$ 153,755	$ 34,781	$ 19,981	$ 208,517
Equity Companies (1)				
Property acquisition costs, proved	$ 232,410	$	$	$ 232,410
Property acquisition costs, unproved	14,268		4,395	18,663
Exploration costs	252			252
Development costs	136,711			136,711
Asset retirement costs	2,834			2,834
Total costs incurred for equity companies	$ 386,475	$	$ 4,395	$ 390,870

	United States	Canada	Colombia	Total
		(In thousands)		
Costs incurred in property acquisitions, exploration and development activities				
For the year ended December 31, 2012:				
Consolidated Subsidiaries				
Property acquisition costs, proved	$	$	$	$
Property acquisition costs, unproved				
Exploration costs	27,994	190	13,181	41,365
Development costs	64,805	623		65,428
Asset retirement costs	89	162	13	264
Total costs incurred for consolidated subsidiaries	$ 92,888	$ 975	$ 13,194	$ 107,057
Equity Companies (1)				
Property acquisition costs, proved	$ 1,420	$	$	$ 1,420
Property acquisition costs, unproved				
Exploration costs	31,411			31,411
Development costs	24,355			24,355
Asset retirement costs	127			127
Total costs incurred for equity companies	$ 57,313	$	$	$ 57,313

(1) Represents our proportionate share of interests in equity companies for the applicable year.

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Oil and Gas Reserves

The reserve disclosures that follow reflect estimates of proved reserves for our consolidated subsidiaries and equity companies of natural gas, oil, and natural gas liquids owned at December 31, 2012, 2011 and 2010 and changes in proved reserves during 2012, 2011 and 2010. Our year-end reserve volumes in the following tables were calculated using average prices during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period. These reserve quantities are also used in calculating unit-of-production depreciation rates and in calculating the standardized measure of discounted net cash flow. Estimates of volumes of proved reserves of natural gas at year end are expressed in billions of cubic feet of natural gas (Bcf) at a pressure base of 14.73 pounds per square inch for natural gas and in millions of barrels (MMBbls) for oil and natural gas liquids.

For our wholly owned properties in the lower 48 states, the prices used in our reserve reports were $2.75 per mcf for the 12-month average of natural gas, $33.74 per barrel for natural gas liquids and $94.71 per barrel for oil at December 31, 2012. For our wholly owned properties in Alaska, the price used in our reserve report was $110.56 per barrel for oil at December 31, 2012. For our wholly owned properties in Canada, the price used in our reserve report was $1.05 per mcf for the 12-month average of natural gas at December 31, 2012.

For our wholly owned properties in the United States, the prices used in our reserve reports were $4.12 per mcf for the 12-month average of natural gas, $57.71 per barrel for natural gas liquids and $96.19 per barrel for oil at December 31, 2011. For our wholly owned properties in Canada, the price used in our reserve reports was $3.85 per mcf for the 12-month average of natural gas at December 31, 2011.

For our wholly owned properties in the United States, the prices used in our reserve reports were $3.72 per mcf for the 12-month average of natural gas, $36.43 per barrel for liquid natural gas and $61.12 per barrel for oil at December 31, 2010. For our wholly owned properties in Canada, the price used in our reserve reports was $2.81 per mcf for the 12-month average of natural gas at December 31, 2010. The 12-month average price for natural gas used in the reserve report by our unconsolidated Canada joint venture was $2.78 per mcf at December 31, 2010. For our wholly owned properties in Colombia, the price used in our reserve reports was $78.21 per barrel for oil at December 31, 2010. The oil price used in the reserve report by our unconsolidated Colombia joint venture was $76.00 per barrel at December 31, 2010.

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain.

Revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields due to the evaluation or re-evaluation of (1) already available geologic, reservoir or production data, (2) new geologic, reservoir or production data or (3) changes in average prices and year-end costs that are used in the estimation of reserves. This category can also include significant changes in either development strategy or production equipment/facility capacity.

Proved reserves include 100 percent of each majority-owned affiliate s participation in proved reserves and our ownership percentage of the proved reserves of equity companies, but exclude royalties and quantities due others.

In the proved reserves tables, consolidated reserves and equity company reserves are reported separately. However, we do not view equity company reserves any differently than those of our consolidated subsidiaries.

Net proved developed reserves are those volumes that are expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well. Net proved undeveloped reserves are those volumes that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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	United States		Canada		Colombia		Total	
Reserves	**Liquids (MMBbls)**	**Natural Gas (Bcf)**	**Liquids (MMBbls)**	**Natural Gas (Bcf)**	**Liquids (MMBbls)**	**Natural Gas (Bcf)**	**Liquids (MMBbls)**	**Natural Gas (Bcf)**
Net proved reserves of consolidated subsidiaries								
January 1, 2010	0.4	29.6		5.0	0.9		1.3	34.6
Revisions	0.1	(11.7)		3.6	(0.7)		(0.6)	(8.1)
Extensions, additions and discoveries		5.0			2.0		2.0	5.0
Production	(0.1)	(3.1)		(3.1)	(0.2)		(0.3)	(6.2)
Purchases in place	20.8(2)						20.8	
Sales in place								
December 31, 2010	21.2	19.8		5.5	2.0		23.2	25.3
Revisions	0.1	(3.9)		0.9			0.1	(3.0)
Extensions, additions and discoveries	1.6	4.0					1.6	4.0
Production	(0.2)	(3.0)		(2.1)	(0.1)		(0.3)	(5.1)
Purchases in place				3.9				3.9
Sales in place	(20.9)(2)				(1.9)		(22.8)	
December 31, 2011	1.8	16.9		8.2			1.8	25.1
Revisions	(0.2)	0.6		1.5			(0.2)	2.1
Extensions, additions and discoveries	14.8(3)	0.9					14.8	0.9
Production	(0.2)	(0.8)		(2.0)			(0.2)	(2.8)
Purchases in place								
Sales in place	(0.8)	(16.5)(4)					(0.8)	(16.5)
December 31, 2012	15.4	1.1		7.7			15.4	8.8

