ROWAN COMPANIES PLC
Form 10-K
February 26, 2016
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the year ended December 31, 2015

OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________

Commission File Number: 1-5491

Rowan Companies plc

(Exact name of registrant as specified in its charter)

England and Wales	98-1023315
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

2800 Post Oak Boulevard, Suite 5450
Houston, Texas 77056-6189
(Address of principal executive offices)

Registrant’s telephone number, including area code: (713) 621-7800

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

Title of each class	Name of each exchange on which registered
Class A ordinary shares, $0.125 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes ¨ No þ

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

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 (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. Large accelerated filer þ Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

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

The aggregate market value of common equity held by non-affiliates of the registrant was approximately $2.6 billion as of June 30, 2015, based upon the closing price of the registrant's ordinary shares on the New York Stock Exchange Composite Tape of $21.11 per share.

The number of Class A ordinary shares, $0.125 par value, outstanding at January 31, 2016, was 124,824,224, which excludes 1,123,200 shares held by an affiliated employee benefit trust.

DOCUMENTS INCORPORATED BY REFERENCE

Document	Part of Form 10-K
Portions of the Proxy Statement for the 2016 Annual General Meeting of Shareholders	Part III, Items 10-14

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FORWARD-LOOKING STATEMENTS

Statements contained in this report that are not historical facts are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements include words or phrases such as “anticipate,” “believe,” “estimate,” “expect,” “intend,” “plan,” “project,” “could,” “might,” “should,” “will,” “forecast,” “potential,” “outlook,” “scheduled,” “predict,” “will be,” “will continue,” “will likely res similar words and specifically include statements regarding expected financial and operating performance; dividend, share repurchases and debt retirement; business strategies; expected utilization, day rates, revenues, operating expenses, contract terms, contract backlog, and fleet status; capital expenditures; tax rates and positions; impairments; insurance coverages; access to financing and funding sources, including borrowings under our credit facility; repayment of debt; the availability, delivery, mobilization, contract commencement, relocation or other movement of rigs and the timing thereof; construction, enhancement, upgrade or repair and costs and timing thereof; the suitability of rigs for future contracts; general market, business and industry conditions, trends and outlook; rig demand; future operations; the impact of increasing regulatory requirements and complexity; expected contributions from our new rigs and our entry into the ultra-deepwater market; divestiture of selected assets; expense management; the likely outcome of legal proceedings or insurance or other claims and the timing thereof; activity levels in the offshore drilling market; customer drilling programs; the impact of competition and consolidation in the industry; timing of acquisitions, dispositions and other business transactions; and commodity prices. Such statements are subject to numerous risks, uncertainties and assumptions that may cause actual results to vary materially from those indicated, including:

- prices of oil and natural gas and industry expectations about future prices and impacts of global financial or economic downturns;
- changes in the offshore drilling market, including fluctuations in worldwide rig supply and demand, competition or technology;
- variable levels of drilling activity and expenditures, whether as a result of actions by OPEC, global capital markets and liquidity, prices of oil and natural gas or otherwise, which may cause us to idle or stack additional rigs;
- drilling permit and operations delays, moratoria or suspensions, new and future regulatory, legislative or permitting requirements (including requirements related to certification and testing of blowout preventers and other equipment or otherwise impacting operations), future lease sales, changes in laws, rules and regulations that have or may impose increased financial responsibility, additional oil spill contingency plan requirements and other governmental actions that may result in claims of force majeure or otherwise adversely affect our existing drilling contracts;
- governmental regulatory, legislative and permitting requirements affecting drilling operations or compliance obligations in the areas in which our rigs operate;
- tax matters, including our effective tax rates, tax positions, results of audits, changes in tax laws, treaties and regulations, tax assessments and liabilities for taxes;
- downtime, lost revenue and other risks associated with drilling operations, operating hazards, or rig relocations and transportation, including rig or equipment failure, collisions, damage and other unplanned repairs, the limited availability of transport vessels, hazards, self-imposed drilling limitations and other delays due to weather conditions or otherwise, and the limited availability or high cost of insurance coverage for certain offshore perils or associated removal of wreckage or debris and other losses;
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access to spare parts, equipment and personnel to maintain, upgrade and service our fleet;

- possible cancellation or suspension of drilling contracts as a result of economic conditions in the industry, force majeure, mechanical difficulties, delays, performance or other reasons;

- potential cost overruns and other risks inherent to construction, repair, inspections or enhancement of drilling units, unexpected delays in rig and equipment delivery and engineering or design issues following shipyard delivery, delays in acceptance by our customers, or delays in the dates our drilling units will enter a shipyard, be transported and delivered, enter service or return to service;

- changes or delays in actual contract commencement dates; contract terminations, contract option exercises, contract revenues, contract awards; the termination of contracts or renegotiation of contract terms by customers or payment or operational delays by our customers;

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- operating hazards, including environmental or other liabilities, risks, expenses or losses, whether related to well-control issues, or storm or hurricane damage, losses or liabilities (including wreckage or debris removal), collisions, or otherwise;
- our ability to retain highly skilled personnel on commercially reasonable terms, whether due to competition from other contract drillers, labor regulations or otherwise; our ability to seek and receive visas for our personnel to work in our areas of operation in a timely manner;
- governmental action and political and economic uncertainties, including uncertainty or instability resulting from civil unrest, political demonstrations, strikes, or outbreak or escalation of armed hostilities or other crises in oil or natural gas producing areas in which we operate, which may result in extended business interruptions, suspended operations, or claims by our customers of a force majeure situation and payment disputes;
- terrorism, piracy, cyber-breaches, outbreaks of any disease or epidemic and other related travel restrictions, political instability, hostilities, acts of war, nationalization, expropriation, confiscation or deprivation of our assets or military action impacting our operations, assets or financial performance in any of our areas of operations;
- the outcome of legal proceedings, or other claims or contract disputes, including any inability to collect receivables or resolve significant contractual or day rate disputes, any purported renegotiation, nullification, cancellation or breach of contracts with customers or other parties, and any failure to negotiate or complete definitive contracts following announcements of receipt of letters of intent;
- potential for asset impairments;
- impacts of any global financial or economic downturn;
- volatility in currency exchange rates and limitations on our ability to use or convert illiquid currencies through governmental licensing or other procedures;
- effects of accounting changes and adoption of accounting policies;
- costs and uncertainties associated with our 2012 redomestication from the United States to the United Kingdom, or changes in laws that could reduce or eliminate the anticipated benefits of the transaction;
- potential unplanned expenditures and funding requirements, including investments in pension plans and other benefit plans; and
- other important factors described from time to time in the reports filed by us with the Securities and Exchange Commission and the New York Stock Exchange.

All forward-looking statements contained in this Form 10-K speak only as of the date of this document and are expressly qualified in their entirety by such factors. We undertake no obligation to update or revise publicly any revisions to any such forward-looking statements that may be made to reflect events or circumstances after the date of this Form 10-K, or to reflect the occurrence of unanticipated events, except as required by applicable law.

Other relevant factors are included in Item 1A, “Risk Factors,” of this Form 10-K.

PART I

ITEM 1. BUSINESS

Overview

Rowan Companies plc is a public limited company incorporated under the laws of England and Wales and listed on the New York Stock Exchange. The terms “Rowan,” “Rowan plc,” “Company,” “we,” “us” and “our” refer to Rowan plc and i consolidated subsidiaries, unless the context otherwise requires.

Rowan plc is a global provider of offshore contract drilling services to the international oil and gas industry, with a focus on high-specification and premium jack-up rigs and ultra-deepwater drillships. Our fleet currently consists of 31 mobile offshore drilling

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units, including 27 self-elevating jack-up rigs and four ultra-deepwater drillships. Our fleet operates worldwide, including the United States Gulf of Mexico (US GOM), the United Kingdom (U.K.) and Norwegian sectors of the North Sea, the Middle East and Trinidad. In 2015, we completed our ultra-deepwater drillship construction program with the following four new drillships:

- the Rowan Renaissance, which commenced drilling operations offshore West Africa in April 2014 and is now operating in the US GOM;
- the Rowan Resolute, which commenced operations in the US GOM in October 2014;
- the Rowan Reliance, which commenced operations in the US GOM in February 2015; and
- the Rowan Relentless, which commenced operations in the US GOM in June 2015.

We contract our drilling rigs, related equipment and work crews primarily on a "day rate" basis. Under day rate contracts, we generally receive a fixed amount per day for each day we are performing drilling or related services. In addition, our customers may pay all or a portion of the cost of moving our equipment and personnel to and from the well site. Contracts generally range in duration from one month to multiple years.

For information with respect to our revenues, operating income and assets by operating segment, and revenues and assets by geographic area, see Note 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Drilling Fleet

We believe our high-specification and premium jack-up fleet and ultra-deepwater drillships are well positioned to serve the worldwide market for high-pressure/high-temperature (HPHT) wells, including those in demanding locations. Our drilling fleet consists of the following:

- Four ultra-deepwater drillships delivered in 2014 and 2015;
- Nineteen high-specification cantilever jack-up rigs, including three N-Class rigs, four EXL class rigs, three 240C class rigs, four enhanced Super Gorilla class rigs, one Gorilla class rig, and four Tarzan Class rigs. We use the term “high-specification” to describe jack-ups with a hook-load capacity of at least two million pounds.
- Eight premium cantilever jack-up rigs, including two Gorilla class rigs and six 116-C class rigs. We use the term “premium” to denote independent-leg cantilever jack-ups that can operate in at least 300 feet of water in benign environments.

Ultra-Deepwater Drillships. Our ultra-deepwater drillships are self-propelled vessels equipped with computer-controlled dynamic-positioning systems, which allow them to maintain position without anchors through the use of their onboard propulsion and station-keeping systems. Drillships have greater variable deck loading capacity than semisubmersible rigs, enabling them to carry more supplies on board and, thus, making them better suited for drilling in deep water in remote locations. Our drillships are equipped with two drilling stations within a single derrick allowing the drillships to perform preparatory activities off-line and potentially simultaneous drilling tasks during certain stages of drilling, subject to legal restrictions in various jurisdictions, enabling increased drilling efficiency particularly during the initial stages of a well. In addition, our drillships are equipped to drill in 12,000-foot water depths, are equipped with 2,500,000 pound hook-load capability, and are capable of drilling HPHT wells to 40,000-foot depths. Each is equipped with two fully redundant blowout preventers, which significantly reduce non-productive time associated with repair and maintenance. In addition, each drillship is equipped with an active-heave crane for simultaneous deployment of subsea equipment. The sum total of these and other advanced features make the drillships very attractive to our customers.

High-Specification and Premium Jack-up Rigs. Our jack-ups are capable of drilling wells to maximum depths ranging from 25,000 to 40,000 feet and in maximum water depths ranging from 300 to 550 feet, depending on rig size and location. All of our high-specification rigs are equipped with the high pressure circulation and pressure control equipment that are necessary for HPHT operations. Each of our jack-ups is designed with a hull that is fully equipped to serve as a drilling platform supported by three independently elevating legs. The rig is towed to the drilling site where the legs are lowered into and penetrate the ocean floor, and the hull raises itself out of the water up to the elevation required to drill the well using a self-contained rack and pinion system.

Our three N-Class rigs are capable of drilling well depths up to 35,000 feet in harsh environments such as the North Sea and in maximum water depths of approximately 450 feet depending on location. The N-Class rigs, which were designed for operation in the highly regulated Norwegian sector of the North Sea, can be equipped to perform drilling and production operations simultaneously. Our first N-Class rig, the Rowan Viking, was delivered in 2010, and the Rowan Stavanger and Rowan Norway were delivered in 2011.

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Our four EXL class rigs enable HPHT drilling in water depths up to 350 feet and are equipped with a hook-load capacity of two million pounds. The first three EXL class rigs were delivered in 2010, and the Rowan EXL IV was delivered in 2011.

Our three 240C class rigs were designed for HPHT drilling in water depths up to 400 feet and are equipped with a hook-load capacity of 2.5 million pounds. The Rowan Mississippi and the Ralph Coffman were added to the fleet in 2008 and 2009, respectively, and the Joe Douglas was added to the fleet in 2011.

Three of our four Super Gorilla class rigs were delivered during the period from 1998 to 2002 and are enlarged and enhanced versions of our Gorilla class rigs that can be equipped for simultaneous drilling and production operations. They can operate year-round in 400 feet of water in harsh environments such as the North Sea. The Bob Palmer, our fourth Super Gorilla class rig delivered in 2003, is an enhanced version of the Super Gorilla class jack-up designated a Super Gorilla XL. With 713 feet of leg, 139 feet more than the Super Gorillas, and 30 percent larger spud cans, the Bob Palmer can operate in water depths to 550 feet in normally benign environments like the US GOM and the Middle East or in water depths to 400 feet in hostile environments such as the North Sea.

Our four Tarzan Class rigs were delivered during the period from 2004 to 2008 and are specifically designed for deep-well, HPHT drilling in up to 300 feet of water in benign environments.

Our three Gorilla class rigs, designed in the early 1980s as a heavier-duty class of jack-up rig, are capable of operating in water depths up to 328 feet in hostile environments. The Rowan Gorilla II and III can drill to well depths of up to 30,000 feet, and the Rowan Gorilla IV is equipped to drill to 35,000 feet.

In 2015, we sold the three oldest rigs in our jack-up fleet, the Rowan Juneau and Rowan Alaska in July and the Rowan Louisiana in December. The Rowan Juneau and Rowan Alaska were sold under agreements that prohibit their future use as drilling units.

See Item 2, “Properties,” for additional information regarding our fleet.

Our operations are subject to many uncertainties and hazards. See Item 1A, “Risk Factors,” for additional information.

Contracts

Our drilling contracts generally provide for a fixed amount of compensation per day (day rate), and are either “well-to-well,” “multiple-well” or "fixed-term" generally ranging from one month to several years. Well-to-well contracts are typically cancellable by either party upon completion of drilling. Fixed-term contracts usually contain a termination provision such that either party may terminate if drilling operations are suspended for extended periods as a result of events of force majeure. While many fixed-term contracts are for relatively short periods of three months or less, many others are for one or more years, and all can continue for periods longer than the original terms. Well-to-well contracts can be extended over multiple series of wells. Many drilling contracts contain renewal or extension provisions exercisable at the option of the customer at mutually agreeable rates. Many of our drilling contracts provide for separate lump-sum payments for rig mobilization and demobilization. We recognize lump-sum fees and related expenses over the primary contract term. We recognize reimbursement of certain costs as revenues and expenses at the time they are incurred. Our contracts for work generally provide for payment in United States (U.S.) dollars except for amounts required by applicable law to be paid in the local currency or amounts required to meet local expenses.

A number of factors affect our ability to obtain contracts at profitable rates within a given region. Such factors, which are discussed further under “Competition” and in “Risk Factors” include the global economic climate, the price of oil and gas which can affect our customers' drilling budgets, over- or under-supply of drilling units, location and availability of competitive equipment, the suitability of equipment for the project, comparative operating cost of the equipment, competence of drilling personnel and other competitive factors. Profitability may also depend on receiving adequate compensation for the cost of moving equipment to drilling locations.

During periods of weak demand and declining day rates, we have historically entered into contracts at lower rates in order to keep our rigs working. At times, however, market conditions have forced us to "cold-stack" rigs to reduce costs during extended periods between contracts. During 2015, we cold-stacked three of our jack-up rigs (two in the US GOM and one in Malaysia), which remain cold-stacked.

Our contract backlog was estimated to be approximately $3.6 billion at January 20, 2016, down from approximately $5.1 billion at February 19, 2015. See “Market Outlook” in Management’s Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Form 10-K for further information with respect to our backlog.

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Competition

The contract drilling industry is highly competitive, and success in obtaining contracts involves many factors, including supply and demand for drilling units, price, rig capability, operating and safety performance, and reputation.

In the jack-up drilling market, we compete with numerous offshore drilling contractors that together have 596 marketed jack-up rigs worldwide as of February 2, 2016, inclusive of 125 units that are under construction or on order. (We define marketed rigs as all rigs that are not cold-stacked.) We estimate that 120 jack-ups, or 20 percent of the world’s marketed jack-up fleet, are high-specification, including Rowan's 19 high-specification rigs. At February 2, 2016, there were 340 marketed floaters (drillships and semi-submersibles) worldwide, inclusive of 70 units that are under construction or on order. We estimate that 170 of these floaters, or approximately 50 percent of the world’s marketed fleet, are capable of drilling in water depths of 10,000 feet or more, but only an estimated 40 floaters, or approximately 12 percent of the world's marketed fleet, have 2,500,000 pound hook-load capability and are equipped with dual blow-out preventers, which are key specifications valued by our customers.

A significant contributing factor to the softness in the offshore drilling market has been the influx of 214 newbuild jack-ups and 155 newbuild floaters delivered since early 2006. The addition of newbuild units, combined with numerous rigs having rolled off contracts in past months, has continued to increase competition, putting additional downward pressure on day rates and utilization. Of the approximately 125 jack-up rigs under construction worldwide scheduled for delivery through 2020 (38% of the currently utilized jack-up fleet of approximately 328 rigs), approximately 51 are considered high-specification (74% of the delivered high-specification fleet). Currently, there are approximately 82 competitive newbuild jack-up rigs scheduled for delivery during 2016, and only seven have contracts. For the floater market there are approximately 70 floaters under construction worldwide for delivery through 2020 (37% of the currently utilized floater fleet of approximately 188 rigs). Following the negotiated delivery delays on several units into future years, there are approximately 22 competitive newbuild floaters scheduled for delivery during 2016, and nine having contracts.

Based on the number of rigs as tabulated by IHS-Petrodata, we are the eighth largest offshore drilling contractor in the world and the fifth largest jack-up rig operator. Based on the most recent publicly available information, we are the sixth largest publicly traded offshore drilling contractor ranked by revenues. Some of our competitors have greater financial and other resources and may be more able to make technological improvements to existing equipment or replace equipment that becomes obsolete. In addition, those contractors with larger and more diversified drilling fleets may be better positioned to withstand unfavorable market conditions.

We market our drilling services to present and potential customers, including large international energy companies, smaller independent energy companies and foreign government-owned or government-controlled energy companies. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in Item 7 of this Form 10-K for a discussion of current and anticipated industry conditions and their impact on our operations.

Governmental Regulation

Many aspects of our operations are subject to governmental regulation, including equipping and operating vessels, drilling practices and methods, and taxation. In addition, the U.K., the U.S. and other countries in which we operate have regulations relating to environmental protection and pollution control. We could become liable for damages resulting from pollution of offshore waters in some circumstances, and in certain jurisdictions we must document financial responsibility.

Generally, we are indemnified under our drilling contracts for pollution, well damage and environmental damage, except in certain cases of pollution emanating above the surface of water from spills of pollutants emanating from our drilling rigs. This indemnity includes all costs associated with regaining control of a wild well, removal and disposal of pollutants, environmental remediation and claims by third parties for damages. Such contractual indemnification provisions may not, however, adequately protect us for several reasons such as (i) the contractual indemnity provisions may require us to assume a portion of the liability; (ii) our customers may not have the financial resources necessary to honor the contractual indemnity provisions; and (iii) the contractual indemnity provisions may be unenforceable under applicable law.

Our customers often require us to assume responsibility for pollution damages where we are at fault. We seek to limit our liability exposure to a non-material amount, or an amount within the limits of our available insurance coverage. For example, a contract may provide that we will assume the first $5 million of costs related to an incident resulting in wellbore pollution due to our negligence, with the customer assuming responsibility for all costs in excess of $5 million. We can provide no assurance that we will be able to negotiate indemnities and/or limitation of liability provisions for all of our contracts or that such indemnification and/or limitation of liability provisions can be enforced or will be sufficient. Our customers may challenge the validity or enforceability of the indemnity provision for several reasons, including but not limited to applicable law, judicial decisions, the language of the indemnity provision, reasons of public policy, degree of fault and/or the circumstances resulting in the pollution.

In the event of an incident resulting in wellbore pollution and we are liable for all or a portion of such event, the impact on our financial position, operations and liquidity would depend on the scope of the incident. In this instance, we would seek to enforce our legal rights, including the enforcement of the indemnity obligation and redress from all parties at fault. In addition, we maintain limited insurance for liability related to negative environmental impacts of a sudden and accidental pollution event, as described below. Such an event would adversely affect our results of operations, financial position and cash flows if both insurance and indemnity protection were unavailable or insufficient and the incident was significant.

Pursuant to the Clean Water Act, a National Pollutant Discharge Elimination Permit (NPDES permit) is required for discharges into the US GOM. As a contract driller in the US GOM, we operate in accordance with the NPDES permit regardless of the holder. According to the NPDES permit, the permit holder is the designated responsible party and is thus responsible for any environmental impacts that would occur in the event of the discharge of any unpermitted substance, including a fuel spill or oil leak from an offshore installation such as a mobile drilling unit.

Pursuant to the U.K. Offshore Directive, which went into force in 2015, we are required to have an approved Oil Pollution Emergency Plan (OPEP) for each of our drilling units operating in U.K. waters. The Offshore Directive also specifies additional regulations related to safety, licensing, environmental protection, emergency response and liability with which we comply.
Additionally, pursuant to the International Maritime Organization (IMO), we are required to have a Shipboard Oil Pollution Emergency Plan (SOPEP) for each of our drilling units. Our SOPEP establishes detailed procedures for rapid and effective response to spill events that may occur as a result of our operations or those of the operator. This plan is reviewed annually and updated as necessary. Onboard drills are conducted periodically to maintain effectiveness of the plan, and each rig is outfitted with equipment to respond to minor spills. The drills include participation of key personnel, spill response contractors and representatives of governmental agencies. For operations in the United States, our SOPEPs are subject to review and approval by various organizations including the United States Coast Guard, the EPA and the Bureau of Safety and Environmental Enforcement (BSEE), and are recertified every five years by the American Bureau of Shipping, a Recognized Organization under the IMO.

As the designated responsible party, the operator has the primary responsibility for spill response, including having contractual arrangements in place with emergency spill response organizations to supplement any onboard spill response equipment. Pursuant to our SOPEPs, we have certain resources and supplies onboard our rigs which would be used to mitigate the impact of an incident until an emergency spill response organization could deploy its resources. However, we also have an agreement with an emergency spill response organization should we have an incident that exceeds the scope of our onboard spill response equipment.

Our primary spill response provider has been in business since 1994 and specializes in helping industries prevent and clean up oil and other hydrocarbon spills throughout the Gulf Coast, with response centers in Texas and Louisiana with 24-hour response capabilities and equipment. Our provider has represented it holds all necessary licenses, certifications and permits to respond to environmental emergencies in the US GOM and maintains contacts with other response resources and organization outside the US GOM. Our provider has significant spill response resources to meet the needs of its customers.

We believe we have adequate equipment and resources available to us to respond to an emergency spill; however, we can provide no assurance that adequate resources will be available should multiple concurrent spills occur. Other jurisdictions in which we operate have similar regulations and requirements with which we comply.

We are actively involved in various industry-led initiatives and work groups, including but not limited to those of the American Petroleum Institute, the International Association of Drilling Contractors, the Ocean Energy Safety Institute, and the British Rig Owners Association, which are intended to improve safety and protect the environment.

Oil and gas operations in the US GOM and in many of the international locations in which we operate are subject to regulation with respect to well design, casing and cementing and well control procedures, as well as rules requiring operators to systematically identify risks and establish safeguards against those risks through a comprehensive safety and environmental management system, or SEMS. Any serious oil and gas industry related event heightens governmental and environmental concerns and may lead to legislative proposals being introduced which may materially limit or prohibit offshore drilling in certain areas. New regulations continue to be implemented, including rules regarding drilling systems and equipment, such as blowout preventer and well-control systems and lifesaving systems, as well as rules regarding employee training, engaging personnel in safety management and requiring third-party audits of SEMS programs.

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The BSEE has announced proposed regulations to govern multiple aspects of the design, inspection, testing and functionality of blowout preventers. The Blowout Preventer Systems and Well Control Rule began an open comment period on April 15, 2015. BSEE submitted the new rule to the Office of Management and Budget on January 29, 2016, for review prior to publication in the Federal Register. Such new regulations may require modifications or enhancements to existing systems and equipment or require new equipment and could increase our operating costs and cause downtime for our offshore drilling units if we are required to take any of them out of service between scheduled surveys or inspections, or if we are required to extend scheduled surveys or inspections to meet any such new requirements. Additional governmental regulations concerning licensing, taxation, equipment specifications, training requirements or other matters could increase the costs of our operations and could reduce exploration activity in the areas in which we operate.

Except as discussed above, we do not believe regulatory compliance has materially affected our capital expenditures, earnings or competitive position to date, although such measures increase drilling costs and may adversely affect drilling operations. Further regulations may reasonably be anticipated, but any effects on our drilling operations cannot be accurately predicted at this time.

We operate in areas where regulatory requirements govern the protection of employee occupational health and working environments.

In addition to regulations that directly affect our operations, regulations associated with the production and transportation of oil and gas affect our customers and thereby could potentially impact demand for our services.

Insurance

We maintain insurance coverage for damage to our drilling rigs, third-party liability, workers’ compensation and employers’ liability, sudden and accidental pollution and other types of loss or damage. Our insurance coverage is subject to deductibles and self-insured retentions which must be met prior to any recovery. Additionally, our insurance is subject to exclusions and limitations, and we can provide no assurance that such coverage will adequately protect us against liability from all potential consequences and damages.

Our current insurance policies provide coverage for loss or damage to our fleet of drilling rigs on an agreed value basis (which varies by unit) subject to a deductible of either $25 million or $15 million per occurrence, depending on the unit's geographic location. This coverage does not include damage to our rigs arising from a US GOM named windstorm, for which we are self-insured.

We maintain insurance policies providing limited coverage for liability associated with negative environmental impacts of a sudden and accidental pollution event, third-party liability, employers’ liability (including Jones Act liability) and automobile liability, and these policies are subject to various exclusions, deductibles and underlying limits. In addition, we maintain excess liability coverage with an annual aggregate limit of $700 million subject to a self-insured retention of $10 million except for liabilities (including removal of wreck) arising out of a US GOM named windstorm, which are subject to a self-insured retention of $200 million.

Our rig physical damage and liability insurance renews each June. We can provide no assurance we will be able to secure coverage of a similar nature with similar limits at comparable costs.

Employees

At December 31, 2015, we had 3,496 employees worldwide, compared to 4,051 and 3,499 at December 31, 2014 and 2013, respectively. Certain of our employees and contractors in international markets, such as Trinidad and Norway, are represented by labor unions and work under collective bargaining or similar agreements, which are subject to periodic renegotiation. We consider relations with our employees to be satisfactory.

Customers

In 2015, Saudi Aramco, ConocoPhillips and Anadarko accounted for 19%, 13%, and 10%, respectively, of consolidated revenues.

Reports filed with or furnished to the SEC

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (the Exchange Act) are made available free of charge on our website at www.rowan.com as soon as reasonably practicable after we electronically file such

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material with, or furnish it to, the SEC. Information contained on or accessible from our website is not incorporated by reference into this Form 10-K and should not be considered a part of this report or any other filing that we make with the SEC.

ITEM 1A. RISK FACTORS

You should consider carefully the following risk factors, in addition to the other information contained and incorporated by reference in this Form 10-K, before deciding to invest in our equity or debt securities.

Our business depends solely on the level of activity in the offshore oil and gas industry. Adverse developments affecting the industry, including declines in oil or gas prices and reduced demand for oil and gas products, have an adverse effect on our business, financial condition and results of operations.

Demand for drilling services depends heavily on a variety of economic and political factors and the level of oil and gas activity worldwide. Sustained declines in oil or natural gas prices such as we have been experiencing since mid-2014, combined with market expectations of a prolonged weakened global market, have caused oil and gas companies to significantly reduce their exploration, development and production activities, thereby decreasing demand for offshore drilling services and leading to lower rig utilization and day rates for our services. Oil and natural gas prices have historically been very volatile, and our drilling operations have in the past suffered through long periods of weak market conditions.

Demand for our drilling services depends on many factors beyond our control, including:

- worldwide demand for and prices of oil and natural gas, and expectations regarding future energy prices;
- the supply of drilling units in the worldwide fleet versus demand;
- the level of exploration and development expenditures by energy companies and the ability to raise capital;
- the willingness and ability of the Organization of Petroleum Exporting Countries (OPEC) to limit production levels and influence prices;
- the level of production in non-OPEC countries;
- the effect of economic sanctions that affect the energy industry;
- the general economy, including inflation and changes in the rate of economic growth;
- the condition of global capital markets;
- adverse sea, weather and climate conditions in our principal operating areas, including possible disruption of exploration and development activities due to loop currents, hurricanes and other severe sea and weather conditions;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- environmental and other laws and regulations;
- policies of various governments regarding exploration and development of oil and natural gas reserves;
- nationalization and/or confiscation;
- worldwide tax policies;
- political and military conflicts in oil-producing areas and the effects of terrorism;
- increased supply of oil and gas from onshore hydraulic fracturing and shale development and relative cost of offshore drilling versus onshore oil and gas production;
- the development and exploitation of alternative fuels and energy sources, and
- merger, divestiture, restructuring and consolidation of our customers and competitors and their assets.

Adverse developments affecting the industry as a result of one or more of these factors, including a decline in oil or gas prices (such as the decline since mid-2014, any further decline, or the failure of oil or gas prices to recover from their current levels),

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a global recession, continued declines in demand for oil and gas products, increased oversupply of drilling units, and increased regulation of drilling and production, would adversely affect our business, financial condition and results of operations.

The success of our business is dependent upon our ability to secure contracts for our drilling units at sufficient day rates. Depressed oil and gas prices and an oversupply of drilling units have led to further reductions in rig utilization and day rates, which may materially impact our profitability.

Our ability to meet our cash flow obligations depends on our ability to secure ongoing work for our drilling units at sufficient day rates. As of January 20, 2016, we had nine jack-up drilling units without contracts (including three cold-stacked); six with contract terms ending in 2016; four with contract terms ending in 2017; seven with contract terms ending in 2018; and one with a contract term ending in 2024. Three of our drillships have contracts ending in 2017 and one ends in early 2018. Given current market conditions, it is likely that future demand for offshore drilling units and day rates will continue to decline for an extended period of time. Failure to secure profitable contracts for our drilling units could negatively impact our operating results and financial position, impair our ability to generate sufficient cash flow to fund our capital expenditures and/or meet our other obligations.

Prior to the recent downturn in the drilling sector, the industry experienced a significant increase in construction activity. This increase in supply of newbuild drilling units, combined with the decrease in demand for offshore drilling services, has resulted in an oversupply of drilling units and a resulting decline in utilization and day rates that is expected to continue for an extended period of time. According to industry sources, there were 596 marketed jack-up rigs worldwide as of February 2, 2016, inclusive of 125 units that are under construction or on order and 340 marketed floaters (drillships and semi-submersible) worldwide, inclusive of 70 units that are under construction or on order. (We define marketed rigs as all rigs that are not cold-stacked.) A continued decline in utilization and day rates would further impact our revenues and profitability.

A further decline in the market for contract drilling services could result in additional asset impairment charges.

We recognized asset impairment charges on our jack-up drilling units aggregating approximately $566 million in 2014 and $330 million in 2015, or approximately 7% and 4%, respectively, of our fixed asset carrying values. Prolonged periods of low utilization and day rates, the cold-stacking of idle assets, or the sale of assets below their then carrying value could result in the recognition of additional impairment charges on our drilling units if future cash flow estimates, based upon information available to management at the time, indicate that their carrying value may not be recoverable. See “Impairment of Long-lived Assets” in Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

We are subject to operating risks that could result in environmental damage, property loss, personal injury, death, business interruptions and other losses.

Our drilling operations are subject to many operational hazards such as blowouts, explosions, fires, collisions, punch-throughs (i.e., when one leg of a jack-up rig breaks through the hard crust of the ocean floor, placing stress on the other legs), mechanical or technological failures, navigation errors, or equipment defects that could increase the likelihood of accidents. Accidents can result in:

- serious damage to or destruction of property and equipment;
- personal injury or death;
- costly delays or cancellations of drilling operations;
- interruption or cessation of day rate revenue;
- uncompensated downtime;
- reduced day rates;

- significant impairment of producing wells, leased properties, pipelines or underground geological formations;
- damage to fisheries and pollution of the marine and coastal environment; and
- fines and penalties.

Our drilling operations are also subject to marine hazards, whether at drilling sites or while equipment is under tow, such as a vessel capsizing, sinking, colliding or grounding. In addition, raising and lowering jack-up rigs and drilling into high-pressure formations are complex, hazardous activities, and we periodically encounter problems. Any ongoing change in weather or sea patterns or climate conditions could increase the adverse impact of marine hazards.

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In past years, we have experienced some of the types of incidents described above, including punch-throughs and towing accidents resulting in lost or damaged equipment and high-pressure drilling accidents resulting in lost or damaged formations. Any future such events could result in operating losses and have a significant impact on our business.

The global nature of our operations involves additional risks, particularly in certain foreign jurisdictions.

Our operations are significantly diversified internationally. Foreign operations are often subject to additional political, economic and other uncertainties, such as with respect to taxation policies, customs restrictions, local content requirements, regulatory requirements, currency convertibility and repatriation, security threats including terrorism, piracy, and the risk of asset expropriation. Political unrest and regulatory restrictions could halt operations or impact us in other unforeseen ways. There have been recent political discussions regarding the possibility of the United Kingdom exiting the European Union. Should that occur, our business and operations in the UK and elsewhere could be impacted.

Many countries have regulations or policies requiring or rewarding the participation of local companies and individuals in the petroleum-related activities. Such participation requirements can include, without limitation, the ownership of oil and gas concessions, the hiring of local agents and partners, the procurement of goods and services from local sources, and the employment of local workers. The requirements can also include ownership of our drilling units, in whole or in part, by home country companies or citizens and /or require reflagging of our drilling units under the flag of the home country. The governments of many of these foreign countries have become increasingly active in requiring higher levels of local participation which may increase our costs and risks of operating in these regions, thereby limiting our ability to enter into, relocate from, or compete in these regions.

In addition, our inability to obtain visas and work permits for our employees in foreign jurisdictions on a timely basis could delay or interrupt our operations resulting in an adverse impact on our business. Further, governmental restrictions in some jurisdictions may make it difficult for us to move our personnel, assets and operations in and out of these regions without delays or downtime.

In foreign areas where legal protections may be less available to us, we assume greater risk that our customer may terminate contracts without cause on short notice, contractually or by governmental action. Additionally, operations in certain areas, such as the North Sea and US GOM, are highly regulated and have higher compliance and operating costs in general.

Although we are a U.K. company, a significant majority of our revenues and expenses are transacted in U.S. dollars, which is our functional currency. However, in certain countries in which we operate, local laws or contracts may require us to receive some portion of payment in the local currency. We are exposed to foreign currency exchange risk to the extent the amount of our monetary assets denominated in the foreign currency differs from our obligations in that foreign currency. In order to mitigate the effect of exchange rate risk, we attempt to limit foreign currency holdings to the extent they are needed to pay liabilities denominated in the foreign currency. At December 31, 2015, we held Egyptian pounds in the amount of $13.5 million. We ceased drilling operations in Egypt in 2014, and are currently working to obtain access to the funds for use outside Egypt to the extent they are not utilized; however, we can provide no assurance we will be able to convert or utilize such funds in the future.

The offshore drilling industry is highly competitive and cyclical, with intense price competition.

The offshore contract drilling industry is a highly competitive and cyclical business characterized by numerous competitors, high capital and operating costs and evolving capability of newer rigs. Drilling contracts are often awarded on a competitive-bid basis, and intense price competition, rig availability, location and suitability, experience of the workforce, efficiency, safety performance record, technical capability and condition of equipment, operating integrity, reputation, industry standing and client relations are all factors in determining which contractor is awarded a contract. Our future success and profitability will partly depend upon our ability to keep pace with our customers' demands with respect to these factors.

In addition to intense competition, our industry has historically been cyclical. The contract drilling industry is currently in a period of low demand for drilling services, excess rig supply, a prolonged period of declining oil and gas prices and reduced worldwide drilling activity. These conditions have intensified the competition in the industry and put downward pressure on day rates. As a result, we may be unable to secure profitable contracts for our drilling units, we may have to contract our rigs at substantially lower rates for long periods of time, enter into nontraditional fee arrangements, or idle or cold-stack some of our drilling units, all of which would adversely affect our operating results, cash flows and financial position.

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We will experience reduced profitability if our customers terminate or seek to renegotiate our drilling contracts, and our backlog of contracts may not be ultimately realized.

We may be subject to the increased risk of our customers seeking to terminate or renegotiate their contracts. Our customers' ability to perform their obligations under drilling contracts with us may also be adversely affected by their own financial position, restricted credit markets and the current industry downturn. If our customers cancel or are unable to renew some of their contracts and we are unable to secure new contracts on a timely basis and on substantially similar terms, if contracts are disputed or suspended for an extended period of time, or if a number of our contracts are renegotiated, such events would adversely affect our business, financial condition and results of operations.
Most of our term drilling contracts are cancelable by the customer without penalty upon the occurrence of events beyond our control such as the loss or destruction of the drilling unit, or the suspension of drilling operations for a specified period of time as a result of a breakdown of major equipment. While most of our contracts require the customer to pay a termination fee in the event of an early cancellation without cause, early termination payments will not fully compensate us for the loss of the contract, and could result in the drilling unit becoming idle or cold-stacked for an extended period of time. If we or our customers are unable to perform under existing contracts for any reason or replace terminated contracts with new contracts having less favorable terms, our backlog of estimated revenues would decline, adversely affecting our financial results.

We must make substantial capital and operating expenditures to build, maintain, and upgrade our drilling fleet.

Our business is highly capital intensive and dependent on having sufficient cash flow and or available sources of financing in order to fund our capital expenditure requirements. We can provide no assurance that we will have access to adequate or economical sources of capital to fund our capital expenditures.

We have and will likely continue to have certain customer concentrations, and the loss of a significant customer would adversely impact our financial results.

A concentration of customers increases the risks associated with any possible (i) termination or nonperformance of drilling contracts, (ii) failure to renew contracts or award new contracts, or (iii) reduction of our customers' drilling programs. In 2015, Saudi Aramco, ConocoPhillips, and Anadarko accounted for 19%, 13% and 10%, respectively, of our consolidated revenues. The loss or material reduction of business from a significant customer would have an adverse impact on our results of operations and cash flows. Moreover, to the extent that we may be heavily dependent on any single customer, we could be subject to the risks faced by that customer to the extent that such risks impede the customer's ability to continue operating and make timely payments to us. In addition, due to the high day rate and longer-term nature of our drillship contracts, a loss of any of our drillship customers would adversely affect our results of operations and cash flows.

Construction upgrades, enhancements, conversions, mobilizations and repairs of rigs and drillships are subject to risks, including delays and cost overruns, which could have an adverse impact on our financial position, results of operations and cash flows.