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Reserves	United States Liquids (MMBbls)	United States Natural Gas (Bcf)	Canada Liquids (MMBbls)	Canada Natural Gas (Bcf)	Colombia Liquids (MMBbls)	Colombia Natural Gas (Bcf)	Total Liquids (MMBbls)	Total Natural Gas (Bcf)
Proportional interest in proved reserves of equity companies								
January 1, 2010	5.2	466.9		7.5	0.6		5.8	474.4
Revisions	1.5	(119.1)		(0.8)	0.5		2.0	(119.9)
Extensions, additions and discoveries	0.6	108.5			1.3		1.9	108.5
Production	(0.2)	(12.3)		(1.5)	(0.3)		(0.5)	(13.8)
Purchases in place	0.8	109.8					0.8	109.8
Sales in place		(1.0)			(0.2)		(0.2)	(1.0)
December 31, 2010	7.9	552.8		5.2	1.9		9.8	558.0
Revisions	(4.2)	(359.0)					(4.2)	(359.0)
Extensions, additions and discoveries	3.2	103.1					3.2	103.1
Production	(0.4)	(18.6)		(0.4)	(0.3)		(0.7)	(19.0)
Purchases in place	9.4	304.2(5)					9.4	304.2
Sales in place				(4.8)(6)	(1.6)(7)		(1.6)	(4.8)
December 31, 2011	15.9	582.5					15.9	582.5
Revisions	(1.5)	(22.6)					(1.5)	(22.6)
Extensions, additions and discoveries	1.4	8.9					1.4	8.9
Production	(0.5)	(19.0)					(0.5)	(19.0)
Purchases in place								
Sales in place (8)	(15.3)	(549.8)					(15.3)	(549.8)
December 31, 2012								

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	United States		Canada		Colombia		Total	
Reserves	**Liquids (MMBbls)**	**Natural Gas (Bcf)**	**Liquids (MMBbls)**	**Natural Gas (Bcf)**	**Liquids (MMBbls)**	**Natural Gas (Bcf)**	**Liquids (MMBbls)**	**Natural Gas (Bcf)**
Total proved reserves at December 31, 2010	29.1	572.6		10.7	3.9		33.0	583.3
Total proved reserves at December 31, 2011	17.7	599.4		8.2			17.7	607.6
Total proved reserves at December 31, 2012	15.4	1.1		7.7			15.4	8.8
Proved Developed Reserves at December 31, 2010								
Consolidated subsidiaries	2.7	17.1		5.5	1.6		4.3	22.6
Equity companies (1)	3.0	147.1		5.2	0.5		3.5	152.3
Proved Developed Reserves at December 31, 2011								
Consolidated subsidiaries	0.9	13.6		8.2			0.9	21.8
Equity companies (1)	6.3	256.4					6.3	256.4
Proved Developed Reserves at December 31, 2012								
Consolidated subsidiaries	1.1	0.4		7.7			1.1	8.1
Equity companies (1)								
Proved Undeveloped Reserves at December 31, 2010								
Consolidated subsidiaries	18.5	2.7			0.4		18.9	2.7
Equity companies (1)	4.9	405.7			1.4		6.3	405.7
Proved Undeveloped Reserves at December 31, 2011								
Consolidated subsidiaries	0.9	3.3					0.9	3.3
Equity companies (1)	9.6	326.1					9.6	326.1
Proved Undeveloped Reserves at December 31, 2012								
Consolidated subsidiaries	14.3	0.7					14.3	0.7
Equity companies (1)								

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(1) Represents our proportionate share of interests in equity companies for the applicable year.

(2) On December 14, 2011, we sold our 25% working interest in the Cat Canyon and West Cat Canyon fields in Santa Barbara County, California purchased in 2010. We received approximately $71.6 million in cash from the sale.

(3) Relates primarily to the discovery of proved undeveloped reserves in our North Slope, Alaska field.

(4) Relates to the divestitures during 2012 of substantially all of our U.S. wholly owned gas properties.

(5) Relates to acquisitions of properties with 360.4 Bcfe and drilling of non-proved properties of 122.2 Bcfe. In addition, negative revisions of 384 Bcfe were noted primarily resulting from proved undeveloped reserves being reclassified to non-proved status in accordance with the SEC five-year guidance for recording proved reserves.

(6) Relates to proved reserves of 4.8 Bcfe that were exchanged for our ownership interest when SMVP dissolved in June 2011.

(7) Relates to the sale of Remora s assets which resulted in a decrease in proved reserves of 9.5 Bcfe.

(8) Relates to our sale of NFR Energy in December 2012, which included 15.1 MMBbls and 531.9 Bcf, respectively, of oil and natural gas.

Standardized Measure of Discounted Future Cash Flows

For the years ended December 31, 2012, 2011 and 2010, the standardized measure of discounted future net cash flow was computed by applying first-day-of-the-month average prices, year-end costs and legislated tax rates and a discount factor of 10 percent to proved reserves. Estimated future net cash flows for all periods presented are reduced by estimated future development, production, abandonment and dismantlement costs based on existing costs, assuming continuation of existing economic conditions, and by estimated future income tax expense. These estimates also include assumptions about the timing of future production of proved reserves, and timing of future development, production costs, and abandonment and dismantlement. Income tax expense, both U.S. and global, is calculated by applying the existing statutory tax rates, including any known future changes, to the pretax net cash flows giving effect to any permanent differences and reduced by the applicable tax basis. The 10-percent discount factor is prescribed by GAAP.

The present value of future net cash flows does not purport to be an estimate of the fair market value of our consolidated subsidiaries and equity companies proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money and the risks inherent in producing oil and gas. Significant changes in estimated reserve volumes or commodity prices could have a material effect on our consolidated financial statements.

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	United States	Canada	Colombia	Total
		(In thousands)		
Standardized Measure of Discounted Future Cash Flows				
For the year ended December 31, 2010:				
Consolidated Subsidiaries				
Future cash flows from sales of oil and gas	$ 1,468,944	$ 16,435	$ 156,921	$ 1,642,300
Future production costs	(481,487)	(5,600)	(83,556)	(570,643)
Future development costs	(152,309)	(360)	(16,216)	(168,885)
Future income tax expense (2)	(268,774)			(268,774)
Future net cash inflows	566,374	10,475	57,149	633,998
Effect of discounting net cash flows at 10%	(353,232)	(2,046)	(10,256)	(365,534)
Discounted future net cash flows	$ 213,142	$ 8,429	$ 46,893	$ 268,464
Equity Companies (1)				
Future cash flows from sales of oil and gas	$ 2,889,308	$ 14,713	$ 141,410	$ 3,045,431
Future production costs	(752,792)	(6,463)	(56,837)	(816,092)
Future development costs	(850,053)	(992)	(12,307)	(863,352)
Future income tax expense (3)				
Future net cash inflows	1,286,463	7,258	72,266	1,365,987
Effect of discounting net cash flows at 10%	(995,091)	(1,477)	(14,313)	(1,010,881)
Discounted future net cash flows	$ 291,372	$ 5,781	$ 57,953	$ 355,106
Total consolidated and equity interests in standardized measure of discounted future net cash flows	$ 504,514	$ 14,210	$ 104,846	$ 623,570

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	United States	Canada	Colombia	Total
		(In thousands)		
Standardized Measure of Discounted Future Cash Flows				
For the year ended December 31, 2011:				
Consolidated Subsidiaries				
Future cash flows from sales of oil and gas	$ 225,141	$ 20,906	$	$ 246,047
Future production costs	(66,448)	(5,761)		(72,209)
Future development costs	(45,505)	(1,607)		(47,112)
Future income tax expense (2)				
Future net cash inflows	113,188	13,538		126,726
Effect of discounting net cash flows at 10%	(55,886)	(2,527)		(58,413)
Discounted future net cash flows	$ 57,302	$ 11,011	$	$ 68,313
Equity Companies (1)				
Future cash flows from sales of oil and gas	$ 3,347,348	$	$	$ 3,347,348
Future production costs	(1,005,922)			(1,005,922)
Future development costs	(660,509)			(660,509)
Future income tax expense (3)				
Future net cash inflows	1,680,917			1,680,917
Effect of discounting net cash flows at 10%	(1,098,854)			(1,098,854)
Discounted future net cash flows	$ 582,063	$	$	$ 582,063
Total consolidated and equity interests in standardized measure of discounted future net cash flows	$ 639,365	$ 11,011	$	$ 650,376
For the year ended December 31, 2012:				
Consolidated Subsidiaries				
Future cash flows from sales of oil and gas	$ 1,633,946	$ 8,101	$	$ 1,642,047
Future production costs	(427,971)	(5,060)		(433,031)
Future development costs	(402,392)	(376)		(402,768)
Future income tax expense (2)	(305,215)			(305,215)
Future net cash inflows	498,368	2,665		501,033
Effect of discounting net cash flows at 10%	(218,139)	(268)		(218,407)
Discounted future net cash flows	$ 280,229	$ 2,397	$	$ 282,626
Equity Companies (1)				
Future cash flows from sales of oil and gas	$	$	$	$
Future production costs				
Future development costs				
Future income tax expense (3)				
Future net cash inflows				
Effect of discounting net cash flows at 10%				
Discounted future net cash flows	$	$	$	$
Total consolidated and equity interests in standardized measure of discounted future net cash flows	$ 280,229	$ 2,397	$	$ 282,626

(1) Represents our proportionate share of interests in equity companies for the applicable year.

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(2) For Canada and Colombia, there are net operating loss carryforwards that are expected to offset any future taxable earnings.

(3) Equity companies are pass-through entities for tax purposes.

Change in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following table reflects the estimate of changes in the standardized measure of discounted future net cash flows from proved reserves:

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	United States		Canada		Colombia		Total
			(In thousands)				
Change in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves							
Consolidated Subsidiaries							
Discounted future net cash flows as of December 31, 2010	$	213,142	$	8,429	$	46,893	$ 268,464
Value of reserves added during the year due to extensions, discoveries and net purchases less related costs		32,838					32,838
Changes in value of previous-year reserves due to:							
Sales of oil and gas produced, net of production costs		(14,247)		(5,848)		(8,674)	(28,769)
Development costs incurred during the year		360					360
Net change in prices and production costs		(15,274)		1,221			(14,053)
Net change in future development costs		775					775
Revisions of previous reserve estimates		(5,285)		1,219		19,859	15,793
Purchases of reserves				4,557			4,557
Divestiture of reserves		(272,448)(4)				(58,078)(5)	(330,526)
Accretion of discount		30,021		843			30,864
Other		356		590			946
Net change in income taxes (2)		87,064					87,064
Total change in the standardized measure for consolidated subsidiaries	$	(155,840)	$	2,582	$	(46,893)	$ (200,151)
Discounted future net cash flows as of December 31, 2011	$	57,302	$	11,011	$		$ 68,313
Value of reserves added during the year due to extensions, discoveries and net purchases less related costs		454,913					454,913
Changes in value of previous-year reserves due to:							
Sales of oil and gas produced, net of production costs		(14,958)		1,101			(13,857)
Development costs incurred during the year		11,343		623			11,966
Net change in prices and production costs		13,174		(11,659)			1,515
Net change in future development costs		1,164		4			1,168
Revisions of previous reserve estimates		(894)		427			(467)
Purchases of reserves							
Divestiture of reserves		(33,082)					(33,082)
Accretion of discount		5,730		1,101			6,831
Other		(25,922)		(211)			(26,133)
Net change in income taxes (2)		(188,541)					(188,541)
Total change in the standardized measure for consolidated subsidiaries	$	222,927	$	(8,614)	$		$ 214,313
Discounted future net cash flows as of December 31, 2012	$	280,229	$	2,397	$		$ 282,626