From time to time as our drilling units age, we may be required to make significant upgrade, refurbishment or repair expenditures for our fleet or undertake new construction projects. Mobilization of existing units and initial operations of new drilling units often result in delays and other complications that could result in significant unexpected costs, uncompensated downtime, reduced day rates or the cancellation or termination of drilling contracts. Further, we may be required to pay up front for our own mobilization or upgrade costs in order to obtain a contract on a drilling unit. Some of the costs associated with upgrades, enhancements, conversions, mobilizations and repairs of drilling units could be unplanned and are subject to risks of cost overruns or delays as a result of numerous factors, including the following:

- shipyard unavailability;
- shortages of equipment, materials or skilled labor for completion of repairs or upgrades to our equipment;
- unscheduled delays in the delivery or cost increases of materials and equipment or in shipyard construction;
- failure of equipment to meet, design, quality or performance standards;
- loss of or damage to essential equipment while in transit;
- financial or operating difficulties experienced by equipment vendors or the shipyard;

- unanticipated actual or purported change orders;
- local customs strikes or related work slowdowns that could delay importation of equipment or materials;
- engineering problems, including those relating to the commissioning of newly designed equipment;
- design or engineering changes;
- latent damages or deterioration to the hull, equipment and machinery in excess of engineering estimates and assumptions;
- work stoppages;
- client acceptance delays;
- weather interference, storm damage or other events of force majeure;
- disputes with shipyards and suppliers;
- inability or unwillingness of shipyards and suppliers to honor warranty obligations;
- long lead-times for replacement of equipment;
- shipyard failures and difficulties;
- failure of third-party equipment vendors or service providers;
- unanticipated cost increases, including relating to raw materials used in construction of our drilling units; and
- difficulty in obtaining necessary permits or approvals or in meeting permit or approval conditions.

These factors may contribute to cost variations or delays. Such delays may, in some circumstances, result in a delay in contract commencement, resulting in a loss of revenue to us or payment for liquidated damages, and may also cause customers to renegotiate, terminate or shorten the term of a drilling contract pursuant to applicable late delivery clauses. In the event of termination of a contract, we may not be able to secure a replacement contract on as favorable terms or at all. Additionally, unexpected capital expenditures for upgrades, refurbishment and construction projects could materially exceed our planned capital expenditures. Moreover, our drilling units that may undergo upgrade, refurbishment or repair may not earn a day rate during the periods they are out of service. Furthermore, the inability or unwillingness of shipyards and suppliers to honor warranty obligations may result in additional costs to us. The occurrence of any of these events would adversely affect our results of operations, financial position or cash flows.

If we or our customers are unable to acquire or renew permits and approvals required for drilling operations, we may be forced to suspend or cease our operations, and our profitability may be reduced.

Crude oil and natural gas exploration and production operations require numerous permits and approvals for us and our customers from governmental agencies in the areas in which we operate. In addition, many governmental agencies have increased regulatory oversight and permitting requirements in recent years. If we or our customers are not able to obtain necessary permits and approvals in a timely manner, our operations will be adversely affected. Obtaining all necessary permits and approvals may necessitate substantial expenditures to comply with the requirements of these permits and approvals, future changes to these permits or approvals, or any adverse change in the interpretation of existing permits and approvals. In addition, such regulatory requirements and restrictions could also delay or curtail our operations, require us to make substantial expenditures to meet compliance requirements, and could have a significant impact on our financial condition or results of operations and may create a risk of expensive delays or loss of value if a project is unable to function as planned.

For example, the Bureau of Ocean Energy Management and the Bureau of Safety and Environmental Enforcement, have implemented significant environmental and safety regulations applicable to drilling operations in the US GOM. These regulations have at times adversely impacted the ability of our customers to obtain necessary permits and approval on a timely basis and/or to continue operations uninterrupted under existing permits.

Increases in regulatory requirements could significantly increase our costs or delay our operations.

Many aspects of our operations are subject to governmental regulation, including equipping and operating vessels, drilling practices and methods, and taxation. For example, operations in certain areas, such as the US GOM and the

North Sea, are highly regulated

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and have higher compliance and operating costs in general. We may be required to make significant expenditures in order to comply with existing or new governmental laws and regulations. It is also possible that such laws and regulations may in the future add significantly to our operating costs or result in a reduction of revenues associated with downtime required to implement regulatory requirements.

Oil and gas operations in the US GOM and in many of the international locations in which we operate are subject to regulation with respect to well design, casing and cementing and well control procedures, as well as rules requiring operators to systematically identify risks and establish safeguards against those risks through a comprehensive safety and environmental management system, or SEMS. New regulations continue to be implemented, including rules regarding drilling systems and equipment, such as blowout preventer and well-control systems and lifesaving systems, as well as rules regarding employee training, engaging personnel in safety management and requiring third-party audits of SEMS programs. Such new regulations may require modifications or enhancements to existing systems and equipment, or require new equipment, and could increase our operating costs and cause downtime for our units if we are required to take any of them out of service between scheduled surveys or inspections, or if we are required to extend scheduled surveys or inspections to meet any such new requirements. Additional governmental regulations concerning licensing, taxation, equipment specifications, training requirements or other matters could increase the costs of our operations and could reduce exploration activity in the areas in which we operate.

Governments in some countries are increasingly active in regulating and controlling the ownership of concessions, the exploration for oil and gas, and other aspects of the oil and gas industry. These governmental regulations may limit or substantially increase the cost of drilling activity in an operating area generally. The modification of existing laws or regulations or the adoption of new laws or regulations curtailing exploratory or developmental drilling for oil and gas for economic, environmental or other reasons could materially and adversely affect our operations by limiting drilling opportunities.

Governments around the world are beginning to adopt laws and regulations regarding climate change. Lawmakers and regulators in the U.S., the U.K. and other jurisdictions where we operate have focused increasingly on restricting and reporting the emission of carbon dioxide, methane and other “greenhouse” gases that may contribute to warming of the Earth’s atmosphere and other climatic changes. This may result in new environmental regulations that may unfavorably impact us, our suppliers and our customers. We may be exposed to risks related to new laws, regulations, treaties or international agreements pertaining to climate change, greenhouse gases, carbon emissions or energy use that could decrease the use of oil or natural gas, thus reducing demand for hydrocarbon-based fuel and our drilling services. Governments may also pass laws or regulations incentivizing or mandating the use of alternative energy sources such as wind power and solar energy, which may reduce demand for oil and natural gas and our drilling services. Such laws, regulations, treaties or international agreements could result in increased compliance costs or additional operating restrictions, which may have a negative impact on our business, and could adversely affect our operations by limiting drilling opportunities.

In addition, the offshore drilling industry is highly dependent on demand for services from the oil and gas industry and accordingly, regulations of the production and transportation of oil and gas generally could impact demand for our services.

Our drilling units are subject to damage or destruction by severe weather, and our drilling operations may be affected by severe weather conditions.

Our drilling rigs are located in areas that frequently experience hurricanes and other forms of severe weather conditions. These conditions can cause damage or destruction to our drilling units. Further, high winds and turbulent seas can cause us to suspend operations on drilling units for significant periods of time. Even if our drilling units are not damaged or lost due to severe weather, we may experience disruptions in our operations due to evacuations, reduced ability to transport personnel to the drilling unit, or damage to our customers’ platforms and other related facilities. Additionally, our customers may not choose to contract our rigs for use during hurricane season, particularly in the US GOM. Future severe weather could result in the loss or damage to our rigs or curtailment of our operations, which could adversely affect our financial position, results of operations and cash flows.

Taxing authorities may challenge our tax positions, and we may not be able to realize expected benefits.

Current tax laws and regulations in many jurisdictions and treaties among various countries are currently under review or negotiation. Changes to these laws or interpretations could affect the taxes we pay in various jurisdictions. Our tax positions are subject to audit by relevant tax authorities who may disagree with our interpretations or assessments of the effects of tax laws, treaties, or regulations, or their applicability to our corporate structure or certain of our transactions we have undertaken. We could therefore incur material amounts of unrecorded income tax cost if our positions are challenged and we are unsuccessful in defending them.

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Changes in or non-compliance with tax laws and changes to our income tax estimates could adversely impact our financial results.

In 2012, we changed our legal domicile to the U.K. There are legislative proposals in the U.S. that attempt to treat companies that have undertaken similar transactions as U.S. corporations subject to U.S. taxes or to limit the tax deductions or tax credits available to U.S. subsidiaries of these corporations. The realization of the expected tax benefits of our redomestication could be impacted by changes in tax laws, tax treaties or tax regulations or the interpretation or enforcement thereof or differing interpretation or enforcement of applicable law by the IRS or other tax authorities. Changes in our effective tax rates as determined from time to time, the inability to realize anticipated tax benefits, or the imposition of additional taxes could have a material impact on our results of operations, financial position and cash flows. Our future effective tax rates could be adversely affected by changes in the valuation of our deferred tax assets and liabilities, the ultimate repatriation of earnings from the non-U.S. subsidiaries of Rowan Companies Inc. (RCI), a wholly owned, indirect subsidiary of the Company, to RCI, or by changes in applicable regulations and accounting principles.

Changes in our recorded tax estimates (including estimated reserves for uncertain tax positions) may have a material impact on our results of operations, financial position and cash flows. We do not provide for deferred income taxes on undistributed earnings of our non-U.K. subsidiaries, including RCI's non-U.S. subsidiaries. It is our policy and intention to permanently reinvest earnings of non-U.S. subsidiaries of RCI outside the U.S. Should the non-U.S. subsidiaries of RCI make a distribution from these earnings, we may be subject to additional U.S. income taxes.

Political disturbances, war, or terrorist attacks and changes in global trade policies and economic sanctions could adversely impact our operations.

Our operations are subject to political and economic risks and uncertainties, including instability resulting from civil unrest, political demonstrations, mass strikes, or an escalation or additional outbreak of armed hostilities or other crises in oil or natural gas producing areas, which may result in extended business interruptions, suspended operations and danger to our employees, or result in claims by our customers of a force majeure situation and payment disputes. Additionally, we are subject to risks of terrorism, piracy, political instability, hostilities, expropriation, confiscation or deprivation of our assets or military action impacting our operations, assets or financial performance in many of our areas of operations.

Operating and maintenance costs of our drilling units may be significant, and could have an adverse effect on the profitability of our contracts. In addition, operational interruptions or maintenance or repair work may cause our customers to suspend or reduce payment of day rates until operation is resumed, which may lead to loss of revenue or termination or renegotiation of the drilling contract.

Most of our drilling contracts provide for the payment of a fixed day rate during periods of operation and reduced day rates during periods of other activities. Given current market conditions, we may not be able to negotiate day rates sufficient to cover increased or unanticipated costs. Our operating expenses and maintenance costs can be unpredictable, and depend on a variety of factors including: crew costs, costs of provisions, equipment, insurance, maintenance and repairs, customer and regulatory requirements, and shipyard costs, many of which are beyond our control. Our profit margins may therefore vary over the terms of our contracts, which could adversely affect our financial position, results of operations and cash flows.

Our customers may be entitled to pay a waiting, or standby, rate lower than the full operational day rate if a drilling unit is idle for reasons that are not related to the ability of the rig to operate. In addition, if a drilling unit is taken out of service for maintenance and repair for a period of time exceeding the scheduled maintenance periods set forth in the drilling contract, we may not be entitled to payment of day rates until the unit is able to work. If the interruption of operations were to exceed a determined period, our customers may have the right to pay a rate that is significantly lower than the waiting rate for a period of time, and, thereafter, may terminate the drilling contracts related to the subject rig. Suspension of drilling contract payments, prolonged payment of reduced rates or termination of any drilling contract as a result of an interruption of operations could materially adversely affect our business, financial condition and results of operations.

Our rig operating and maintenance costs include fixed costs that will not decline in proportion to decreases in rig utilization and day rates.

We do not expect our rig operating and maintenance costs to decline proportionately when rigs are not in service or when day rates decline. Fixed costs continue to accrue during out-of-service periods (such as shipyard stays and rig mobilizations preceding a contract), which represented approximately 2.7% of our available rig days in 2015. Operating revenue may fluctuate as rigs are recontracted at prevailing market rates upon termination of a contract, but costs for operating a rig are generally fixed or only slightly variable regardless of the day rate being earned. Additionally, if our rigs are idle between contracts, we typically continue to incur operating and personnel costs because the crew is retained to prepare the rig for its next contract. During times of reduced activity, reductions in costs may not be immediate as some crew members may be required to assist in the rig's removal from service. Moreover, as our rigs are mobilized from one geographic location to another, the labor and other operating and maintenance costs may increase significantly.

Supplier capacity constraints or shortages in parts or equipment, supplier production disruptions, supplier quality and sourcing issues or price increases could increase our operating costs, decrease our revenues and adversely impact our operations.

Our reliance on third-party suppliers, manufacturers and service providers to secure equipment used in our drilling operations exposes us to volatility in the quality, price and availability of such items. Certain specialized parts and equipment we use in our operations may be available only from a single or small number of suppliers. A disruption in the deliveries from such third-party suppliers, capacity constraints, production disruptions, price increases, defects or quality-control issues, recalls or other decreased availability or servicing of parts and equipment could adversely affect our ability to meet our commitments to customers, adversely impact our operations and revenues by resulting in uncompensated downtime, reduced day rates or the cancellation or termination of contracts, or increase our operating costs.

We may have difficulty obtaining or maintaining insurance in the future, and some of our losses may not be covered by insurance.

We maintain insurance coverage for damage to our drilling rigs, third-party liability, workers' compensation and employers' liability, sudden and accidental pollution, and other types of loss or damage. There are some losses, however, for which insurance may not be available or only available at much higher prices. For example, we do not currently maintain named windstorm physical damage coverage on any of our drilling units located in the US GOM. Our insurance coverage is subject to deductibles and self-insured retentions which must be met prior to any recovery. Additionally, our insurance is subject to exclusions and limitations.

Our insurance program provides coverage for loss or damage to our drilling units on an agreed value basis (which varies by unit) subject to a deductible of $25 million per occurrence. This coverage does not include damage arising from a US GOM named windstorm, for which we are self-insured.

We also maintain insurance policies providing coverage for liability associated with negative environmental impacts of a sudden and accidental pollution event, third-party liability, employers' liability (including Jones Act liability), and automobile liability. These policies are also subject to various exclusions, deductibles and underlying limits. We maintain excess liability coverage with an annual aggregate limit of $700 million subject to a self-insured retention of $10 million, except for liabilities (including removal of wreck) arising out of US GOM named windstorms, which are subject to a self-insured retention of $200 million per occurrence.

We can provide no assurance that our insurance coverage will adequately protect us against liability from potential consequences and damages, or that we will be able to maintain adequate insurance in the future. A significant event which is not adequately covered by insurance and /or the failure of one or more of our insurance providers to meet claim obligations or losses or liabilities resulting from uninsured or underinsured events could adversely affect our financial position, results of operations and cash flows.

Our contractual indemnification provisions may not be sufficient to cover our liabilities.

Our drilling contracts provide for varying levels of indemnification and allocation of liabilities between our customers and us with respect to liabilities resulting from various hazards associated with the drilling industry, such as loss of well control, well-bore pollution and damage to subsurface reservoirs and injury or death to personnel. The degree of indemnification we receive from operators against liabilities varies from contract to contract based on market conditions and customer requirements existing when the contract was negotiated. Our drilling contracts generally indemnify us for injuries and death of our customers' employees and loss or damage to our customers' property. Our service agreements generally indemnify us for injuries and death of our service providers' employees. However, the enforceability of our indemnities may be subject to differing interpretations, or further limited or prohibited under applicable law or by contract, particularly in cases of gross negligence, willful misconduct, punitive damages or punitive fines and/or penalties. For example, in 2012 a U.S. District Court in the Eastern District of Louisiana invalidated certain contractual indemnities for punitive damages and for civil penalties in a drilling contract governed by U.S. maritime law as a matter of public policy. We could therefore be liable for certain liabilities even in cases where we have contractual indemnification rights. Notwithstanding a contractual indemnity from a customer, there can be no assurance that our customers will be financially able to indemnify us or will otherwise honor their contractual indemnity obligations. The failure of a customer

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to meet its indemnification obligations, or losses or liabilities resulting from events excluded from or unenforceable under contractual indemnification obligations would adversely affect our financial position, results of operations and cash flows.

Failure to retain highly skilled personnel could hurt our operations.

We require highly skilled and experienced personnel to operate our rigs and provide technical services and support for our operations. In the past, during periods of high demand for drilling services and increasing worldwide industry fleet size, shortages of qualified personnel have occurred. Such shortages could result in our loss of qualified personnel to competitors, impair the timeliness and quality of our work and create upward pressure on costs. If we are unable to retain or train skilled personnel, our operations and quality of service could be adversely impacted.

We are involved in litigation and legal proceedings from time to time that could have a negative effect on us if determined adversely.

We are, from time to time, involved in various legal proceedings, which may include, among other things, contract disputes, personal injury, environmental, toxic tort, employment, tax and securities litigation, governmental investigations or proceedings, and litigation that arises in the ordinary course of our business. Although we intend to defend any of these matters vigorously, we cannot predict with certainty the outcome or effect of any claim or other litigation matter. Our profitability may be adversely affected by the outcome of claims or contract disputes, including any inability to collect receivables or resolve significant contractual or day rate disputes, and any purported nullification, cancellation or breach of contracts with customers or other parties. Litigation may have an adverse effect on us because of potential negative outcomes, the costs associated with defending the lawsuits, the diversion of resources, reputational damage, and other factors.

Our ability to access the credit and debt capital markets may be restricted. We may experience a downgrade in our credit ratings.

Our ability to maintain a sufficient level of liquidity to meet our financial and operating needs is dependent upon our future performance, operating cash flows, and our access to credit and debt capital markets. In turn, our level of liquidity and access to credit and debt capital markets depends on general economic conditions, industry cycles, financial, business and other factors affecting our operations, as well as our credit ratings. Tightening in the credit markets due to the current economic environment and concerns about the offshore drilling industry may restrict our access to the credit and debt capital markets and increase the cost of such indebtedness. Our future cash flows and access to capital may be insufficient to meet all of our capital requirements, debt obligations and contractual commitments, and any insufficiency could have an adverse impact on our business.

Credit rating agencies may also downgrade our credit ratings to non-investment grade levels at any time. A downgrade in our ratings below investment grade could have adverse consequences on our business and future prospects, including the following:

- Restrict our ability to access credit and debt capital markets;
- Cause us to refinance or issue debt with less favorable terms and conditions;
- Pay increased fees under our debt agreements;
- Negatively impact current and prospective customers’ willingness to transact business with us;
- Impose additional insurance, guarantee and collateral requirements; or
- Limit our access to bank and third-party guarantees, surety bonds and letters of credit.

We depend heavily upon the security and reliability of our technology systems and those of our service providers, and such systems are subject to cybersecurity risks and threats.

We depend heavily on technologies, systems and networks that we manage, and others that are managed by our third-party service and equipment providers, to conduct our business and operations. Cybersecurity risks and threats to such systems continue to grow in sophisticated ways that avoid detection and may be difficult to anticipate, prevent or mitigate. If any of our or our service or equipment providers' security systems for protecting against cybersecurity breaches or failures prove to be insufficient, we could be adversely affected by having our business and financial systems compromised, our companies', employees', vendors' or customers' confidential or proprietary information altered, lost or stolen, or our (or our customers') business operations or safety procedures disrupted, degraded or damaged. A breach or failure could also result in injury (financial or otherwise) to people, loss of control of, or damage to, our (or our customers') assets, harm to the environment, reputational damage, breaches of laws or regulations, litigation and other legal liabilities. In addition, we may incur significant costs to prevent, respond to or mitigate cybersecurity risks or events and to defend against any investigations, litigation or other proceedings that may follow such events. Such a failure or breach of our systems could adversely and materially impact our business operations, financial position, results of operations and cash flows.