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	United States	Canada	Colombia	Total
		(In thousands)		
Change in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves				
Equity Companies (1)				
Discounted future net cash flows as of December 31, 2010	$ 291,372	$ 5,781	$ 57,953	$ 355,106
Value of reserves added during the year due to extensions, discoveries and net purchases less related costs	83,692			83,692
Changes in value of previous-year reserves due to:				
Sales of oil and gas produced, net of production costs	(71,143)	3,245	(16,132)	(84,030)
Development costs incurred during the year	44,294			44,294
Net change in prices and production costs	(20,856)			(20,856)
Net change in future development costs	(51,098)			(51,098)
Revisions of previous reserve estimates	20,178			20,178
Purchases of reserves	262,719			262,719
Divestiture of reserves		(9,026)(6)	(41,821)(5)	(50,847)
Sales of reserves				
Accretion of discount	29,155			29,155
Other	(6,250)			(6,250)
Net change in income taxes (3)				
Total change in the standardized measure for equity companies	$ 290,691	$ (5,781)	$ (57,953)	$ 226,957
Discounted future net cash flows as of December 31, 2011	$ 582,063	$	$	$ 582,063
Value of reserves added during the year due to extensions, discoveries and net purchases less related costs	16,926			16,926
Changes in value of previous-year reserves due to:				
Sales of oil and gas produced, net of production costs	(48,432)			(48,432)
Development costs incurred during the year	24,356			24,356
Net change in prices and production costs				
Net change in future development costs				
Revisions of previous reserve estimates	(377,184)			(377,184)
Purchases of reserves				
Divestiture of reserves (6)	(246,093)			(246,093)
Accretion of discount	58,206			58,206
Other	(9,842)			(9,842)
Net change in income taxes (3)				
Total change in the standardized measure for equity companies	$ (582,063)	$	$	$ (582,063)
Discounted future net cash flows as of December 31, 2012	$	$	$	$

(1) Represents our proportionate share of interests in equity companies for the applicable year.

(2) For Canada and Colombia, there are net operating loss carryforwards that are expected to offset any future taxable earnings.

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(3) Equity companies are pass-through entities for tax purposes. On December 14, 2011, we sold our 25% working interest in the Cat Canyon and West Cat Canyon fields in Santa Barbara County, California. We received approximately $71.6 million in cash from the sale. During 2010, we purchased our 25% working interest and at December 31, 2010, proved reserves in Cat Canyon were estimated at 20.8 MMBbls.

(4) In April 2011, some of our wholly owned oil and gas assets in Colombia were sold. Remora completed sales of its oil and gas assets in Colombia, resulting in a decrease of proved reserves of 9.5 Bcfe, in the second quarter of 2011.

(5) In June 2011, SMVP was dissolved, resulting in a decrease in proved reserves of 4.8 Bcfe that was exchanged for our ownership interest.

(6) Includes $233 million, representing our divestiture of NFR Energy in December 2012.

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

Not applicable.

ITEM 9A. ***CONTROLS AND PROCEDURES***

(a) Disclosure Controls and Procedures. We maintain a set of disclosure controls and procedures designed to provide reasonable assurance that information required to be disclosed in our reports filed under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. We have investments in certain unconsolidated entities that we do not control or manage. Because we do not control or manage these entities, our disclosure controls and procedures with respect to these entities are necessarily more limited than those we maintain with respect to our consolidated subsidiaries.

The Company s management, with the participation of the Company s Chairman, President and Chief Executive Officer and its Principal Accounting and Financial Officer, has evaluated tvnhe effectiveness of the Company s disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Based on this evaluation, the Company s Chairman, President and Chief Executive Officer and its Principal Accounting and Financial Officer have concluded that, as of the end of the period, the Company s disclosure controls and procedures are effective, at the reasonable assurance level, in recording, processing, summarizing and reporting, on a timely basis, information required to be disclosed by the Company in reports that it files or submits under the Exchange Act and are effective, at the reasonable assurance level, in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the Company s management, including the Company s Chairman, President and Chief Executive Officer and its Principal Accounting and Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

(b) Changes in Internal Control Over Financial Reporting. There have not been any changes in the Company s internal control over financial reporting (identified in connection with the evaluation required by paragraph (d) in Rules 13a-15 and 15d-15 under the Exchange Act) during the most recently completed fiscal quarter that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

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Management s Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (iii) 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.

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 these 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, though not eliminate, this risk.

Management conducted an evaluation of the effectiveness of the Company s internal control over financial reporting based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation, management concluded that the Company s internal control over financial reporting was effective as of December 31, 2012. PricewaterhouseCoopers LLP has issued a report on the effectiveness of internal control over financial reporting, which is included in Part II, Item 8 of this report.

ITEM 9B. *OTHER INFORMATION*

Not applicable.

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PART III

ITEM 10. *DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE*

The information called for by this item will be contained in the definitive Proxy Statement to be distributed in connection with our 2013 annual general meeting of shareholders under the captions *Election of Directors* , *Other Executive Officers* , *Section 16(a) Beneficial Ownership Reporting Compliance* , and is incorporated into this document by reference.

We have adopted a Code of Business Conduct that applies to all directors, employees, including our principal executive officer and principal financial and accounting officer. The Code of Ethics satisfies the SEC s definition of a Code of Ethics and is posted on our website at *www.nabors.com*. We intend to disclose on our website any amendments to the Code and any waivers of the Code that apply to our principal executive officer, principal financial officer, or principal accounting officer.

On June 15, 2012, we filed with the New York Stock Exchange the Annual CEO Certification regarding our compliance with the Exchange s Corporate Governance listing standards as required by Section 303A-12(a) of the Exchange s Listed Company Manual.

ITEM 11. *EXECUTIVE COMPENSATION*

The information called for by this item will be contained in our definitive Proxy Statement to be distributed in connection with our 2013 annual general meeting of shareholders under the caption *Management Compensation* and except as specified in the following sentence, is incorporated into this document by reference. Information in Nabors 2013 Proxy Statement not deemed to be soliciting material or filed with the Commission under its rules, including the Compensation Committee Report, is not deemed to be incorporated by reference.

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ITEM 12. ***SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED SHAREHOLDER MATTERS***

We maintain five different equity compensation plans: 1996 Employee Stock Plan, 1998 Employee Stock Plan, 1999 Stock Option Plan for Non-Employee Directors and 2003 Employee Stock Plan pursuant to which we may grant equity awards to eligible persons. The terms of our equity compensation plans are described more fully below.

The following table gives information about these equity compensation plans as of December 31, 2012:

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights		(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	19,043,180	$	19.8289	14,329,808
Equity compensation plans not approved by security holders	3,420,363	$	24.4957	828,952
Total	22,463,543			15,158,760

(1) The 1996 Employee Stock Plan incorporated an evergreen formula pursuant to which on each January 1, the aggregate number of shares reserved for issuance under the plan were increased by an amount equal to 1.5% of the common shares outstanding on September 30 of the immediately preceding fiscal year. Effective January 1, 2006, no new awards could be granted under this plan, but there are outstanding awards that were granted before this date.

(2) The 2003 Employee Stock Plan provided, commencing on June 1, 2006 and expiring January 1, 2011, on each January 1 for an automatic increase in the number of shares reserved and available for issuance under the Plan by an amount equal to two percent (2%) of the Company s outstanding common shares as of each June 1 or January 1. The Plan expires June 3, 2013 and no awards can be granted from the plan after this date.

Following is a brief summary of the material terms of the plans that have not been approved by our shareholders. Unless otherwise indicated, (1) each plan is administered by an independent committee appointed by the Company s Board of Directors; (2) the exercise price of options granted under each plan must be no less than 100% of the fair market value per common share on the date of the grant of the option; (3) the term of an award granted under each plan may not exceed 10 years; (4) options granted under the plan are nonstatutory options (NSOs) not intended to qualify under Section 422 of the Internal Revenue Code of 1986, as amended (the IRC); and (5) unless otherwise determined by the committee in its discretion, options may not be exercised after the optionee has ceased to be employed by the Company.

1998 Employee Stock Plan

The plan reserved for issuance up to 35,000,000 common shares of the Company pursuant to the exercise of options granted under the plan. The persons eligible to participate in the plan were employees and consultants of the Company. Options granted to employees were either awards of shares, non-qualified stock options (each, an NQSO), incentive stock options (each, an ISO) or stock appreciation rights (each, an SAR). An optionee may reduce the option exercise price by paying the Company in cash, shares, options, or the equivalent, an amount equal to the difference between the exercise price and the reduced exercise price of the option. The administrative committee established performance goals for stock awards in writing and not later than the date required for compliance under Section 162(m) of the IRC, and vesting of these shares was contingent upon the attainment of

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such performance goals. Stock awards vest over a period determined by the committee. The Plan expired on January 8, 2008 and effective that date, no new awards could be granted even though there are outstanding awards that were granted before this date. The committee could grant ISOs of not less than 100% of the fair market value per common share on the date of grant; except that in the event the optionee owns on the date of grant, securities possessing more than 10% of the total combined voting power of all classes of securities of the Company or of any subsidiary of the Company, the price per share must not have been less than 110% of the fair market value per common share on the date of the grant. The option must expire five years from the date it is granted. SARs may be granted in conjunction with all or part of any option granted under the plan, in which case the exercise of the SAR must require the cancellation of a corresponding portion of the option; conversely, the exercise of the option will result in cancellation of a corresponding portion of the SAR. In the case of a NQSO, SARs may be granted either at or after the time of grant of the option. In the case of an ISO, SARs may be granted only at the time of grant of the option. A SAR may also be granted on a stand-alone basis. The term of a SAR must be established by the committee. The exercise price of a SAR cannot be less than 100% of the fair market value per common share on the date of grant. The committee has the authority to make provisions in its award and grant agreements to address vesting and other issues arising in connection with a change of control.

1999 Stock Option Plan for Non-Employee Directors

The plan reserves for issuance up to 3,000,000 common shares of the Company pursuant to the exercise of options granted under the plan. The plan is administered by the Board of Directors or a committee appointed by the Board. Eligible directors may not consider or vote on the administration of the plan or serve as a member of the committee. Options may be granted under the plan to non-employee directors of the Company. Options vest and become non-forfeitable on the first anniversary of the option grant if the optionee has continued to serve as a director until that day, unless otherwise provided. In the event of termination of an optionee s service as a director by reason of voluntary retirement, declining to stand for re-election or becoming a full-time employee of the Company or a subsidiary of the Company, all unvested options granted under the Plan automatically expire and are not exercisable, and all unexercised options continue to be exercisable until their stated expiration date. In the event of death or disability of an optionee while the optionee is a director, the then-outstanding options of such optionee become exercisable for two years from the date of the death or disability. All unvested options automatically vest and become non-forfeitable as of the date of death or disability and become exercisable for two years from the date of the death of the optionee or until the stated expiration date, whichever is earlier. In the event of the termination of an optionee s service as a director by the Board of Directors for cause or the failure of such director to be re-elected, the administrator of the plan in its sole discretion can cancel the then-outstanding options of the optionee, including options that have vested, and those options automatically expire and become non-exercisable on the effective date of the termination.

The remainder of the information called for by this item will be contained in our definitive Proxy Statement to be distributed in connection with our 2013 annual general meeting of shareholders under the caption *Share Ownership of Management and Principal Shareholders* and is incorporated into this document by reference.

ITEM 13. ***CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE***

The information called for by this item will be contained in our definitive Proxy Statement to be distributed in connection with our 2013 annual general meeting of shareholders under the caption *Certain Relationships and Related Transactions* and is incorporated into this document by reference.

ITEM 14. ***INDEPENDENT PUBLIC ACCOUNTANTS***

The information called for by this item will be contained in our definitive Proxy Statement to be distributed in connection with our 2013 annual general meeting of shareholders under the caption *Independent Auditor Fees* and is incorporated into this document by reference.

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PART IV

ITEM 15. ***EXHIBITS, FINANCIAL STATEMENT SCHEDULE***

(a) The following documents are filed as part of this report:

(1) Financial Statements

	Page No.
Consolidated Balance Sheets as of December 31, 2012 and 2011	115
Consolidated Statements of Income (Loss) for the Years Ended December 31, 2012, 2011 and 2010	117
Consolidated Statements of Other Comprehensive Income (Loss) for the Years Ended December 31, 2012, 2011 and 2010	120
Consolidated Statements of Cash Flows for the Years Ended December 31, 2012, 2011 and 2010	123
Consolidated Statements of Changes in Equity for the Years Ended December 31, 2012, 2011 and 2010	

(2) Financial Statement Schedule

	Page No.
Schedule II Valuation and Qualifying Accounts	150

All other supplemental schedules are omitted because of the absence of the conditions under which they would be required or because the required information is included in the financial statements or related notes.