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Technology disputes could negatively impact our operations or increase our costs.
Drilling rigs use proprietary technology and equipment which can involve potential infringement of a third party's rights, including patent rights. The majority of the intellectual property rights relating to our jack-ups and drillships are owned by us or our suppliers or sub-suppliers, however, in the event that we or one of our suppliers or sub-suppliers becomes involved in a dispute over infringement rights relating to equipment owned or used by us, we may lose access to repair services or replacement parts, or we could be required to cease use of some equipment or forced to modify our jack-ups or drillships. We could also be required to pay license fees or royalties for the use of equipment. Technology disputes involving us or our suppliers or sub-suppliers could adversely affect our financial results and operations.
Transocean holds U.S. and other patents for dual activity drilling equipment and has pursued litigation against several other offshore drilling contractors. Transocean could choose to sue us or our customers for infringing its patents if it believes that we are using technology covered by its patent on our drillships, and we could be forced to modify our drillships and/or pay royalties to Transocean in the event that a Court were to find that any Transocean patents are infringed.

Failure to comply with anti-corruption and anti-bribery laws could result in fines, criminal penalties and drilling contract terminations and could have an adverse impact on our business.

The U.S. Foreign Corrupt Practices Act (FCPA), the U.K. Bribery Act 2010 (UK Bribery Act) and similar laws in other jurisdictions generally prohibit companies and their intermediaries from making improper payments to foreign officials for the purpose of obtaining or retaining business. We have operated and may in the future operate in parts of the world where strict compliance with anti-corruption and anti-bribery laws may conflict with local customs and practices. Any failure to comply with the FCPA, UK Bribery Act, or other anti-corruption laws due to our own acts or omissions or the acts or omissions of others, including our partners, agents or vendors, could subject us to civil and criminal penalties or other sanctions, which would adversely affect our business, financial position, results of operations or cash flows. We could also face fines, sanctions and other penalties from authorities in the relevant foreign jurisdictions, including prohibition of our participation in or curtailment of business operations in those jurisdictions and the seizure of drilling units or other assets.

Unionization efforts and labor regulations in certain countries in which we operate could materially increase our costs or limit our flexibility.

Certain of our employees and contractors in international markets such as Trinidad and Norway are represented by labor unions and work under collective bargaining or similar agreements, which are subject to periodic renegotiation. Further, efforts may be made from time to time to unionize other portions of our workforce. In addition, we have experienced, and in the future may experience, strikes or work stoppages and other labor disruptions. Additional unionization efforts, new collective bargaining agreements or work stoppages could materially increase our costs, reduce our revenues or limit our operations.

The enforcement of civil liabilities against Rowan plc may be more difficult.

Because Rowan plc is a public limited company incorporated under English law, investors could experience more difficulty enforcing judgments obtained against Rowan plc in U.S. courts than would be the case for U.S. judgments obtained against a U.S. company. In addition, it may be more difficult to bring some types of claims against Rowan plc in courts in the U.K. than it would be to bring similar claims against a U.S. company in a U.S. court.

Our articles of association include mandatory offer provisions that may have the effect of discouraging, delaying or preventing hostile takeovers, including those that might result in a premium being paid over the market price of our shares, and discouraging, delaying or preventing changes in control or management.

Although Rowan plc is not currently subject to the U.K. Takeover Code, certain provisions similar to the mandatory offer provisions and certain other aspects of the U.K. Takeover Code are included in our articles of association. As a result, among other matters, a Rowan plc shareholder, that together with persons acting in concert, acquired 30 percent or more of our issued shares without making an offer to all of our other shareholders that is in cash or accompanied by a cash alternative would be at risk of certain Board sanctions unless they acted with the consent of our Board or the prior approval of the shareholders. The ability of shareholders to retain their shares upon completion of a mandatory offer may depend on whether the offeror subsequently causes us to propose a court-approved scheme of arrangement that would compel minority shareholders to transfer or surrender their shares in favor of the offeror or, if the offeror has acquired at least 90 percent of the relevant shares, the offeror requires minority shareholders to accept the offer under the 'squeeze-out' provisions in our articles of association. The mandatory offer provisions in our articles of association could have the effect of discouraging the acquisition and holding of interests of 30 percent or more of issued shares and encouraging those shareholders who may be acting in concert with respect to the acquisition of shares to seek to obtain the consent of our Board before effecting any additional purchases. In addition, these provisions may adversely affect the market price of our shares or inhibit fluctuations in the market price of our shares that could otherwise result from actual or rumored takeover attempts.

As a result of increased shareholder approval requirements, we may have less flexibility as a U.K. public limited company than as a Delaware corporation with respect to certain aspects of capital management.

Under Delaware law, directors may issue, without further stockholder approval, any shares authorized in a company's certificate of incorporation that are not already issued or reserved. Delaware law also provides substantial flexibility in establishing the terms of preferred shares. However, English law provides that a board of directors may generally only allot shares with the prior authorization of shareholders; such authorization must state the maximum amount of shares that may be allotted and may only be for a maximum period of five years.

English law also generally provides shareholders with preemptive rights when new shares are issued for cash while Delaware law does not. However, it is possible for the articles of association, or shareholders in a general meeting, to exclude preemptive rights for a maximum period of up to five years from the date of adoption of the exclusion.

English law also generally prohibits us from repurchasing our shares on the open market, and prohibits us from repurchasing our shares by way of "off-market purchases" without the prior approval of shareholders by special resolution (i.e., 75 percent of votes cast), which approval lasts for a maximum period of five years.

Prior to the redomestication, resolutions were adopted to authorize the allotment of a certain amount of shares, exclude certain preemptive rights and permit off market purchases, in each case without further shareholder approval, but these authorizations will expire in 2017 unless further approved by our shareholders prior to the expiration date.

We cannot assure you that situations will not arise where U.K. shareholder approval requirements for the extension or expansion of any of these actions would deprive our shareholders of substantial capital management benefits.

English law requires that we meet certain additional financial requirements before we declare dividends and return funds to shareholders.

Under English law, we are only able to declare dividends and make other distributions to our shareholders out of the accumulated distributable reserves on our parent company's statutory balance sheet. Distributable reserves are a company's accumulated, realized profits, so far as not previously utilized by distribution or capitalization, less its accumulated, realized losses (including asset impairments), so far as not previously written off in a reduction or reorganization of capital duly made. The parent's sources of income include service agreements between the parent and certain indirect subsidiaries and the remittance of profit of the parent's direct subsidiary in the form of dividends.

English law also provides that a public company can only make a distribution if, among other things (a) the amount of its net assets (that is, the excess of total assets over liabilities) is not less than the total of its called-up share capital and non-distributable reserves and (b) if, and to the extent that, the distribution does not reduce the amount of its net assets to less than that total.

We may be unable to remit the profits of our subsidiaries in a timely or tax efficient manner. If at any time we do not have sufficient distributable reserves to declare and pay quarterly dividends, Rowan plc may undertake a reduction in its capital, in addition to the reduction in capital taken in 2014, to reduce the amount of our share capital and non-distributable reserves and to create a corresponding increase in our distributable reserves out of which future distributions to shareholders can be made. To comply with English law, a reduction of capital would be subject to (a) approval of shareholders at the annual shareholder meeting by special resolution; (b) confirmation by an order of the

English Courts and (c) the Court order being delivered to and registered by the Registrar of Companies in England. If we were to pursue a reduction of capital as a course of action, and failed to obtain the necessary approvals from shareholders and the English Courts, we may undertake other efforts to allow Rowan plc to declare dividends or make other distributions to shareholders.

ITEM 1B. UNRESOLVED STAFF COMMENTS

The Company has no unresolved SEC staff comments.

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ITEM 2. PROPERTIES

Our primary U.S. offices are located in leased space in Houston, Texas. Additionally, we own or lease other office, maintenance and warehouse facilities in Texas, Scotland, Saudi Arabia, Bahrain, Dubai, Qatar, Trinidad, Norway, Luxembourg, Angola and Malaysia.

Drilling Rigs

Following are the principal drilling equipment owned by us and their location at January 20, 2016. Water and drilling depths are the "rated" depths; actual depths may vary depending on operating location and equipment used:

		Depth (feet)			
Rig Name	Class Name/Type	Water	Drilling	Year in service/ significant refurbishment	Location
Ultra-Deepwater Drillships:					
Rowan Renaissance	Gusto MSC P10,000	12,000	40,000	2014	US GOM
Rowan Resolute	Gusto MSC P10,000	12,000	40,000	2014	US GOM
Rowan Reliance	Gusto MSC P10,000	12,000	40,000	2015	US GOM
Rowan Relentless	Gusto MSC P10,000	12,000	40,000	2015	US GOM
Jack-ups:					
Rowan Norway (1)	N-Class	400	35,000	2011	Norway
Rowan Stavanger (1)	N-Class	400	35,000	2011	U.K. North Sea
Rowan Viking (1)	N-Class	400	35,000	2011	Norway
Rowan EXL IV (1)	EXL	350	40,000	2011	Malaysia
Rowan EXL III (1)	EXL	350	40,000	2011	US GOM
Rowan EXL II (1)	EXL	350	35,000	2011	Trinidad
Rowan EXL I (1)	EXL	350	35,000	2010	Malaysia
Joe Douglas (1)	240C	375	35,000	2012	Trinidad
Ralph Coffman (1)	240C	375	35,000	2009	US GOM
Rowan Mississippi (1)	240C	375	35,000	2008	Saudi Arabia
J.P. Bussell (1)	Tarzan	300	35,000	2008	Bahrain
Hank Boswell (1)	Tarzan	300	35,000	2006	Saudi Arabia
Bob Keller (1)	Tarzan	300	35,000	2005	Saudi Arabia
Scooter Yeargain (1)	Tarzan	300	35,000	2004	Saudi Arabia
Bob Palmer (1)	Super Gorilla XL	490	35,000	2003	Saudi Arabia
Rowan Gorilla VII (1)	Super Gorilla	450	35,000	2002	U.K. North Sea
Rowan Gorilla VI (1)	Super Gorilla	450	35,000	2000	Norway
Rowan Gorilla V (1)	Super Gorilla	400	35,000	1998	U.K. North Sea
Rowan Gorilla IV (1)	Gorilla	450	35,000	1986	US GOM
Rowan Gorilla III (2)(3)	Gorilla	450	30,000	1984	US GOM
Rowan Gorilla II (2)(3)	Gorilla	380	30,000	1984	Malaysia
Rowan California (2)	116C	300	25,000	1983	Qatar
Cecil Provine (2)(3)	116C	300	30,000	1982	US GOM

Gilbert Rowe [2]	116C	300	30,000	1981/2013	Saudi Arabia
Arch Rowan [2]	116C	350	30,000	1981	Saudi Arabia
Charles Rowan [2]	116C	350	30,000	1981	Saudi Arabia
Rowan Middletown [2]	116C	300	30,000	1980	Saudi Arabia

(1) High-specification jack-up, which is defined as having hook-load capacity of at least two million pounds.
(2) Premium jack-up, which is defined as a cantilevered rig capable of operating in water depths of 300 feet or more.
(3) The Cecil Provine, Rowan Gorilla II, and Rowan Gorilla III are currently cold-stacked.

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ITEM 3. LEGAL PROCEEDINGS

We are involved in various routine legal proceedings incidental to our businesses and are vigorously defending our position in all such matters. We believe there are no known contingencies, claims or lawsuits that could have a material adverse effect on our financial position, results of operations or cash flows.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

EXECUTIVE OFFICERS OF THE REGISTRANT

The names, positions and ages of the executive officers of the Company as of February 26, 2016, are listed below. Our executive officers are appointed by the Board of Directors and serve at the discretion of the Board of Directors. There are no family relationships among these officers, nor any arrangements or understandings between any officer and any other person pursuant to which the officer was selected.

Name	Position	Age
W. Matt Ralls	Executive Chairman	66
Thomas P. Burke	President and Chief Executive Officer	48
Stephen M. Butz	Executive Vice President, Chief Financial Officer and Treasurer	44
Mark A. Keller	Executive Vice President, Business Development	63
Melanie M. Trent	Executive Vice President, General Counsel, Chief Administrative Officer and Company Secretary	51
Gregory M. Hatfield	Vice President and Controller	46

Mr. Ralls was appointed Executive Chairman of the Board in April 2014. Prior to that time, Mr. Ralls served as President and Chief Executive Officer and a director since January 2009 until his retirement as Chief Executive Officer in April 2014. Mr. Ralls currently serves as a director of Cabot Oil & Gas Corporation and Superior Energy Services.

Dr. Burke was appointed Chief Executive Officer and elected a director of the Company in April 2014. He served as Chief Operating Officer beginning in July 2011 and was appointed President in March 2013. Dr. Burke first joined the Company in December 2009, serving as Chief Executive Officer and President of LeTourneau Technologies until the sale of LeTourneau in June 2011.

Mr. Butz became Executive Vice President, Chief Financial Officer and Treasurer upon joining the Company in December 2014. Prior to that time, Mr. Butz served as Executive Vice President and Chief Financial Officer at Hercules Offshore, Inc. He was Senior Vice President and Chief Financial Officer from 2010 to 2013 and held a number of other key positions after joining Hercules Offshore in 2005, including Director of Corporate Development and Vice President, Finance and Treasurer.

Since January 2007, Mr. Keller's principal occupation has been Executive Vice President, Business Development. Prior to that time, Mr. Keller served as Senior Vice President, Marketing.

Ms. Trent became Executive Vice President and General Counsel in September 2014. Prior to that time, Ms. Trent served as Senior Vice President, Chief Administrative Officer and Company Secretary since July 2011. From March 2010 to July 2011, she served as Vice President and Corporate Secretary. Ms. Trent has served as Corporate Secretary since she joined the Company in 2005.

Mr. Hatfield has served as Vice President and Controller since March 2010. From May 2005 to March 2010, Mr. Hatfield served as Controller.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON STOCK, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our shares are listed on the NYSE under the symbol "RDC." The following table sets forth the high and low sales prices of our shares for each quarterly period within the two most recent years as reported by the NYSE Consolidated Transaction Reporting System.

	2015		2014	
Quarter	High	Low	High	Low
First	$25.13	$17.23	$35.17	$31.13
Second	24.31	17.56	33.78	29.50
Third	21.14	14.63	32.16	24.96
Fourth	21.83	15.41	25.63	19.50

On January 31, 2016, there were 72 shareholders of record. Many of our shareholders hold their shares in "street name" by a nominee of Depository Trust Company, which is one shareholder of record.

The following table sets forth the per share quarterly cash dividends declared during the two most recent fiscal years.

Quarter	2015	2014
First	$0.10	$—
Second	0.10	0.10
Third	0.10	0.10
Fourth	0.10	0.10

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The graph below presents the relative investment performance of our ordinary shares, the Dow Jones U.S. Oil Equipment & Services Index, and the S&P 500 Index for the five-year period ended December 31, 2015, assuming reinvestment of dividends.

	12/31/2010	12/31/2011	12/31/2012	12/31/2013	12/31/2014	12/31/2015
Rowan	100.00	86.88	89.57	101.29	67.53	50.06
S&P 500 Index	100.00	102.11	118.45	156.82	178.29	180.75
Dow Jones US Oil Equipment & Services Index	100.00	87.57	87.86	112.82	93.39	72.40

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Issuer Purchases of Equity Securities

The following table summarizes acquisitions of our shares for the fourth quarter of 2015:

Month ended	Total number of shares purchased [1]	Average price paid per share [1]	Total number of shares purchased as part of publicly announced plans or programs[2]	Approximate dollar value of shares that may yet be purchased under the plans or programs[2]
Balance forward				$—
October 31, 2015	1,468	$16.25	—	—
November 30, 2015	1,766	$11.85	—	—
December 31, 2015	238	$20.15	—	—
Total	3,472	$14.28	—	

[1] The total number of shares acquired includes shares acquired from employees by an affiliated employee benefit trust upon forfeiture of nonvested awards or in satisfaction of tax withholding requirements and shares purchased, if any, pursuant to a publicly announced share repurchase program. The price paid for shares acquired as a result of forfeitures is the par value of $0.125 per share. The price paid for shares acquired in satisfaction of withholding taxes is the share price on the date of the transaction. There were no shares repurchased under any share repurchase program during the fourth quarter of 2015.
[2] The ability to make share repurchases is subject to the discretion of the Board of Directors and the limitations set forth in the Companies Act, which generally provide that share repurchases may only be made out of distributable reserves. In addition, U.K. law also generally prohibits a company from repurchasing its own shares through "off market purchases" without the prior approval of shareholders, which approval lasts for a maximum period of five years. Prior to and in connection with the redomestication, the Company obtained approval to purchase its own shares. To effect such repurchases, the Company entered into a purchase agreement with a specified dealer in July 2012, pursuant to which the Company may purchase up to a maximum of 50,000,000 shares over a five-year period, subject to an annual cap of 10% of the shares outstanding at the beginning of each applicable year. Subject to Board approval, share repurchases may be commenced or suspended from time to time without prior notice and, in accordance with the shareholder approval and U.K. law, any shares repurchased by the Company will be cancelled. The authority to repurchase shares terminates in April 2017 unless otherwise reapproved by the Company's shareholders prior to that time. U.K. law prohibits the Company from purchasing its shares in the open market because they are not traded on a recognized investment exchange in the U.K.

For information concerning our shares to be issued in connection with equity compensation plans, see Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters," of this Form 10-K.

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ITEM 6. SELECTED FINANCIAL DATA

Selected financial data for each of the last five years is presented below:

	2015	2014	2013	2012	2011
	(Dollars in thousands, except per share amounts)				
Operations					
Revenues	$2,137,018	$1,824,383	$1,579,284	$1,392,607	$939,229
Costs and expenses:					
Direct operating costs (excluding items shown below)	993,087	991,340	860,893	752,173	508,066
Depreciation and amortization	391,418	322,641	271,008	247,900	183,903
Selling, general and administrative	115,779	125,834	131,373	99,712	88,278
Gain on disposals of property and equipment	(7,703)	(1,778)	(20,119)	(2,502)	(1,577)
(Gain) loss on litigation settlement [1]	—	(20,875)	—	(4,700)	6,100
Material charges and other operating expenses [2]	337,347	573,950	4,453	44,972	4,876
Total costs and expenses	1,829,928	1,991,112	1,247,608	1,137,555	789,646
Income (loss) from operations	307,090	(166,729)	331,676	255,052	149,583
Other income (expense) — net	(149,380)	(102,878)	(70,437)	(71,582)	(19,503)
Income (loss) from continuing operations, before income taxes	157,710	(269,607)	261,239	183,470	130,080
Provision (benefit) for income taxes	64,399	(150,732)	8,663	(19,829)	(5,659)
Income (loss) from continuing operations	93,311	(118,875)	252,576	203,299	135,739
Discontinued operations, net of taxes [3]	—	4,023	—	(22,697)	601,102
Net income (loss)	$93,311	$(114,852)	$252,576	$180,602	$736,841
Basic income (loss) per common share:					
Income (loss) from continuing operations	$0.75	$(0.96)	$2.04	$1.65	$1.09
Income (loss) from discontinued operations	—	0.03	—	(0.18)	4.80
Net income (loss)	$0.75	$(0.93)	$2.04	$1.47	$5.89
Diluted income (loss) per common share:					
Income (loss) from continuing operations	$0.75	$(0.96)	$2.03	$1.64	$1.07
Income (loss) from discontinued operations	—	0.03	—	(0.18)	4.76
Net income (loss)	$0.75	$(0.93)	$2.03	$1.46	$5.83
Financial Position					
Cash and cash equivalents	$484,228	$339,154	$1,092,844	$1,024,008	$438,853
Property, plant and equipment — net	$7,405,832	$7,432,212	$6,385,755	$6,071,729	$5,678,713
Total assets	$8,347,267	$8,392,350	$7,975,761	$7,699,487	$6,597,845
Long-term debt, less current portion	$2,692,419	$2,788,482	$2,008,700	$2,009,598	$1,089,335
Shareholders' equity	$4,772,459	$4,691,399	$4,893,761	$4,531,724	$4,325,987
Statistical Information					
Current ratio [4]	2.80	2.82	4.50	5.61	2.46
Debt to capitalization ratio	36%	37%	29%	31%	20%
Book value per share of common stock outstanding	$38.24	$37.66	$39.39	$36.48	$35.01
Price range of common stock:					
High	$25.13	$35.17	$38.65	$39.40	$44.83
Low	$14.63	$19.50	$30.21	$28.62	$28.13
Cash dividends declared per share	$0.40	$0.30	$—	$—	$—

(1) (Gain) loss on litigation settlement includes: 2014 – a gain of $20.9 million in cash received for damages incurred as a result of a tanker's collision with the Rowan EXL I in 2012; 2012 – a $4.7 million gain for cash received in connection with the settlement of a 2005 dispute with a customer; 2011 – a $6.1 million payment to settle a lawsuit in connection with the Company's obligation under a charter agreement for the Rowan Halifax.