(b) Exhibit Index

See the Exhibit Index for a list of those exhibits filed herewith, which Exhibit Index also includes and identifies management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601 of Regulation S-K.

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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.

NABORS INDUSTRIES LTD.

By:	/s/ Anthony G. Petrello Anthony G. Petrello Chairman, President and Chief Executive Officer (Principal Executive Officer)
By:	/s/ R. Clark Wood R. Clark Wood Principal Accounting and Financial Officer
Date:	March 1, 2013

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

Signature	Title	Date
/s/ Anthony G. Petrello Anthony G. Petrello	Chairman, President and Chief Executive Officer	March 1, 2013
/s/ R. Clark Wood R. Clark Wood	Principal Accounting and Financial Officer	March 1, 2013
/s/ James R. Crane James R. Crane	Director	March 1, 2013
/s/ Michael C. Linn Michael C. Linn	Director	March 1, 2013
/s/ John V. Lombardi John V. Lombardi	Director	March 1, 2013
/s/ James L. Payne James L. Payne	Director	March 1, 2013
/s/ Myron M. Sheinfeld Myron M. Sheinfeld	Director	March 1, 2013

/s/ John Yearwood John Yearwood	Director	March 1, 2013

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SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 2012, 2011 and 2010

	Balance at Beginnning of Period	Charged to Costs and Expenses	Charged to Other Accounts (In thousands)	Deductions	Balance at End of Period
2012					
Allowance for doubtful accounts	$ 41,703	(5,979)	179	(3,056)	$ 32,847
Inventory reserve	$ 6,984	(3,141)	9	2,793	$ 6,645
Valuation allowance on deferred tax assets	$ 1,485,540		35,312		$ 1,520,852
2011					
Allowance for doubtful accounts	$ 22,507	5,352	(29)	13,873	$ 41,703
Inventory reserve	$ 6,784	(1,185)	1,889	(504)	$ 6,984
Valuation allowance on deferred tax assets	$ 1,514,153			(28,613)	$ 1,485,540
2010					
Allowance for doubtful accounts	$ 23,681	1,545	167	(2,886)	$ 22,507
Inventory reserve	$ 4,824	(182)	1,695	447	$ 6,784
Valuation allowance on deferred tax assets	$ 1,570,890			(56,737)	$ 1,514,153

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Exhibit Index

Exhibit No.	Description
2.1	Agreement and Plan of Merger among Nabors Industries, Inc., Nabors Acquisition Corp. VIII, Nabors Industries Ltd. and Nabors US Holdings Inc. (incorporated by reference to Annex I to the proxy statement/prospectus included in our Registration Statement on Form S-4 (File No. 333-76198) filed with the SEC on May 10, 2002, as amended).
2.2	Agreement and Plan of Merger, by and among Nabors Industries Ltd., Diamond Acquisition Corp., and Superior, dated as of August 6, 2010 (incorporated by reference to Exhibit 2.2 to our Form 8-K (File No. 001-32657) filed with the SEC on August 9, 2010).
3.1	Memorandum of Association of Nabors Industries Ltd. (incorporated by reference to Annex II to the proxy statement/prospectus included in our Registration Statement on Form S-4 (File No. 333-76198) filed with the SEC on May 10, 2002, as amended).
3.2	Amended and Restated Bye-Laws of Nabors Industries Ltd. (incorporated by reference to Exhibit 3.2 to our Form 10-Q (File No. 001-32657) filed with the SEC on August 3, 2012).
4.1	Purchase Agreement, dated February 14, 2008, among Nabors Industries, Inc., Nabors Industries Ltd., Citigroup Global Markets Inc. and UBS Securities LLC, with respect to Nabors Industries, Inc. s 6.15% Senior Notes due 2018 (incorporated by reference to Exhibit 4.1 to our Form 8-K (File No. 001-32657) filed with the SEC on February 25, 2008).
4.1(a)	Indenture, dated February 20, 2008, among Nabors Industries, Inc., Nabors Industries Ltd. and Wells Fargo Bank, National Association, as trustee, with respect to Nabors Industries, Inc. s 6.15% Senior Notes due 2018 (including form of 6.15% Senior Note due 2018) (incorporated by reference to Exhibit 4.2 to our Form 8-K (File No. 001-32657) filed with the SEC on February 25, 2008).
4.1(b)	Registration Rights Agreement, dated as of February 20, 2008, among Nabors Industries, Inc., Nabors Industries Ltd., Citigroup Global Markets Inc. and UBS Securities LLC, with respect to Nabors Industries, Inc. s 6.15% Senior Notes due 2018 (incorporated by reference to Exhibit 4.3 to our Form 8-K (File No. 001-32657) filed with the SEC on February 25, 2008).
4.2	Purchase Agreement, dated July 17, 2008, among Nabors Industries, Inc., Nabors Industries Ltd., Citigroup Global Markets Inc. and UBS Securities LLC, with respect to Nabors Industries, Inc. s 6.15% Senior Notes due 2018 (incorporated by reference to Exhibit 4.1 to our Form 8-K (File No. 001-32657) filed with the SEC on July 23, 2008).
4.2(a)	Registration Rights Agreement, dated July 22, 2008, among Nabors Industries, Inc., Nabors Industries Ltd., Citigroup Global Markets Inc. and UBS Securities LLC, with respect to Nabors Industries, Inc. s 6.15% Senior Notes due 2018 (incorporated by reference to Exhibit 4.2 to our Form 8-K (File No. 001-32657) filed with the SEC on July 23, 2008).
4.3	Purchase Agreement, dated January 7, 2009, among Nabors Industries, Inc., Nabors Industries Ltd., Goldman, Sachs & Co., UBS Securities LLC, Citigroup Global Markets Inc., Deutsche Bank Securities Inc., Howard Weil Incorporated, J.P. Morgan Securities Inc., Morgan Stanley & Co. Incorporated, Tudor, Pickering, Holt & Co. Securities, Inc. and Wells Fargo Securities, LLC, with respect to Nabors Industries, Inc. s 9.25% Senior Notes due 2019 (incorporated by reference to Exhibit 4.1 to our Form 8-K (File No. 001-32657) filed with the SEC on January 14, 2009).
4.3(a)	Indenture related to the Senior Notes due 2019, dated as of January 12, 2009, among Nabors Industries, Inc., Nabors Industries Ltd. and Wells Fargo Bank, National Association, as trustee, with respect to Nabors Industries, Inc. s 9.25% Senior Notes due 2019 (including form of 9.25% Senior Note due 2019) (incorporated by reference to Exhibit 4.2 to our Form 8-K (File No. 001-32657) filed with the SEC on January 14, 2009).
4.3(b)	Registration Rights Agreement, dated as of January 12, 2009, among Nabors Industries, Inc., Nabors Industries Ltd., Goldman, Sachs & Co., UBS Securities LLC, Citigroup Global Markets Inc., Deutsche Bank Securities Inc., Howard Weil

	Incorporated, J.P. Morgan Securities Inc., Morgan Stanley & Co. Incorporated, Tudor, Pickering, Holt & Co. Securities, Inc. and Wells Fargo Securities, LLC, with respect to Nabors Industries, Inc. s 9.25% Senior Notes due 2019 (incorporated by reference to Exhibit 4.2 to our Form 8-K (File No. 001-32657) filed with the SEC on January 14, 2009).
4.4	Purchase Agreement, dated September 9, 2010, among Nabors Industries, Inc., Nabors Industries

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	Ltd., UBS Securities LLC, Citigroup Global Markets Inc., Deutsche Bank Securities Inc., Mizuho Securities USA Inc., Banc of America Securities LLC, Morgan Stanley & Co. Incorporated, HSBC Securities (USA) Inc., PNC Capital Markets LLC and Scotia Capital (USA) Inc. with respect to Nabors Industries, Inc. s 5.0% Senior Notes due 2020 (incorporated by reference to Exhibit 4.1 to our Form 8-K (File No. 001-32657) filed with the SEC on September 15, 2010).
4.4(a)	Indenture, dated as of September 14, 2010, among Nabors Industries, Inc., Nabors Industries Ltd., Wilmington Trust Company, as trustee and Citibank, N.A. as securities administrator, with respect to Nabors Industries, Inc. s 5.0% Senior Notes due 2020 (including form of 5.0% Senior Note due 2020) (incorporated by reference to Exhibit 4.2 to our Form 8-K (File No. 001-32657) filed with the SEC on September 15, 2010).
4.4(b)	Registration Rights Agreement, dated as of September 14, 2010, among Nabors Industries, Inc., Nabors Industries Ltd., UBS Securities LLC, Citigroup Global Markets Inc., Deutsche Bank Securities Inc., Mizuho Securities USA Inc., Banc of America Securities LLC, Morgan Stanley & Co. Incorporated, HSBC Securities (USA) Inc., PNC Capital Markets LLC and Scotia Capital (USA) Inc. with respect to Nabors Industries, Inc. s 5.0% Senior Notes due 2020 (incorporated by reference to Exhibit 4.3 to our Form 8-K (File No. 001-32657) filed with the SEC on September 15, 2010).
4.5	Tender and Voting Agreement, by and among Nabors Industries Ltd., Diamond Acquisition Corp. and certain Superior stockholders, dated as of August 6, 2010 (incorporated by reference to Exhibit 10.2 to our Form 8-K (File No. 001-32657) filed with the SEC on August 9, 2010).
4.6	Purchase Agreement, dated August 16, 2011, among Nabors Industries, Inc., Nabors Industries Ltd., Citigroup Global Markets Inc., Mizuho Securities USA Inc., UBS Securities LLC, Morgan Stanley & Co. LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, HSBC Securities (USA) Inc. and PNC Capital Markets LLC with respect to Nabors Industries, Inc. s 4.625% Senior Notes due 2021 (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-32657) filed with the SEC on August 17, 2011).
4.6(a)	Indenture, dated as of August 23, 2011, among Nabors Industries, Inc., Nabors Industries Ltd., Wilmington Trust, National Association, as trustee and Citibank, N.A. as securities administrator, with respect to Nabors Industries, Inc. s 4.625% Senior Notes due 2021 (including form of 4.625% Senior Note due 2021) (incorporated by reference to Exhibit 4.1 to our Form 8-K (File No. 001-32657) filed with the SEC on August 24, 2011).
4.6(b)	Registration Rights Agreement, dated as of August 23, 2011, among Nabors Industries, Inc., Nabors Industries Ltd., and Citigroup Global Markets Inc. as representative of the Initial Purchasers, with respect to Nabors Industries, Inc. s 4.625% Senior Notes due 2021 (incorporated by reference to Exhibit 4.2 to our Form 8-K (File No. 001-32657) filed with the SEC on August 24, 2011).
4.7	Rights Agreement, dated July 16, 2012, between Nabors Industries Ltd. and Computershare Trust Company, N.A., as Rights Agent, including the Form of Certificate of Designations of Series A Junior Participating Preferred Shares, the Form of Right Certificate, and the Summary of Rights to Purchase Preferred Shares, respectively attached thereto as Exhibits A, B and C (incorporated by reference to Exhibit 4.1 to Nabors Industries Ltd. s Form 8-K (File No. 001-32657) filed with the Commission on July 17, 2012).
10.1(+)	Agreement, dated as of February 2, 2012, by and among Eugene M. Isenberg, Nabors Industries Ltd. and Nabors Industries, Inc. (incorporated by reference to Exhibit 99.1 to Nabors Industries Ltd. s Form 8-K (File No. 001-32657) filed with the Commission on February 6, 2012).
10.2 (+)	Executive Employment Agreement between Nabors Industries, Inc., Nabors Industries Ltd. and Anthony G. Petrello, dated as of April 1, 2009 (incorporated by reference to Exhibit 10.2 to our Form 8-K (File No. 001-32657) filed with the SEC on April 30, 2009).
10.2(a) (+)	First Amendment to Executive Employment Agreement between Nabors Industries, Inc., Nabors Industries Ltd. and Anthony G. Petrello, dated as of June 29, 2009 (incorporated by reference to Exhibit 10.2 to our Form 8-K (File No. 001-32657) filed with the SEC on July 1, 2009).
10.2(b) (+)	Second Amendment to Executive Employment Agreement between Nabors Industries, Inc., Nabors Industries Ltd. and Anthony G. Petrello, dated as of December 28, 2009 (incorporated by reference to Exhibit 10.2 to our Form 8-K (File

No. 001-32657) filed with the SEC on December 28, 2009).