(2) Material charges and other operating expenses consisted of the following: 2015 – $329.8 million of non-cash asset impairment charges and $7.6 million of costs to terminate a rig refurbishment contract; 2014 – $574.0 million of non-cash asset impairment charges; 2013 – $4.5 million of non-cash asset impairment charges; 2012 – $13.8 million of legal and consulting fees incurred in connection with the Company's redomestication, $12.0 million of repair costs for the Rowan EXL I following its collision with a tanker, $8.7 million of pension settlement costs in connection with lump sum pension payments to employees of the Company's former manufacturing subsidiary, $8.1 million of non-cash asset impairment charges, and $2.3 million of incremental non-cash share-based compensation cost in connection with the retirement of an employee; and 2011 – $4.9 million of incremental non-cash and cash compensation cost in connection with the separation of an employee.

(3) In 2011, the Company sold its manufacturing and land drilling operations, which are classified as discontinued operations. In 2014, we sold a land rig retained from the sale and recognized a $4.0 million gain, net of tax.

(4) Current ratio excludes assets and liabilities of discontinued operations.

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

OUR BUSINESS

Rowan plc is a global provider of offshore contract drilling services to the international oil and gas industry, with a focus on high-specification and premium jack-up rigs and ultra-deepwater drillships. Our fleet currently consists of 31 mobile offshore drilling units, including 27 self-elevating jack-up rigs and four ultra-deepwater drillships. Our fleet operates worldwide, including the United States Gulf of Mexico, the United Kingdom and Norwegian sectors of the North Sea, the Middle East and Trinidad. In 2015, we completed our ultra-deepwater drillship construction program with the following four new drillships:

- the Rowan Renaissance, which commenced drilling operations offshore West Africa in April 2014 and is now operating in the US GOM;
- the Rowan Resolute, which commenced operations in the US GOM in October 2014;
- the Rowan Reliance, which commenced operations in the US GOM in February 2015; and
- the Rowan Relentless, which commenced operations in the US GOM in June 2015.

In addition to our ultra-deepwater drillships in the US GOM, as of January 20, 2016, the date of our most recent Fleet Status Report, we had five jack-ups under contract in the North Sea, ten under contract in the Middle East, one under contract in the US GOM, and two under contract in Trinidad. We had an additional six marketed jack-up rigs without contracts and three cold-stacked.

We contract our drilling rigs, related equipment and work crews primarily on a "day rate" basis. Under day rate contracts, we generally receive a fixed amount per day for each day we are performing drilling or related services. In addition, our customers may pay all or a portion of the cost of moving our equipment and personnel to and from the well site. Contracts generally range in duration from one month to multiple years.

In 2015, we sold our three oldest jack-up rigs – the Rowan Juneau, Rowan Alaska and Rowan Louisiana. The Rowan Juneau and Rowan Alaska, which had not worked in several years, were sold under agreements that prohibit their future use as drilling units.

CURRENT BUSINESS ENVIRONMENT

The business environment for offshore drillers continues to be challenging as commodity prices remain low, demand for drilling services has declined, and the supply of offshore drilling rigs significantly outweighs demand. Beginning in June 2014, the price of crude oil, a key factor in determining our customer activity levels, rapidly declined to levels that have failed to stimulate meaningful incremental contracting activity through the duration of 2015 and into 2016. Operators worldwide reduced capital expenditure budgets for 2015 with further reductions announced for 2016. As a result, operators have cut operating costs and postponed drilling programs, resulting in reduced demand for offshore drilling services, downward pressure on day rates and rig utilization, and the cold-stacking and retirement of rigs in the worldwide fleet. In response to jack-up market conditions, during 2015 we reduced day rates on certain drilling contracts, some of which were in exchange for extended contract duration; experienced significant idle time on several units; retired two of our oldest jack-ups (which were then sold in the third quarter of 2015 for use other than for drilling operations); sold another older jack-up in the fourth quarter of 2015, and cold-stacked three additional jack-ups. Given the current outlook, we will likely enter into contracts for certain of our drilling rigs at substantially lower day rates; we are likely to have difficulty securing new drilling contracts; we have and will continue to experience extended periods of idle time for other drilling rigs and difficulty in securing suitable contracts for reactivating our currently stacked rigs; or we may stack or retire additional units. Additionally, customers may continue to seek to renegotiate or terminate existing contracts.

A significant contributing factor to the softness in the offshore drilling market has been the influx of 214 newbuild jack-ups and 155 newbuild floaters delivered since early 2006, the beginning of the current newbuild cycle. The addition of newbuild units, combined with numerous rigs having rolled off contracts in past months, has continued to increase competition, putting additional downward pressure on day rates and utilization. Further, as of February 2, 2016, there were approximately 125 jack-up rigs under construction worldwide for delivery through 2020 (38% of the currently utilized jack-up fleet of approximately 328 rigs), approximately 51 of which are considered high-specification (74% of the delivered high-specification fleet). Currently, there are approximately 82 competitive newbuild jack-up rigs scheduled for delivery during 2016, and only seven have contracts. For the floater market there are approximately 70 floaters under construction worldwide for delivery through 2020 (37% of the currently utilized floater fleet of approximately 188 rigs). Following the negotiated delivery delays on several units into future years, there are approximately 22 competitive newbuild floaters scheduled for delivery during 2016, and nine having contracts.

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We expect that the business environment for 2016 will remain challenging and, in the absence of a recovery in commodity prices, will likely deteriorate further. However, we believe Rowan is well-positioned strategically given our status as a strong and stable financial counterparty to our customers, current backlog of $3.6 billion as of January 20, 2016, solid operational reputation, and a modern fleet of high-specification jack-ups and state-of-the-art ultra-deepwater drillships. While challenging market conditions persist, we continue to focus on operating efficiencies and cost control, which could include cold-stacking or retiring additional drilling rigs.

RESULTS OF OPERATIONS

The following table presents certain key performance indicators by rig classification:

	2015	2014	2013
Revenues (in thousands):			
Deepwater	$730,813	$170,502	$—
Jack-ups	1,361,320	1,598,769	1,542,819
Subtotal - Day rate revenues	2,092,133	1,769,271	1,542,819
Other revenues[1]	44,885	55,113	36,465
Total revenues	$2,137,018	$1,824,384	$1,579,284
Revenue-producing days:			
Deepwater	1,178	262	—
Jack-ups	7,852	9,019	9,027
Total revenue-producing days	9,030	9,281	9,027
Average day rate: [2]			
Deepwater	$620,546	$650,356	$—
Jack-ups	$173,376	$177,266	$170,919
Total fleet	$231,699	$190,629	$170,919
Utilization: [3]			
Deepwater	93 %	80 %	— %
Jack-ups	74 %	82 %	81 %
Total fleet	76 %	82 %	81 %

(1) Other revenues, which are primarily revenues received for contract reimbursable costs, are excluded from the computation of average day rate.
(2) Average day rate is computed by dividing day rate revenues by the number of revenue-producing days, including fractional days. Day rate revenues include the contractual rates and amounts received in lump sum, such as for rig mobilization or capital improvements, which are amortized over the initial term of the contract. Revenues attributable to reimbursable expenses are excluded from average day rates.
(3) Utilization is the number of revenue-producing days, including fractional days, divided by the aggregate number of calendar days in the period, or, with respect to new rigs entering service, the number of calendar days in the period from the date the rig was placed in service.

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A summary of our consolidated results of operations follows (in thousands):

	2015	2014	2013
Revenues	$2,137,018	$1,824,383	$1,579,284
Direct operating costs (excluding items below)	993,087	991,340	860,893
Depreciation and amortization	391,418	322,641	271,008
Selling, general and administrative	115,779	125,834	131,373
Other operating items	329,644	551,297	(15,666)
Operating income (loss)	307,090	(166,729)	331,676
Other income (expense), net	(149,380)	(102,878)	(70,437)
Provision (benefit) for income taxes	64,399	(150,732)	8,663
Net income (loss) from continuing operations	93,311	(118,875)	252,576
Discontinued operations, net of tax	—	4,023	—
Net income (loss)	$93,311	$(114,852)	$252,576

Revenues

Revenues for 2015 increased by 17% to $2.137 billion from $1.824 billion in 2014, compared to $1.579 billion in 2013. The higher revenues for 2015 were primarily due to the addition of the deepwater drillships – the Rowan Reliance and Rowan Relentless in 2015 and the full-year effect of the Rowan Renaissance and Rowan Resolute, which commenced operations in 2014.

An analysis of the net changes in revenues for 2015 compared to 2014 and for 2014 compared to 2013 are set forth below (in millions):

	Increase (decrease)
2015 Compared to 2014:	
Addition of the Rowan Reliance and Rowan Relentless in 2015	$290.4
Addition of the Rowan Renaissance and Rowan Resolute in 2014	269.9
Lower jack-up utilization	(206.9)
Lower average day rates for existing rigs	(30.6)
Revenues for reimbursable costs and other, net	(10.2)
Net increase	$312.6
2014 Compared to 2013:	
Addition of the Rowan Renaissance and Rowan Resolute	$170.5
Higher average day rates for existing rigs	57.3
Revenues for reimbursable costs and other, net	17.3
Net increase	$245.1

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Direct operating costs

Changes in direct operating costs for 2015 compared to 2014 and for 2014 compared to 2013 follow (in millions):

	Increase (decrease)
2015 Compared to 2014:	
Addition of the Rowan Reliance and Rowan Relentless in 2015	$76.4
Addition of the Rowan Renaissance and Rowan Resolute in 2014	68.4
Return to work of the Rowan Gorilla III, Rowan Gorilla VI and the Rowan Viking	32.2
Decrease due to idle, sold or cold-stacked rigs	(75.8)
Reduction of regional shorebases	(13.5)
Reimbursable costs	(10.1)
Other, net - primarily repair and maintenance and personnel costs for other rigs	(75.9)
Net increase	$1.7
2014 Compared to 2013:	
Addition of the Rowan Renaissance and Rowan Resolute	$62.0
Higher costs due to rigs in shipyards in prior year, net	29.7
Expansion of regional shorebases	15.8
Reimbursable costs	17.6
Other, net	5.3
Net increase	$130.4

Depreciation and amortization

Increases in depreciation of 21% and 19% in 2015 and 2014, respectively, compared to the prior years, were primarily due to the addition of the four drillships.

Selling, general and administrative

Selling, general and administrative expenses for 2015 decreased by $10.1 million or 8% compared to 2014, primarily due to cost-reduction measures, which included reductions in headcount and fewer professional services.

Selling, general and administrative expenses for 2014 decreased by $5.5 million or 4% compared to 2013, primarily due to fewer professional services and fees for corporate restructuring; initiatives related to the Company's internationalization and entry into the ultra-deepwater market; and to lower equity compensation expense resulting from fair market adjustments to certain share-based awards recorded under the liability method of accounting.

Other operating items

As a result of the extended downturn in the market for offshore contract drilling services, we conducted an impairment test of our assets in 2015 and determined that the carrying values for ten of our jack-up rigs were not recoverable from their undiscounted expected future cash flows and exceeded their fair values. As a result, we recognized an aggregate non-cash asset impairment charge in 2015 in the amount of $329.8 million. In 2014, we recognized non-cash asset impairment charges totaling $565.7 million on twelve jack-up rigs and a charge of $8.3 million for impairment of a Company aircraft, which we sold later in 2014 at an immaterial loss. In 2013, we recognized a $4.5 million non-cash asset impairment charge on a dock and maintenance facility.

In 2015, we sold the Rowan Louisiana, Rowan Alaska and Rowan Juneau jack-up drilling rigs in separate sales and recognized a net gain totaling $8.8 million on proceeds of $15.9 million. In 2013, we sold the Rowan Paris for approximately $40.0 million in cash and recognized a gain on sale of $19.1 million.

In 2015, we recognized a $7.6 million charge for the termination of a contract in connection with refurbishment work on the Rowan Gorilla III.

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In 2014, the Company settled its litigation with the owners and operators of a tanker that collided with the Rowan EXL I in 2012 and received $20.9 million in cash as compensation for damages incurred in 2012 for repair costs to and loss of use of the rig. We recognized the cash receipt in 2014 as a component of operating income.

Provision (benefit) for income taxes

In 2015, we recognized an income tax provision of $64.4 million on pretax income of $157.7 million. The 2015 tax provision was primarily due to the establishment of a valuation allowance on the U.S. deferred tax assets, impairments of assets in foreign jurisdictions with no tax benefits, and an increase in income in high-tax jurisdictions, offset by additional tax benefit for the U.S.-impaired assets and an increase in income in low-tax jurisdictions. Excluding the impact of those items included in material charges and other operating expenses and changes to the valuation allowance, our effective tax rate was 10.9% for 2015.

In 2014, we recognized an income tax benefit of $150.7 million on a $269.6 million pretax loss from continuing operations. The benefit was primarily due to the acceleration of previously deferred intercompany gains and losses associated with impaired assets, the amortization of deferred intercompany gains and losses related to outbounding certain U.S.-owned rigs to our non-U.S. subsidiaries in prior years, and the settlement agreement reached with the U.S. Internal Revenue Service in September 2014.

In 2013, we recognized income tax expense of $8.7 million on $261.2 million of pretax income from continuing operations. The low effective tax rate of 3.3% was due in part to the amortization of deferred intercompany gains and losses related to outbounding certain U.S.-owned rigs to our non-U.S. subsidiaries in prior years; a significant proportion of income earned in low-tax foreign jurisdictions; the implementation of our international restructuring plan, which resulted in the utilization of non-U.S. subsidiaries' foreign taxes paid as credits against U.S. taxable income; additional tax basis in fixed assets due to the application of a ruling in a third-party tax case to the Company's situation; and the continued recognition of tax benefits related to the application of certain tax planning strategies implemented in 2012 related to interest capitalization.

Discontinued operations, net of tax

In 2014, we sold a land rig that was retained in connection with the 2011 sale of the Company's manufacturing operations and recognized a gain on sale of $4.0 million, net of tax effects.

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Results of Operations by Operating Segment

An analysis of our operating income (loss) by operating segment follows (in thousands):

	Deepwater	Jack-ups	Segment total	Unallocated costs and other	Consolidated
2015:					
Revenues	$747,792	$1,389,226	$2,137,018	$—	$2,137,018
Operating expenses:					
Direct operating costs (excluding items below)	276,542	716,545	993,087	—	993,087
Depreciation and amortization	94,613	283,905	378,518	12,900	391,418
Selling, general and administrative	—	—	—	115,779	115,779
Other operating items	—	328,818	328,818	826	329,644
Income (loss) from operations	$376,637	$59,958	$436,595	$(129,505)	$307,090
2014:					
Revenues	$179,834	$1,644,549	$1,824,383	$—	$1,824,383
Operating expenses:					
Direct operating costs (excluding items below)	87,778	903,562	991,340	—	991,340
Depreciation and amortization	24,410	283,542	307,952	14,689	322,641
Selling, general and administrative	—	—	—	125,834	125,834
Other operating items	—	544,775	544,775	6,522	551,297
Income (loss) from operations	$67,646	$(87,330)	$(19,684)	$(147,045)	$(166,729)
2013:					
Revenues	$—	$1,579,284	$1,579,284	$—	$1,579,284
Operating expenses:					
Direct operating costs (excluding items below)	—	860,893	860,893	—	860,893
Depreciation and amortization	—	261,283	261,283	9,725	271,008
Selling, general and administrative	—	—	—	131,373	131,373
Other operating items	—	(14,624)	(14,624)	(1,042)	(15,666)
Income (loss) from operations	$—	$471,732	$471,732	$(140,056)	$331,676

Deepwater – Revenues from deepwater increased by 316% over 2014 due to the startup of drillship operations in 2014 and 2015. Two drillships commenced operations in 2014 and two in 2015. Direct operating costs (exclusive of depreciation and other operating items) as a percentage of revenues declined to 37% of revenues in 2015 from 49% of revenues in 2014 primarily as a result of improved utilization in 2015.

Jack-ups – Revenues from jack-up operations decreased by 16% from 2014 levels due to lower utilization and average day rates in 2015. Direct operating costs (exclusive of depreciation and other operating items) as a percentage of revenues declined to 52% of revenues in 2015 from 55% of revenues in 2014 primarily as a result of cost-reduction measures implemented in 2014 and 2015 and lower out-of-service time in 2015. Other operating items (which includes impairments, gains and losses on equipment sales and other) declined to $328.8 million in 2015 from $544.8 million in 2014. In 2015, we recognized jack-up impairments totaling $330 million versus $566 million recognized in 2014. Other operating items in 2014 also included a $20.9 million gain due to the settlement of litigation for damages to the Rowan EXL I in a 2012 collision with a tanker.

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Jack-up revenue increased by 4% from 2013 to 2014 due to higher average dayrates in 2014 compared to 2013. Direct operating costs (exclusive of depreciation and other operating items) as a percentage of revenues was unchanged at 55% in 2014 compared to 2013. Other operating income for 2013 included a $19.1 million gain on the sale of the Rowan Paris and a $4.5 million non-cash impairment charge on a dock and maintenance facility.

Rig Utilization

The following table sets forth an analysis of time that our rigs were idle or otherwise off-rate as a percentage of in-service time:

	2015	2014	2013
Deepwater:			
Idle	0.0%	0.0%	NA
Out-of-service	0.0%	15.1%	NA
Operational downtime	6.7%	6.3%	NA
Jack-up:			
Idle	12.2%	1.3%	0.6%
Out-of-service	3.0%	8.8%	9.5%
Operational downtime	1.2%	1.0%	1.1%

Idle Days – We define idle days as the time a rig is not under contract and available to work. Idle days exclude cold-stacked rigs, which are not marketed.

Out-of-Service Days – We define out-of-service days as those days when a rig is (or planned to be) out of service and is not able to earn revenue. The Company may be compensated for certain out-of-service days, such as for shipyard stays or for rig transit periods preceding a contract; however, recognition of any such compensation is deferred and recognized over the primary term of the drilling contract.

Out-of-service time for our deepwater fleet for 2014 included 27 days attributable to the Rowan Resolute (35% of in-service time) for commissioning.

Operational Downtime – We define operational downtime as the unbillable time when a rig is under contract and unable to conduct planned operations due to equipment breakdowns or procedural failures.

LIQUIDITY AND CAPITAL RESOURCES

Key balance sheet amounts and ratios at December 31 were as follows (dollars in millions):

	2015	2014
Cash and cash equivalents	$484.2	$339.2
Current assets	$921.3	$938.9
Current liabilities	$328.7	$333.2
Current ratio	2.80	2.82
Long-term debt	$2,692.4	$2,788.5
Shareholders' equity	$4,772.5	$4,691.4
Debt to capitalization ratio	36 %	37 %

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Sources and uses of cash and cash equivalents were as follows (in millions):

	2015	2014	2013
Net operating cash flows	$997.0	$423.0	$623.2
Borrowings, net of issue costs	220.0	792.7	—
Payment of cash dividends	(50.5)	(37.7)	—
Capital expenditures	(722.9)	(1,958.2)	(607.3)
Debt reductions	(317.9)	—	—
Proceeds from asset disposals	19.4	22.0	44.5
Proceeds from equity compensation plans	—	4.7	2.9
All other, net	—	(0.1)	5.5
Total net source (use)	$145.1	$(753.6)	$68.8

Operating Cash Flows

Cash flows from operations increased to approximately $997 million in 2015 from $423 million in 2014. Operating cash flows for 2015 compared to 2014 were positively impacted by the startup of the drillships in 2014 and 2015 and favorable changes in working capital, including lower pension contributions in 2015. Operating cash flows for 2014 compared to 2013 were negatively impacted by an increase in trade and other receivables, receipt of an approximately $53 million U.S. federal income tax refund in 2013, and higher pension contributions in 2014.

The Company has not provided deferred income taxes on undistributed earnings of its non-U.K. subsidiaries, including RCI's non-U.S. subsidiaries. It is the Company’s policy and intention to permanently reinvest earnings of non-U.S. subsidiaries of RCI outside the U.S. Generally, earnings of non-U.K. subsidiaries in which RCI does not have a direct or indirect ownership interest can be distributed to the Company without imposition of either U.K. or local country tax.

As of December 31, 2015, RCI's portion of the unremitted earnings of its non-U.S. subsidiaries that could be includable in taxable income of RCI, if distributed, was approximately $336.8 million. Should the non-U.S. subsidiaries of RCI make a distribution from these earnings, we may be subject to additional U.S. income taxes. It is not practicable to estimate the amount of deferred tax liability related to the undistributed earnings, and RCI's non-U.S. subsidiaries have no plan to distribute earnings in a manner that would cause them to be subject to U.S., U.K. or other local country taxation.

At December 31, 2015, RCI’s non-U.S. subsidiaries held approximately $175 million of the $484 million of consolidated cash and cash equivalents. Management believes the Company has significant net assets, liquidity, contract backlog and/or other financial resources available to meet its operational and capital investment requirements and otherwise allow us to continue to maintain its policy of reinvesting such undistributed earnings outside the U.K. and U.S. indefinitely.

Backlog

Our backlog by geographic area as of the date of our most recent Fleet Status Report is presented below (in thousands):

	January 20, 2016		
	Jack-ups	Deepwater	Total
US GOM	$22,738	$1,426,730	$1,449,468
Middle East	1,391,368	—	1,391,368
North Sea	576,264	—	576,264

Trinidad	151,082	—	151,082
Total backlog	$2,141,452	$1,426,730	$3,568,182

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We estimate our backlog will be realized as follows (in thousands):

	January 20, 2016		
	Jack-ups	Deepwater	Total
2016	$894,683	$844,372	$1,739,055
2017	590,981	564,298	1,155,279
2018	306,730	18,060	324,790
2019	64,970	—	64,970
2020 and later years	284,088	—	284,088
Total backlog	$2,141,452	$1,426,730	$3,568,182

Our contract backlog represents remaining contractual terms and may not reflect actual revenue due to a number of factors such as rig downtime, estimated contract durations and possible customer concessions.

About 67% of our remaining available rig days in 2016 and 43% of available rig days in 2017 were under contract or commitment as of January 20, 2016, excluding cold-stacked rigs. As of that date, we had three jack-ups that were cold-stacked and six that were available.

Investing Activities

With the delivery of our fourth and final drillship in March 2015, we concluded our ultra-deepwater drillship construction program. We took delivery of the first three drillships in 2014.

Capital expenditures in 2015 totaled $722.9 million and included the following:

- $541.3 million for construction of the Rowan Reliance and Rowan Relentless, including costs for mobilization, commissioning, riser gas-handling equipment, software certifications and spares.
- $132.5 million for improvements to the existing fleet, including contractually required modifications; and
- $49.1 million for rig equipment inventory and other.

We currently estimate our 2016 capital expenditures to range from approximately $180-$190 million, primarily for fleet maintenance, rig equipment, spares and other. This amount excludes any contractual modifications that may arise due to our securing additional work.

We expect to fund our 2016 capital expenditures using available cash and cash flows from operations.

The capital budget reflects an appropriation of money that we may or may not spend, and the timing of such expenditures may change. We will periodically review and adjust the capital budget as necessary based upon current and forecast cash flows and liquidity, anticipated market conditions in our business, the availability of financial resources, and alternative uses of capital to enhance shareholder value.

Capital expenditures for 2014 totaled $2.0 billion and included $1.6 billion towards drillship construction; $345 million for improvements to the existing fleet, including contractually required modifications; and $53 million for rig equipment, spares and other.

Capital expenditures for 2013 totaled $607 million and included $229 million towards drillship construction; $323 million for improvements to the existing fleet, including contractually required modifications; and $55 million for rig equipment, spares and other.

Financing Activities

In January 2014, we completed the issuance and sale in a public offering of $400 million aggregate principal amount of 4.75% Senior Notes due 2024, and $400 million aggregate principal amount of 5.85% Senior Notes due 2044. Net proceeds of the offering were approximately $792 million, which the Company used for its drillship construction program and for general corporate purposes.

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In May 2015, the Company amended and restated its revolving credit agreement to increase the borrowing capacity under the facility from $1 billion to $1.5 billion and to extend the maturity date by one year to January 2020. In January 2016, the Company further amended the revolving credit agreement to extend the maturity date by one year to January 2021. Availability under the facility is $1.5 billion through January 23, 2019, declining to $1.44 billion through January 23, 2020, and to approximately $1.29 billion through the maturity in 2021. There were no amounts drawn under the revolving credit facility at December 31, 2015.

During 2015, we paid $101.1 million in cash to retire $97.9 million aggregate principal amount of the 5% Notes due 2017 and 7.875% Notes due 2019, plus accrued interest, and recognized a $1.5 million loss on early extinguishment of debt.

As of December 31, 2015, we had $2.7 billion of outstanding long-term debt consisting of $366.6 million principal amount of 5% Senior Notes due 2017; $435.5 million principal amount of 7.875% Senior Notes due 2019; $700 million principal amount of 4.875% Senior Notes due 2022; $400 million aggregate principal amount of 4.75% Senior Notes due 2024; $400 million principal amount of 5.4% Senior Notes due 2042; and $400 million aggregate principal amount of 5.85% Senior Notes due 2044 (together, the “Senior Notes”). The Senior Notes are fully and unconditionally guaranteed on a senior and unsecured basis by Rowan plc (see Note 15 of Notes to Financial Statements in Item 8 of this Form 10-K).

Annual interest payments on the Senior Notes are estimated to be $153 million in 2016. No principal payments are required until each series’ final maturity date. Management believes that cash flows from operating activities, existing cash balances, and amounts available under the revolving credit facility will be sufficient to satisfy the Company’s cash requirements for the following twelve months.

Restrictive provisions in the Company’s bank credit facility agreement limit consolidated debt to 60% of book capitalization. Our consolidated debt to total capitalization ratio at December 31, 2015, was 36%.

Other provisions of our debt agreements limit the ability of the Company to create liens that secure debt, engage in sale and leaseback transactions, merge or consolidate with another company and, in the event of noncompliance, restrict investment activities and asset purchases and sales, among other things. The Company was in compliance with its debt covenants at December 31, 2015, and expects to remain in compliance throughout 2016.

Cash Dividends

Prior to 2014, the Company had not paid a quarterly cash dividend since 2008. Cash dividends over the last two years are set forth below:

	Cash dividend per share	Declaration date	Record date	Payment date
2014:				
Second quarter	$0.10	4/25/2014	5/5/2014	5/20/2014
Third quarter	0.10	7/31/2014	8/11/2014	8/26/2014
Fourth quarter	0.10	10/30/2014	11/11/2014	11/25/2014
2015:				
First quarter	$0.10	1/29/2015	2/9/2015	3/3/2015
Second quarter	0.10	5/1/2015	5/12/2015	5/26/2015
Third quarter	0.10	7/31/2015	8/11/2015	8/25/2015
Fourth quarter	0.10	10/29/2015	11/9/2015	11/23/2015

In January 2016, the Company announced that it had discontinued its quarterly dividend.

Off-balance Sheet Arrangements and Contractual Obligations

The Company had no off-balance sheet arrangements as of December 31, 2015 or 2014, other than operating lease obligations and other commitments in the ordinary course of business.

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The following is a summary of our contractual obligations at December 31, 2015, including obligations recognized on our balance sheet and those not required to be recognized (in millions):

	Payments due by period				
	Total	Within 1 year	2 to 3 years	4 to 5 years	After 5 years
Long-term debt principal payment	$2,702	$—	$367	$435	$1,900
Interest	1,833	153	287	234	1,159
Purchase obligations	106	106	—	—	—
Operating leases	40	7	11	10	12
Total	$4,681	$266	$665	$679	$3,071

As of December 31, 2015, our liability for unrecognized tax benefits related to uncertain tax positions totaled $75.8 million, inclusive of interest and penalties. Due to the high degree of uncertainty related to these tax matters, we are unable to make a reasonably reliable estimate as to the timing of cash settlement with the respective taxing authorities, and we have therefore excluded this amount from the contractual obligations presented in the table above.

We periodically employ letters of credit or other bank-issued guarantees in the normal course of our businesses, and had outstanding letters of credit of approximately $4.2 million at December 31, 2015.

Pension Obligations

Minimum contributions under defined benefit pension plans are determined based upon actuarial calculations of pension assets and liabilities that involve, among other things, assumptions about long-term asset returns and interest rates. Similar calculations were used to estimate pension costs and obligations as reflected in our consolidated financial statements (see “Critical Accounting Policies and Management Estimates – Pension and other postretirement benefits”). As of December 31, 2015, our financial statements reflected an aggregate unfunded pension liability of $209 million. We expect to make minimum contributions to our defined benefit pension plans of approximately $22 million in 2016, and we will continue to make significant pension contributions over the next several years. Additional funding may be required if, for example, future interest rates or pension asset values decline or there are changes in legislation.

Contingent Liabilities

We are involved in various legal proceedings incidental to our businesses and are vigorously defending our position in all such matters. The Company believes that there are no known contingencies, claims or lawsuits that could have a material effect on its financial position, results of operations or cash flows.

CRITICAL ACCOUNTING POLICIES AND MANAGEMENT ESTIMATES

Our significant accounting policies are presented in Note 2 of “Notes to Consolidated Financial Statements” in Item 8 of this Form 10-K. These policies and management judgments, assumptions and estimates made in their application underlie reported amounts of assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. We believe that our most critical accounting policies and management estimates involve carrying values of long-lived assets, pension and other postretirement benefit liabilities and costs (specifically assumptions used in actuarial calculations), and income taxes (particularly our estimated reserves for uncertain tax positions), as changes in such policies and/or estimates would produce significantly different amounts from those reported herein.

Depreciation and impairments of long-lived assets

We depreciate our assets using the straight-line method over their estimated useful service lives after allowing for salvage values. We estimate useful lives and salvage values by applying judgments and assumptions that reflect both historical experience and expectations regarding future operations, utilization and performance. Useful lives may be affected by a variety of factors including technological advances in methods of oil and gas exploration, changes in market or economic conditions, and changes in laws or regulations that affect the drilling industry. Applying different judgments and assumptions in establishing useful lives and salvage values may result in values that differ from recorded amounts. In connection with the completion of an asset impairment test in 2014, we reevaluated our policy with respect to salvage values and, in light of our historical experience, we reduced salvage values for our jack-up rigs from 20 percent to 10 percent of historical cost.

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We evaluate the carrying value of our property and equipment, primarily our drilling rigs, whenever events or changes in circumstances indicate that their carrying values may not be recoverable. Potential impairment indicators include rapid declines in commodity prices, stock prices, rig utilization and day rates, among others. The offshore drilling industry has historically been highly cyclical and it is not unusual for rigs to be underutilized or idle for extended periods of time and subsequently resume full or near full utilization when business cycles improve. Similarly, during periods of excess supply, rigs may be contracted at or near cash break-even rates for extended periods. Impairment situations may arise with respect to specific rigs, specific categories or classes of rigs, or rigs in a certain geographic region. Our rigs are mobile and may generally be moved from regions with excess supply, if economically feasible.

Asset impairment evaluations are, by nature, highly subjective. In most instances, they involve expectations of future cash flows to be generated by our drilling rigs and are based on management's judgments and assumptions regarding future industry conditions and operations, as well as management's estimates of future expected utilization, contract rates, expense levels and capital requirements. The estimates, judgments, and assumptions used by management in the application of our asset impairment policies reflect both historical experience and an assessment of current operational, industry, market, economic and political environments. The use of different estimates, judgments, assumptions (including discount rates) and expectations regarding future industry conditions and operations would likely result in materially different asset carrying values and operating results.

In 2014 and 2015, we conducted impairment tests of our assets and determined that the carrying values of certain jack-up rigs were not recoverable from their undiscounted cash flows and exceeded their fair values. As a result, we recognized non-cash asset impairment charges of approximately $566 million in 2014 and $330 million in 2015. (See Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.)

Pension and other postretirement benefits

Our pension and other postretirement benefit liabilities and costs are based upon actuarial computations that reflect our assumptions about future events, including long-term asset returns, interest rates, annual compensation increases, mortality rates and other factors. Key assumptions at December 31, 2015, included weighted average discount rates of 4.54% and 3.97% used to determine pension benefit obligations and net cost, respectively, an expected long-term rate of return on pension plan assets of 7.30% and annual healthcare cost increases ranging from 6.7% in 2016 to 4.5% in 2026 and beyond. The assumed discount rate is based upon the average yield for Moody’s Aa-rated corporate bonds, and the rate of return assumption reflects a probability distribution of expected long-term returns that is weighted based upon plan asset allocations. A one-percentage-point decrease in the assumed discount rate would increase our recorded pension and other postretirement benefit liabilities by approximately $94.0 million, while a one-percentage-point decrease (increase) in the expected long-term rate of return on plan assets would increase (decrease) annual net benefits cost by approximately $5.6 million. A one-percentage-point increase in the assumed healthcare cost trend rate would increase 2016 other postretirement benefit cost by $0.3 million. To develop the expected long-term rate of return on assets assumption, we considered the current level of expected returns on risk-free investments (primarily government bonds), the historical level of the risk premium associated with the plans’ other asset classes, and the expectations for future returns of each asset class. The expected return for each asset class was then weighted based upon the current asset allocation to develop the expected long-term rate of return on assets assumption for the plan, which was reduced to 7.30% at December 31, 2015, from 7.45% at December 31, 2014.

Income taxes

In accordance with accounting guidelines for income tax uncertainties, we evaluate each tax position to determine if it is more likely than not that the tax position will be sustained upon examination, based on its merits. A tax position that meets the more-likely-than-not recognition threshold is subject to a measurement assessment to determine the amount of benefit to recognize in income for the period, and a reserve, if any. Our income tax returns are subject to audit by U.S. federal, state, and foreign tax authorities. Determinations by such taxing authorities that differ materially from our recorded estimates, either favorably or unfavorably, may have a material impact on our results of operations, financial position and cash flows. We believe our reserve for uncertain tax positions totaling $65 million at December 31, 2015, is properly recorded in accordance with the accounting guidelines.

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers, which sets forth a global standard for revenue recognition and replaces most existing industry-specific guidance. We will be required to adopt the new standard in annual and interim periods beginning January 1, 2018. The amendments may be applied retrospectively to each prior period presented or retrospectively with the cumulative effect recognized as of the date of initial application. We are evaluating the standard and have not yet determined our implementation method upon adoption or what impact adoption will have on our financial statements.

In February 2015, the FASB issued ASU No. 2015-02, Amendments to the Consolidation Analysis, which changes the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. We will be required to adopt the new standard in annual and interim periods beginning January 1, 2016. We do not expect adoption of the new standard will have a material effect on our financial statements.

In April 2015, the FASB issued ASU No. 2015-03, Simplifying the Presentation of Debt Issuance Costs, which changes the presentation of debt issuance costs in financial statements. Under this ASU, an entity presents such costs in the balance sheet as a direct deduction from the related debt liability rather than as an asset. We adopted the new standard effective December 31, 2015. As a result of adoption, we reclassified unamortized debt issue costs in the amount of $16.4 million and $18.8 million as of December 31, 2015 and 2014, respectively, and reduced the carrying value of long-term debt by the same amounts.

In November 2015, the FASB issued ASU No. 2015-17, Balance Sheet Classification of Deferred Taxes, which requires entities to present deferred tax assets and deferred tax liabilities in balance sheets as noncurrent. We will be required to adopt the new standard in annual and interim periods beginning January 1, 2017, with early adoption permitted. The amendments in this ASU may be applied either prospectively to all deferred tax liabilities and assets or retrospectively to all periods presented. We are evaluating the standard and have not yet determined our implementation method.

In February 2016, the FASB issued ASU No. 2016-02, Leases, which requires the balance sheet recognition of lease assets and lease liabilities by lessees for leases previously classified as operating leases under prior GAAP. We will be required to adopt the new standard in annual and interim periods beginning January 1, 2019. Lessees and lessors will be required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The modified retrospective approach includes a number of optional practical expedients that entities may elect to apply. These practical expedients relate to the identification and classification of leases that commenced before the effective date, initial direct costs for leases that commenced before the effective date, and the ability to use hindsight in evaluating lessee options to extend or terminate a lease or to purchase the underlying asset. We have not yet evaluated the standard nor determined our implementation method upon adoption or what impact adoption will have on our financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

Interest rate risk – Our outstanding debt at December 31, 2015, consisted entirely of fixed-rate debt with a carrying value of $2.692 billion and a weighted-average annual interest rate of 5.6%. Due to the fixed-rate nature of our debt, management believes the risk of loss due to changes in market interest rates is not material.

Currency exchange rate risk – A substantial majority of our revenues are received in U.S. dollars, which is our functional currency. However, in certain countries in which we operate, local laws or contracts may require us to receive payment in the local currency.
We are exposed to foreign currency exchange risk to the extent the amount of our monetary assets denominated in the foreign currency differs from our obligations in that foreign currency. In order to mitigate the effect of exchange rate risk, we attempt to limit foreign currency holdings to the extent they are needed to pay liabilities in the local currency. In the past, we have entered into spot purchases or short-term derivative transactions, such as forward exchange contracts, with one-month durations. We did not enter into such transactions for the purpose of speculation, trading or investing in the market and we believe that our use of forward exchange contracts has not exposed us to material credit risk or other material market risk. Although our risk policy allows us to enter into such forward exchange

contracts, we do not currently anticipate entering into such transactions in the future and had no such contracts outstanding as of December 31, 2015.

Commodity price risk – Fluctuating commodity prices affect our future earnings materially to the extent that they influence demand for our products and services.

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
Rowan Companies plc
Houston, Texas

We have audited the accompanying consolidated balance sheets of Rowan Companies plc and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, changes in shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Rowan Companies plc and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, based on the criteria established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2016 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 26, 2016

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ROWAN COMPANIES PLC

MANAGEMENT’S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Rowan is responsible for establishing and maintaining adequate internal control over financial reporting for the Company as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal controls were designed to provide reasonable assurance as to the reliability of our financial reporting and the preparation and presentation of consolidated financial statements in accordance with accounting principles generally accepted in the United States, as well as to safeguard assets from unauthorized use or disposition.