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10.2(c) (+)	Employment Agreement effective October 1, 1996, among Nabors Industries, Inc. and Anthony G. Petrello (incorporated by reference to Exhibit 10.8 to our Form 10-Q (File No. 1-9245) filed May 16, 1997).
10.3	Form of Indemnification Agreement entered into between Nabors Industries Ltd. and the directors and executive officers (incorporated by reference to Exhibit 10.28 to our Form 10-K (File No. 000-49887) filed with the SEC on March 31, 2003).
10.4 (+)	Form of Stock Option Agreement Petrello/Isenberg (incorporated by reference to Exhibit 10.03 to our Form 8-K (File No. 000-49887) filed with the SEC on March 2, 2005).
10.5 (+)	Form of Stock Option Agreement Others (incorporated by reference to Exhibit 10.04 to our Form 8-K (File No. 000-49887) filed with the SEC on March 2, 2005).
10.6 (+)	2003 Employee Stock Plan (incorporated by reference to Annex D of our Proxy Statement (File No. 000-49887) filed with the SEC on May 8, 2003).
10.6(a) (+)	First Amendment to 2003 Employee Stock Plan (incorporated by reference to Exhibit 4.1 to our Form 10-Q (File No. 000-49887) filed with the SEC on August 3, 2005).
10.6(b) (+)	Amended and Restated 2003 Employee Stock Plan (incorporated by reference to Exhibit A of our Proxy Statement (File No. 001-32657) filed with the SEC on May 4, 2006).
10.6(c) (+)	Nabors Industries Ltd. Amended and Restated 2003 Employee Stock Plan (incorporated by reference to Exhibit A of our Revised Definitive Proxy Statement on Schedule 14A (File No. 001-32657) filed with the SEC on May 4, 2006) (incorporated by reference to Exhibit 99.1 to our Form S-8 filed with the SEC on November 12, 2008).
10.6(d)(+)	Form of Stock Option Agreement Others, pursuant to the 2003 Employee Stock Plan*(+).
10.6(e)(+)	Form of Restricted Stock Agreement Others, pursuant to the 2003 Employee Stock Plan*(+).
10.7(+)	1996 Employee Stock Plan (incorporated by reference to Nabors Industries Inc. s Registration Statement on Form S-8 (File No. 333-11313) filed with the SEC on September 3, 1996).
10.8 (+)	Nabors Industries, Inc. 1997 Executive Officers Incentive Stock Plan (incorporated by reference to Exhibit 10.20 to Nabors Industries, Inc. s Form 10-K (File No. 1-9245) filed with the SEC on December 29, 1997).
10.9 (+)	Nabors Industries, Inc. 1998 Employee Stock Plan (incorporated by reference to Exhibit 10.19 to Nabors Industries, Inc. s Form 10-K (File No. 1-9245) filed with the SEC on March 31, 1999).
10.10 (+)	Nabors Industries, Inc. 1999 Stock Option Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.21 to Nabors Industries, Inc. s Form 10-K (File No. 1-9245) filed with the SEC on March 31, 1999).
10.10(a) (+)	Amendment to Nabors Industries, Inc. 1999 Stock Option Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.19 to Nabors Industries, Inc. s Form 10-K (File No. 1-09245) filed with the SEC on March 19, 2002).
10.10(b) (+)	Amended and Restated 1999 Stock Option Plan for Non-Employee Directors (amended on May 2, 2003) (incorporated by reference to Exhibit 10.29 to our Form 10-Q (File No. 000-49887) filed with the SEC on May 12, 2003).
10.11	Credit Agreement, dated as of November 29, 2012, among Nabors Industries, Inc. as US borrower, Nabors Canada as Canadian borrower, Nabors Industries Ltd. as guarantor, HSBC Bank Canada as Canadian lender, the other lenders party thereto, Mizuho Corporate Bank, Ltd. and HSBC Bank USA, N.A. as documentation agents, HSBC Bank USA, N.A. as syndication agent and Citibank, N.A. as administrative agent for the US lenders (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-32657) filed with the SEC on November 30, 2012).
12	Computation of Ratios. *

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14	Code of Business Conduct (incorporated by reference to Exhibit 14 to our Form 10-K (File No. 000-49887) filed with the SEC on March 15, 2004).
18	Preference Letter of Independent Accountants Regarding Change in Accounting Principle (incorporated by reference to Exhibit 18 to our Form 10-Q (File No. 000-49887) filed with the SEC on November 2, 2005).
21	Significant Subsidiaries*
23.1	Consent of Independent Registered Public Accounting Firm PricewaterhouseCoopers LLP - Houston. *
23.2	Consent of DeGolyer and MacNaughton.*
23.3	Consent of AJM Deloitte*
23.4	Consent of Cawley, Gillespie & Associates, Inc.*
31.1	Rule 13a-14(a)/15d-14(a) Certification of Anthony G. Petrello, Chairman, President and Chief Executive Officer*
31.2	Rule 13a-14(a)/15d-14(a) Certification of R. Clark Wood, Principal Accounting and Financial Officer*
32.1	Certifications required by Rule 13a-14(b) or Rule 15d-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350), executed by Anthony G. Petrello, Deputy Chairman, President and Chief Executive Officer and R. Clark Wood, Principal Accounting and Financial Officer (furnished herewith).
99.1	Report of DeGolyer and MacNaughton.*
99.2	Report of AJM Deloitte*
99.3	Report of Cawley, Gillespie & Associates, Inc.*
101.INS	XBRL Instance Document*
101.SCH	XBRL Schema Document*
101.CAL	XBRL Calculation Linkbase Document*
101.LAB	XBRL Label Linkbase Document*
101.PRE	XBRL Presentation Linkbase Document*
101.DEF	XBRL Definition Linkbase Document*

* Filed herewith.

(+) Management contract or compensatory plan or arrangement.