We are required to assess the effectiveness of our internal controls relative to a suitable framework. The Committee of Sponsoring Organizations of the Treadway Commission (COSO) in its Internal Control - Integrated Framework (2013), developed a formalized, organization-wide framework that embodies five interrelated components — the control environment, risk assessment, control activities, information and communication and monitoring, as they relate to three internal control objectives — operating effectiveness and efficiency, financial reporting reliability and compliance with laws and regulations.

Our assessment included an evaluation of the design of our internal control over financial reporting relative to COSO and testing of the operational effectiveness of our internal control over financial reporting. Based upon our assessment, we have concluded that our internal controls over financial reporting were effective as of December 31, 2015.

The registered public accounting firm Deloitte & Touche LLP has audited Rowan’s consolidated financial statements included in our 2015 Annual Report on Form 10-K and has issued an attestation report on the Company’s internal control over financial reporting.

/s/ THOMAS P. BURKE Thomas P. Burke	/s/ STEPHEN M. BUTZ Stephen M. Butz
Chief Executive Officer	Executive Vice President, Chief Financial Officer and Treasurer
February 26, 2016	February 26, 2016

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Rowan Companies plc
Houston, Texas

We have audited the internal control over financial reporting of Rowan Companies plc and subsidiaries (the "Company") as of December 31, 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2015, of the Company and our report dated February 26, 2016, expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 26, 2016

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ROWAN COMPANIES PLC

CONSOLIDATED BALANCE SHEETS

	December 31, 2015	2014
	(In thousands, except shares)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$484,228	$339,154
Receivables - trade and other	410,519	545,204
Prepaid expenses and other current assets	26,528	27,096
Deferred income taxes - net	—	27,485
Total current assets	921,275	938,939
PROPERTY, PLANT AND EQUIPMENT:		
Drilling equipment	8,930,434	7,639,171
Construction in progress	—	1,023,646
Other property and equipment	137,659	137,365
Property, plant and equipment - gross	9,068,093	8,800,182
Less accumulated depreciation and amortization	1,662,261	1,367,970
Property, plant and equipment - net	7,405,832	7,432,212
Other assets	20,160	21,199
TOTAL ASSETS	$8,347,267	$8,392,350
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable - trade	$109,574	$102,773
Deferred revenues	33,062	36,189
Accrued liabilities	186,035	194,259
Total current liabilities	328,671	333,221
Long-term debt	2,692,419	2,788,482
Other liabilities	357,923	368,266
Deferred income taxes - net	195,795	210,982
Commitments and contingent liabilities (Note 7)	—	—
SHAREHOLDERS' EQUITY:		
Class A Ordinary Shares, $0.125 par value, 125,947,424 and 124,828,807 shares issued at December 31, 2015 and 2014, respectively	15,743	15,604
Additional paid-in capital	1,458,532	1,436,910
Retained earnings	3,509,792	3,466,993
Cost of 1,129,440 and 264,903 treasury shares at December 31, 2015 and 2014, respectively	(12,223)	(7,990)
Accumulated other comprehensive loss	(199,385)	(220,118)
Total shareholders' equity	4,772,459	4,691,399

TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$8,347,267	$8,392,350

See Notes to Consolidated Financial Statements.

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ROWAN COMPANIES PLC

CONSOLIDATED STATEMENTS OF INCOME

	Years ended December 31,		
	2015	2014	2013
	(In thousands, except per share amounts)		
REVENUES	$2,137,018	$1,824,383	$1,579,284
COSTS AND EXPENSES:			
Direct operating costs (excluding items below)	993,087	991,340	860,893
Depreciation and amortization	391,418	322,641	271,008
Selling, general and administrative	115,779	125,834	131,373
Gain on disposals of property and equipment	(7,703)	(1,778)	(20,119)
Gain on litigation settlement	—	(20,875)	—
Material charges and other operating expenses	337,347	573,950	4,453
Total costs and expenses	1,829,928	1,991,112	1,247,608
INCOME (LOSS) FROM OPERATIONS	307,090	(166,729)	331,676
OTHER INCOME (EXPENSE):			
Interest expense, net of interest capitalized	(145,317)	(103,934)	(69,794)
Interest income	1,129	1,861	1,578
Loss on debt extinguishment	(1,482)	—	—
Other - net	(3,710)	(805)	(2,221)
Total other income (expense) - net	(149,380)	(102,878)	(70,437)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	157,710	(269,607)	261,239
Provision (benefit) for income taxes	64,399	(150,732)	8,663
NET INCOME (LOSS) FROM CONTINUING OPERATIONS	93,311	(118,875)	252,576
DISCONTINUED OPERATIONS, NET OF TAX	—	4,023	—
NET INCOME (LOSS)	$93,311	$(114,852)	$252,576
INCOME (LOSS) PER SHARE - BASIC:			
Income (loss) from continuing operations	$0.75	$(0.96)	$2.04
Discontinued operations	$—	$0.03	$—
Net income (loss)	$0.75	$(0.93)	$2.04
INCOME (LOSS) PER SHARE - DILUTED:			
Income (loss) from continuing operations	$0.75	$(0.96)	$2.03
Discontinued operations	$—	$0.03	$—
Net income (loss)	$0.75	$(0.93)	$2.03

See Notes to Consolidated Financial Statements.

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ROWAN COMPANIES PLC

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years ended December 31,		
	2015	2014	2013
	(In thousands)		
NET INCOME (LOSS)	$93,311	$(114,852)	$252,576
OTHER COMPREHENSIVE INCOME (LOSS)			
Net changes in pension and other postretirement plan assets and benefit obligations recognized in other comprehensive income, net of income tax expense (benefit) of $3,446, ($46,944), and $34,092, respectively	6,964	(87,293)	63,315
Net reclassification adjustments for amounts recognized in net income as a component of net periodic benefit cost, net of income tax expense of $7,386, $5,261, and $8,250, respectively	13,769	9,824	15,322
	20,733	(77,469)	78,637
COMPREHENSIVE INCOME (LOSS)	$114,044	$(192,321)	$331,213

See Notes to Consolidated Financial Statements.

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ROWAN COMPANIES PLC

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS’ EQUITY

	Shares outstanding	Class A Ordinary Shares/ Common stock	Additional paid-in capital	Retained earnings	Treasury shares	Accumulated other comprehensive income (loss)	Total shareholders' equity
	(In thousands)						
Balance, January 1, 2013	124,211	$15,593	$1,372,135	$3,366,964	$(1,886)	$(221,082)	$4,531,724
Net shares issued (acquired) under share-based compensation plans	26	4	2,330	—	(4,076)	—	(1,742)
Share-based compensation	—	—	27,056	—	—	—	27,056
Excess tax benefit from share-based awards	—	—	3,690	—	—	—	3,690
Retirement benefit adjustments, net of taxes of $42,342	—	—	—	—	—	78,637	78,637
Other	—	—	1,820	—	—	—	1,820
Net income	—	—	—	252,576	—	—	252,576
Balance, December 31, 2013	124,237	15,597	1,407,031	3,619,540	(5,962)	(142,445)	4,893,761
Net shares issued (acquired) under share-based compensation plans	327	7	1,566	—	(2,028)	—	(455)
Share-based compensation	—	—	28,445	—	—	—	28,445
Excess tax benefit (shortfall) from share-based awards	—	—	(132)	—	—	—	(132)
Retirement benefit adjustments, net of tax benefit of $41,683	—	—	—	—	—	(77,469)	(77,469)
Dividends	—	—	—	(37,695)	—	—	(37,695)
Other	—	—	—	—	—	(204)	(204)
Net loss	—	—	—	(114,852)	—	—	(114,852)
Balance, December 31, 2014	124,564	15,604	1,436,910	3,466,993	(7,990)	(220,118)	4,691,399
Net shares issued (acquired) under share-based compensation plans	254	139	395	—	(4,233)	—	(3,699)
	—	—	23,830	—	—	—	23,830

Share-based compensation							
Excess tax benefit (shortfall) from share-based awards	—	—	(2,603)	—	—	—	(2,603)
Retirement benefit adjustments, net of taxes of $10,832	—	—	—	—	—	20,733	20,733
Dividends	—	—	—	(50,512)	—	—	(50,512)
Net income	—	—	—	93,311	—	—	93,311
Balance, December 31, 2015	124,818	$15,743	$1,458,532	$3,509,792	$(12,223)	$(199,385)	$4,772,459

See Notes to Consolidated Financial Statements.

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ROWAN COMPANIES PLC

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years ended December 31,		
	2015	2014	2013
	(In thousands)		
CASH PROVIDED BY OPERATIONS:			
Net income (loss)	$93,311	$(114,852)	$252,576
Adjustments to reconcile net income (loss) to net cash provided by operations:			
Depreciation and amortization	392,735	322,641	271,008
Provision for pension and postretirement benefits	33,978	25,117	32,010
Share-based compensation expense	33,627	34,547	33,931
Other postretirement benefit claims paid	(4,408)	(4,125)	(3,470)
Gain on disposals of property, plant and equipment	(7,703)	(3,691)	(20,119)
Deferred income taxes	(1,137)	(182,544)	(33,559)
Contributions to pension plans	(11,339)	(54,834)	(18,860)
Asset impairment charges	329,781	573,950	4,453
Non-cash loss on debt extinguishment	510	—	—
Changes in current assets and liabilities:			
Receivables - trade and other	134,685	(200,658)	30,784
Prepaid expenses and other current assets	568	16,328	9,583
Accounts payable	23,201	(20,629)	32,373
Accrued income taxes	10,662	4,891	(17,714)
Deferred revenues	(3,127)	(18,326)	2,175
Other current liabilities	(13,094)	72,897	(12,441)
Net changes in other noncurrent assets and liabilities	(15,258)	(27,753)	60,446
Net cash provided by operations	996,992	422,959	623,176
CASH USED IN INVESTING ACTIVITIES:			
Capital expenditures	(722,889)	(1,958,227)	(607,311)
Proceeds from disposals of property, plant and equipment	19,373	21,987	44,550
Net cash used in investing activities	(703,516)	(1,936,240)	(562,761)
CASH PROVIDED BY FINANCING ACTIVITIES:			
Proceeds from borrowings	220,000	793,380	—
Dividends paid	(50,512)	(37,695)	—
Debt issue costs	—	(687)	—
Repayments of borrowings	(317,890)	—	—
Proceeds from exercise of share options	—	4,725	2,911
Excess tax benefits from share-based compensation	—	(132)	3,690
Other	—	—	1,820
Net cash provided by (used in) financing activities	(148,402)	759,591	8,421
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	145,074	(753,690)	68,836
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	339,154	1,092,844	1,024,008
CASH AND CASH EQUIVALENTS, END OF PERIOD	$484,228	$339,154	$1,092,844

See Notes to Consolidated Financial Statements.

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NOTE 1 – NATURE OF OPERATIONS AND BASIS OF PRESENTATION

Rowan Companies plc, a public limited company incorporated under the laws of England and Wales, is a global provider of offshore contract drilling services to the international oil and gas industry. Our fleet currently consists of 31 mobile offshore drilling units, including 27 self-elevating jack-up drilling units and four ultra-deepwater drillships. We contract our drilling rigs, related equipment and work crews primarily on a day-rate basis in markets throughout the world, currently including the United States Gulf of Mexico (US GOM), United Kingdom (U.K.) and Norwegian sectors of the North Sea, the Middle East and Trinidad.

The consolidated financial statements included herein are presented in United States (U.S.) dollars and include the accounts of Rowan Companies plc ("Rowan plc") and its direct and indirect subsidiaries. Unless the context otherwise requires, the terms “Rowan,” “Company,” “we,” “us” and “our” are used to refer to Rowan plc and its consolidated subsidiaries. Intercompany balances and transactions have been eliminated in consolidation.

The financial information presented in this report does not constitute the Company's statutory accounts within the meaning of the U.K. Companies Act 2006 for the years ended December 31, 2015 or 2014. The audit of the statutory accounts for the year ended December 31, 2015, was not complete as of February 26, 2016. These accounts will be finalized by the directors on the basis of the financial information presented herein and will be delivered to the Registrar of Companies in the U.K.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue and Expense Recognition

Our drilling contracts generally provide for payment on a daily rate basis, and revenues are recognized as the work progresses with the passage of time. We occasionally receive lump-sum payments at the outset of a drilling assignment for equipment moves or modifications. Lump-sum fees received for equipment moves (and related costs) and fees received for equipment modifications or upgrades are initially deferred and amortized on a straight-line basis over the primary term of the drilling contract. The costs of contractual equipment modifications or upgrades and the costs of the initial move of newly acquired rigs are capitalized and depreciated in accordance with the Company’s fixed asset capitalization policy. The costs of moving equipment while not under contract are expensed as incurred. Revenues received but unearned are included in current and long-term liabilities and totaled $50.8 million and $60.2 million at December 31, 2015 and 2014, respectively. Deferred contract costs are included in prepaid expenses and other assets and totaled $4.4 million and $5.4 million at December 31, 2015 and 2014, respectively.

We recognize revenue for certain reimbursable costs. Each reimbursable item and amount is stipulated in the Company’s contract with the customer, and such items and amounts frequently vary between contracts. We recognize reimbursable costs on the gross basis, as both revenues and expenses, because we are the primary obligor in the arrangement, have discretion in supplier selection, are involved in determining product or service specifications and assume full credit risk related to the reimbursable costs.

Cash Equivalents

Cash equivalents consist of highly liquid temporary cash investments with maturities no greater than three months at the time of purchase.

Accounts Receivable and Allowance for Doubtful Accounts

The Company assesses the collectability of receivables and records adjustments to an allowance for doubtful accounts, which is recorded as an offset to accounts receivable, to cover the risk of credit losses. The allowance is based on historical and other factors that predict collectability, including write-offs, recoveries and the monitoring of credit quality. No allowance for doubtful accounts was required at December 31, 2015 or 2014.

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The following table sets forth the components of Receivables - trade and other at December 31 (in thousands):

	2015	2014
Trade	$395,694	$524,712
Income tax	4,463	6,315
Other	10,362	14,177
Total receivables - trade and other	$410,519	$545,204

Property and Depreciation

We provide depreciation for financial reporting purposes under the straight-line method over the asset's estimated useful life from the date the asset is placed into service until it is sold or becomes fully depreciated. In 2014, we reduced salvage values for our jack-up rigs from 20 percent to 10 percent of historical cost effective December 31, 2014, in connection with the completion of our asset impairment test. Estimated useful lives and salvage values are presented below:

	Life (in years)	Salvage Value	
Jack-up drilling rigs:			
Hulls	25 to 35	10	%
Legs	25 to 30	10	%
Quarters	25	10	%
Drilling equipment	5 to 25	0% to 10%	
Drillships:			
Hulls	35	10	%
Drilling equipment	5 to 25	0% to 10%	
Drill pipe and tubular equipment	4	10	%
Other property and equipment	3 to 30	various	

Expenditures for new property or enhancements to existing property are capitalized and depreciated over the asset's estimated useful life. As assets are sold or retired, property cost and related accumulated depreciation are removed from the accounts, and any resulting gain or loss is included in results of operations. The Company capitalizes a portion of interest cost incurred during the construction period. We capitalized interest in the amount of $16.2 million in 2015, $57.6 million in 2014 and $48.7 million in 2013.

Expenditures for maintenance and repairs are charged to operations as incurred and totaled $129 million in 2015, $161 million in 2014 and $152 million in 2013.

Impairment of Long-lived Assets

We review the carrying values of long-lived assets for impairment whenever events or changes in circumstances indicate their carrying amounts may not be recoverable. For assets held and used, we determine recoverability by evaluating the undiscounted estimated future net cash flows based on projected day rates, operating costs and utilization of the asset under review. When the impairment of an asset is indicated, we measure the amount of impairment as the amount by which the asset's carrying amount exceeds its estimated fair value. We measure fair value by estimating discounted future net cash flows under various operating scenarios (an income approach) and by assigning probabilities to each scenario in order to determine an expected value. The lowest level of inputs we use to value assets held and used in the business are categorized as "significant unobservable inputs," which are Level 3 inputs in the fair value hierarchy. For assets held for sale, we measure fair value based on equipment broker quotes, less anticipated selling costs, which are considered Level 3 inputs in the fair value hierarchy.

In 2015, we conducted an impairment test of our assets and determined that the carrying values for ten of our jack-up drilling units aggregating $457.8 million were not recoverable from their undiscounted estimated future cash flows and exceeded the rigs' estimated fair values. As a result, we recognized a non-cash impairment charge of $329.8 million in 2015. In 2014, we conducted an impairment test and determined that the carrying values for twelve of our jack-ups aggregating $840.8 million were not recoverable, and as a result, we recognized a non-cash impairment charge of $565.7 million in 2014. We measured fair values using the income approach described above. Our fair value estimates required us to use significant unobservable inputs including assumptions related to future demand for drilling services, estimated availability of rigs and future day rates, among others. The impairments recognized in 2015 and 2014 on our jack-up rigs are included in jack-up operations in the segment information in Note 12.

Additionally, in 2014, we recognized an $8.3 million non-cash impairment charge for the carrying value of a Company aircraft, which was used to support operations. We sold the aircraft later in 2014 and recognized an immaterial loss on sale. The asset had a carrying value of $12.7 million prior to the write-down. The amount of the impairment was based on actual sales prices for similar equipment obtained from a third-party dealer of such equipment. Quoted prices in active markets for similar equipment are considered a Level 2 input in the fair value hierarchy. The impairment recognized on the Company aircraft in 2014 is included in the "unallocated costs and other" column of the segment information in Note 12.

In 2013, we recognized a $4.5 million non-cash impairment charge for a dock and storage facility, which had a carrying value of $23.5 million prior to the write-down. The impairment charge in 2013 is included in jack-up operations in the segment information in Note 12.

Impairment charges are included in material charges and other operating expenses on the Consolidated Statements of Income.

Share-based Compensation

We recognize compensation cost for employee share-based awards on a straight-line basis over the requisite 36-month service period. For employees who are retirement-eligible at the grant date or who will become retirement-eligible within six months of the grant date, compensation cost is recognized over a minimum period of six months. Compensation cost for employees who become retirement eligible after six months following the grant date but before the 36-month maximum service period is amortized over the period from the grant date to the date the employee meets the retirement eligibility requirements.

Fair value of restricted shares and restricted share units awarded to employees is based on the market price of the stock on the date of grant. Compensation cost is recognized for awards that are expected to vest and is adjusted in subsequent periods if actual forfeitures differ from estimates.

Restricted share units granted to non-employee directors ("Director RSUs") vest one year following the grant date but may not be settled until the director terminates service from the board. Compensation cost is recognized over the one-year service period. Director RSUs may be settled in cash and/or shares of stock and are accounted for under the liability method of accounting. Fair value is based on the market price of the underlying stock on the grant date, and compensation expense is adjusted for changes in fair value at each report date through the settlement date.

Performance-based awards consist of Performance Units, in which the payment is contingent on the Company's total shareholder return relative to an industry peer group. Fair value of Performance Units is determined using a Monte-Carlo simulation model. Performance Units are settled in cash and accounted for under the liability method of accounting. Compensation cost is recognized on a straight-line basis over the service period and is adjusted for changes in fair value at each report date through the vest date.

Fair value of share appreciation rights ("SARs") is determined using the Black-Scholes option pricing model. The Company uses the simplified method for determining the expected life of SARs, because it does not have sufficient historical exercise data to provide a reasonable basis on which to estimate expected term, as permitted under US GAAP. The Company has not granted any SARs since 2013. The Company intends to share-settle SARs that are exercised and has therefore accounted for them as equity awards.

Foreign Currency Transactions

A substantial majority of our revenues are received in U.S. dollars, which is our functional currency. However, in certain countries in which we operate, local laws or contracts may require us to receive payment in the local currency. We are exposed to foreign currency exchange risk to the extent the amount of our monetary assets denominated in the foreign currency differs from our obligations in that foreign currency. In order to mitigate the effect of exchange rate risk, we attempt to limit foreign currency holdings to the extent they are needed to pay liabilities in the local currency. In the past, we have entered into spot purchases or short-term derivative transactions, such as forward exchange contracts, with one-month durations. We did not enter into such transactions for the purpose of speculation, trading or investing in the market and we believe that our use of forward exchange

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contracts has not exposed us to material credit risk or other material market risk. Although our risk policy allows us to enter into such forward exchange contracts, we do not currently anticipate entering into such transactions in the future and had no such contracts outstanding as of December 31, 2015.

At December 31, 2015 and December 31, 2014, we held Egyptian pounds in the amount of $13.5 million and $16.3 million, respectively, which are classified as other noncurrent assets. We ceased drilling operations in Egypt in 2014, and are currently working to obtain access to the funds for use outside Egypt to the extent they are not utilized. We can provide no assurance we will be able to convert or utilize such funds in the future.

Non-U.S. dollar transaction gains and losses are recognized in “other income” on the Consolidated Statements of Income. The Company recognized net currency exchange gains of $3.9 million and $0.05 million in 2015 and 2014, respectively, and a net exchange loss of $2.3 million in 2013.

Income Taxes

Rowan recognizes deferred income tax assets and liabilities for the estimated future tax consequences of differences between the financial statement and tax bases of assets and liabilities. Valuation allowances are provided against deferred tax assets that are not likely to be realized. Interest and penalties related to income taxes are included in income tax expense.

The Company does not provide deferred income taxes on undistributed earnings of its non-U.K. subsidiaries, including non-U.S. subsidiaries of the Company's wholly owned subsidiary, Rowan Companies Inc. (RCI). It is the Company’s policy and intention to permanently reinvest earnings of non-U.S. subsidiaries of RCI outside the U.S. Should the non-U.S. subsidiaries of RCI make a distribution from these earnings, we may be subject to additional U.S. income taxes. Generally, earnings of non-U.K. subsidiaries in which RCI does not have a direct or indirect ownership interest can be distributed to the Company without the imposition of either U.K. or local country tax. See Note 11 for further information regarding the Company’s income taxes.

Income Per Common Share

Basic income per share is computed by dividing income available to common shareholders by the weighted-average number of common shares outstanding during the period. Diluted income per share includes the additional effect of all potentially dilutive securities outstanding during the period, which includes nonvested restricted stock, restricted stock units, share options and appreciation rights granted under share-based compensation plans.

A reconciliation of shares for basic and diluted income per share is set forth below. There were no income adjustments to the numerators of the basic or diluted computations for the periods presented (in thousands):

	2015	2014	2013
Average common shares outstanding	124,508	124,067	123,517
Add dilutive securities:			
Nonvested restricted shares and restricted share units	585	—	542
Share options and appreciation rights	110	—	409
Average shares for diluted computations	125,203	124,067	124,468

Share options, appreciation rights and restricted share units granted under share-based compensation plans are antidilutive and excluded from diluted earnings per share when the hypothetical number of shares that could be repurchased under the treasury stock method exceeds the number of shares that can be exercised, or when the Company reports a net loss from continuing operations. Antidilutive shares, which could potentially dilute earnings per share in the future, are set forth below (in thousands):

	2015	2014	2013
Share options and appreciation rights	1,249	2,234	1,065
Nonvested restricted shares and restricted share units	1,092	619	—
Total potentially dilutive shares	2,341	2,853	1,065

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Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers, which sets forth a global standard for revenue recognition and replaces most existing industry-specific guidance. We will be required to adopt the new standard in annual and interim periods beginning January 1, 2018. The amendments may be applied retrospectively to each prior period presented or retrospectively with the cumulative effect recognized as of the date of initial application. We are evaluating the standard and have not yet determined our implementation method upon adoption or what impact adoption will have on our financial statements.

In February 2015, the FASB issued ASU No. 2015-02, Amendments to the Consolidation Analysis, which changes the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. We will be required to adopt the new standard in annual and interim periods beginning January 1, 2016. We do not expect adoption of the new standard will have a material effect on our financial statements.

In April 2015, the FASB issued ASU No. 2015-03, Simplifying the Presentation of Debt Issuance Costs, which changes the presentation of debt issuance costs in financial statements. Under this ASU, an entity presents such costs in the balance sheet as a direct deduction from the related debt liability rather than as an asset. We adopted the new standard effective December 31, 2015. As a result of adoption, we reclassified unamortized debt issue costs in the amount of $16.4 million and $18.8 million as of December 31, 2015 and 2014, respectively, and reduced the carrying value of long-term debt by the same amounts.

In November 2015, the FASB issued ASU No. 2015-17, Balance Sheet Classification of Deferred Taxes, which requires entities to present deferred tax assets and deferred tax liabilities in balance sheets as noncurrent. We will be required to adopt the new standard in annual and interim periods beginning January 1, 2017, with early adoption permitted. The amendments in this ASU may be applied either prospectively to all deferred tax liabilities and assets or retrospectively to all periods presented. We are evaluating the standard and have not yet determined our implementation method.

In February 2016, the FASB issued ASU No. 2016-02, Leases, which requires the balance sheet recognition of lease assets and lease liabilities by lessees for leases previously classified as operating leases under prior GAAP. We will be required to adopt the new standard in annual and interim periods beginning January 1, 2019. Lessees and lessors will be required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The modified retrospective approach includes a number of optional practical expedients that entities may elect to apply. These practical expedients relate to the identification and classification of leases that commenced before the effective date, initial direct costs for leases that commenced before the effective date, and the ability to use hindsight in evaluating lessee options to extend or terminate a lease or to purchase the underlying asset. We have not yet evaluated the standard nor determined our implementation method upon adoption or what impact adoption will have on our financial statements.

NOTE 3 – DISCONTINUED OPERATIONS

In 2014 we sold a land rig that was retained in connection with the 2011 sale of the Company's manufacturing business. The Company received $6.0 million in cash resulting in a $4.0 million gain, net of a $2.1 million income tax benefit. The net gain on sale is classified as discontinued operations.

NOTE 4 – ACCRUED LIABILITIES

Accrued liabilities at December 31 consisted of the following (in thousands):

	2015	2014
Pension and other postretirement benefits	$31,389	$26,219
Compensation and related employee costs	73,628	88,186
Interest	44,338	47,414
Income taxes	23,927	13,265
Other	12,753	19,175
Total accrued liabilities	$186,035	$194,259

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NOTE 5 – LONG-TERM DEBT

Long-term debt at December 31 consisted of the following (in thousands):

	2015	2014
5% Senior Notes, due September 2017 ($366.6 million principal amount; 5.1% effective rate)	$365,494	$398,009
7.875% Senior Notes, due August 2019 ($435.5 million principal amount; 8.0% effective rate)	432,870	496,150
4.875% Senior Notes, due June 2022 ($700 million principal amount; 4.6% effective rate)	706,236	707,206
4.75% Senior Notes, due January 2024 ($400 million principal amount; 4.8% effective rate)	397,069	396,704
5.4% Senior Notes, due December 2042 ($400 million principal amount; 5.5% effective rate)	394,720	394,524
5.85% Senior Notes, due January 2044 ($400 million principal amount; 5.9% effective rate)	396,030	395,889
Total long-term debt	$2,692,419	$2,788,482

As of December 31, 2015, no principal payments are required with respect to our outstanding debt through 2016; $366.6 million becomes due in September 2017, and $435.5 million becomes due in August 2019.

In January 2014, Rowan plc, as guarantor, and its 100% owned subsidiary, RCI, as issuer, completed the issuance and sale in a public offering of $400 million aggregate principal amount of its 4.75% Senior Notes due 2024 at a price to the public of 99.898% of the principal amount and $400 million aggregate principal amount of its 5.85% Senior Notes due 2044 at a price to the public of 99.972% of the principal amount. Net proceeds of the offering were approximately $792 million, which the Company used in its rig construction program and for general corporate purposes.

In May 2015, the Company amended and restated its revolving credit agreement to increase the borrowing capacity under the facility from $1 billion to $1.5 billion and to extend the maturity date by one year to January 2020. There were no amounts drawn under the revolving credit facility at December 31, 2015. In January 2016, the Company further amended the revolving credit agreement to extend the maturity date by one year to January 2021. Availability under the facility is $1.5 billion through January 23, 2019, declining to $1.44 billion through January 23, 2020, and to approximately $1.29 billion through the maturity in 2021.

During 2015, we paid $101.1 million in cash to retire $97.9 million aggregate principal amount 5% Notes due 2017 and 7.875% Notes due 2019, plus accrued interest, and recognized a $1.5 million loss on early extinguishment of debt.

The 5% Senior Notes due 2017, 7.875% Senior Notes due 2019, 4.875% Senior Notes due 2022, 4.75% Senior Notes due 2024, 5.4% Senior Notes due 2042, and 5.85% Senior Notes due 2044 (together, the "Senior Notes") are RCI's senior unsecured obligations and rank senior in right of payment to all of its subordinated indebtedness and pari passu in right of payment with any of RCI's future senior indebtedness, including any indebtedness under RCI's senior revolving credit facility. The Senior Notes rank effectively junior to RCI's future secured indebtedness, if any, to the extent of the value of its assets constituting collateral securing that indebtedness and to all existing and future indebtedness of its subsidiaries (other than indebtedness and liabilities owed to RCI).

All or part of the Senior Notes may be redeemed at any time for an amount equal to 100% of the principal amount plus accrued and unpaid interest to the redemption date plus the applicable make-whole premium, if any.

The Senior Notes are fully and unconditionally guaranteed on a senior and unsecured basis by Rowan plc (see Note 15).

Restrictive provisions in the Company's bank credit facility agreement limit consolidated debt to 60% of book capitalization. Our consolidated debt to total capitalization ratio at December 31, 2015, was 36%.

Other provisions of our debt agreements limit the ability of the Company to create liens that secure debt, engage in sale and leaseback transactions, merge or consolidate with another company and, in the event of noncompliance, restrict investment activities and asset purchases and sales, among other things. The Company was in compliance with its debt covenants at December 31, 2015.

NOTE 6 – FAIR VALUE MEASUREMENTS

Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the

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measurement date. The fair value hierarchy prescribed by US GAAP requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The three levels of inputs that may be used to measure fair value are:

- Level 1 – Quoted prices for identical instruments in active markets;
- Level 2 – Quoted market prices for similar instruments in active markets; quoted prices for identical instruments in markets that are not active, and model-derived valuations in which all significant inputs and significant value drivers are observable in active markets; and
- Level 3 – Valuations derived from valuation techniques in which one or more significant inputs or significant value drivers are unobservable, such as those used in pricing models or discounted cash flow methodologies, for example.

The applicable level within the fair value hierarchy is the lowest level of any input that is significant to the fair value measurement.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Assets and liabilities measured at fair value on a recurring basis at December 31 are presented below (in thousands):

		Estimated fair value measurements		
	Carrying value	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
December 31, 2015:				
Assets - cash equivalents	$465,388	$465,388	$—	$—
Other assets	13,508	13,508	—	—
December 31, 2014:				
Assets - cash equivalents	$314,570	$314,570	$—	$—
Other assets	16,304	16,304	—	—

At December 31, 2015 and 2014, we held Egyptian pounds in the amount of approximately $13.5 million and $16.3 million, respectively, which are classified as other noncurrent assets. We ceased drilling operations in Egypt in 2014, and are currently working to obtain access to the funds for use outside Egypt to the extent they are not utilized. We can provide no assurance we will be able to convert or utilize such funds in the future.

Trade receivables and trade payables, which are also required to be measured at fair value, have carrying values that approximate their fair values due to their short maturities.

Assets Measured at Fair Value on a Nonrecurring Basis

Assets measured at fair value on a nonrecurring basis and whose carrying values were remeasured during the year ended December 31 are set forth below (in thousands):

		Estimated fair value measurements			
	Carrying value	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total gains (losses)
2015:					
Property and equipment, net	$128,018	$—	$—	$128,018	$(329,781)

2014:					
Property and equipment, net	$275,148	$—	$—	$275,148	$(565,650)

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In 2015, we recognized non-cash asset impairment charges aggregating $329.8 million on ten of the Company's jack-up drilling units having an aggregate net carrying value of $457.8 million prior to the write-down. In 2014, we recognized asset impairment charges totaling $565.7 million on twelve jack-up drilling units having an aggregate net carrying value of $840.8 million prior to the write-down. See Note 2, "Impairment of Long-lived Assets."

Other Fair Value Measurements

Financial instruments not required to be measured at fair value consist of the Company's publicly traded debt securities. Our publicly traded debt securities are classified as long-term debt and had a carrying value of $2.692 billion at December 31, 2015, and an estimated fair value at that date aggregating $2.072 billion, compared to a carrying and fair value of $2.788 billion and $2.755 billion, respectively, at December 31, 2014. Fair values of our publicly traded debt securities were provided by a broker who makes a market in such securities and were measured using a market-approach valuation technique. Fair value was determined by adding a spread based on actual trades for that security (or a trader quote where actual trades were unavailable) to the applicable benchmark Treasury security with a comparable maturity in order to derive a current yield. The yield is then used to determine a price given the individual security's coupon rate and maturity. Such inputs are considered "significant other observable inputs," which are categorized as Level 2 inputs in the fair value hierarchy.

Concentrations of Credit Risk

We invest our excess cash primarily in time deposits and high-quality money market accounts at several large commercial banks with strong credit ratings, and therefore believe that our risk of loss is minimal.

The Company's customers largely consist of major international oil companies, national oil companies and large investment-grade exploration and production companies. We routinely evaluate the credit quality of potential customers. Three customers, Saudi Aramco, ConocoPhillips, and Anadarko accounted for 19%, 13% and 10%, respectively, of consolidated revenues in 2015 and 34%, 12%, and 9% respectively, of the consolidated trade receivable balance at December 31, 2015. In 2014, one customer accounted for 24% of consolidated revenues and 29% of the consolidated trade receivable balance at December 31, 2014. In 2013, one customer accounted for 26% and another accounted for 11% of consolidated revenues. The Company maintains reserves for credit losses when necessary and actual losses have been within management's expectations.

NOTE 7 – COMMITMENTS AND CONTINGENT LIABILITIES

The Company has operating leases covering office space and equipment. Certain of the leases are subject to escalations based on increases in building operating costs. Rental expense attributable to continuing operations was $13.2 million in 2015, $13.8 million in 2014 and $9.3 million in 2013.

At December 31, 2015, future minimum payments to be made under noncancelable operating leases were as follows (in thousands):

2016	$7,125
2017	5,770
2018	5,669
2019	5,673
2020	3,997
Later years	12,040
	$40,274

We had commitments for purchase obligations totaling $106 million at December 31, 2015.

We periodically employ letters of credit in the normal course of our business, and had outstanding letters of credit of approximately $4.2 million at December 31, 2015.

Uncertain tax positions – In 2009, the Company recognized certain tax benefits as a result of applying the facts of a third-party tax case to the Company’s situation. That case provided a more favorable tax treatment for certain foreign contracts entered into in prior years. Our position was challenged by the U.S. Internal Revenue Service ("IRS"). We appealed their findings and reached a settlement agreement in 2014 with respect to three of the four years under review in the amount of approximately $36 million,

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including interest, which we collected in 2014. A remaining year continues to be under examination. We plan to vigorously defend our position.

We are involved in various legal proceedings incidental to our businesses and are vigorously defending our position in all such matters. The Company believes that there are no known contingencies, claims or lawsuits that could have a material effect on its financial position, results of operations or cash flows.

NOTE 8 – SHARE-BASED COMPENSATION PLANS

Under the 2013 Rowan Companies plc Incentive Plan (the Plan), the Compensation Committee of the Company's Board of Directors is authorized to grant employees and nonemployee directors incentive awards covering up to 7,500,000 of our ordinary shares. The awards may be in the form of restricted share awards, restricted share units, options and share appreciation rights. In addition, the Compensation Committee may grant performance-based awards under the Plan, in which the amount earned is dependent on the achievement of certain long-term market or performance conditions over a specified period. As of December 31, 2015, there were 3,593,768 shares available for future grant under the Plan.

Compensation cost charged to expense under all share-based incentive awards is presented below (in thousands):

	2015	2014	2013
Restricted shares and restricted share units	$22,462	$23,577	$23,786
Share appreciation rights	1,147	3,724	6,412
Share options	—	—	23
Performance-based awards	10,018	7,246	3,710
Total compensation cost	$33,627	$34,547	$33,931

As of December 31, 2015, unrecognized compensation cost related to nonvested share-based compensation arrangements totaled $34.5 million, which is expected to be recognized over a weighted-average period of 1.5 years.

Restricted Shares – A restricted share represents an ordinary share subject to a vesting period that restricts its sale or transfer until the vesting period ends. In general, the restricted shares vest and the restrictions lapse in one-third increments each year over a three-year service period, or in some cases, cliff vest at the end of a three-year service period. Restricted share activity for the year ended December 31, 2015, is summarized below:

	Number of Shares	Weighted-average grant-date fair value per share
Nonvested at January 1, 2015	210,554	$35.13
Vested	(206,180)	35.14
Forfeited	(1,874)	35.47
Nonvested at December 31, 2015	2,500	$33.88

The aggregate fair value of restricted shares that vested in 2015, 2014 and 2013 was $4.1 million, $10.9 million and $16.2 million, respectively, based on share prices on the vesting dates.

Employee Restricted Share Units – Restricted share units (RSUs) are rights to receive a specified number of ordinary shares upon vesting. RSUs granted to employees typically vest in one-third increments over a three-year service period or in some cases cliff vest at the end of three years. Employee RSU activity for the year ended December 31, 2015, follows:

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	Number of Shares	Weighted-average grant-date fair value per share
Nonvested at January 1, 2015	1,132,153	$33.05
Granted	1,222,777	21.11
Vested	(440,083)	33.06
Forfeited	(171,121)	25.42
Nonvested at December 31, 2015	1,743,726	$25.42

The aggregate fair value of employee RSUs that vested in 2015, 2014 and 2013 was $8.9 million, $8.5 million and $0.5 million respectively.

Non-employee Director Restricted Share Units – RSUs granted to nonemployee directors generally cliff vest at the earlier of the first anniversary of the grant date or the next annual meeting of shareholders following the grant date and are settled in either cash, shares, or a combination thereof at the discretion of the Compensation Committee determined at the time the director terminates service to the Board. Non-employee director RSU activity for the year ended December 31, 2015, follows:

	Number of shares	Weighted-average grant-date fair value per share
Outstanding at January 1, 2015	267,438	$32.04
Granted	77,040	20.96
Settled	(44,336)	32.85
Outstanding at December 31, 2015	300,142	$29.51
Vested at December 31, 2015	229,101	$32.11

The number and aggregate settlement-date fair value of non-employee director RSUs settled during the year were as follows: 2015 – 44,336 RSUs at $0.9 million; 2014 – 37,251 RSUs at $1.2 million; 2013 – 23,928 RSUs at $0.8 million.

Non-employee director RSUs are accounted for under the liability method. Accordingly, other long-term liabilities at December 31, 2015 and 2014, included $4.7 million and $5.8 million, respectively, related to such awards.

Performance-based Awards – The Committee may grant awards in which payment is contingent upon the achievement of certain market or performance-based conditions over a period of time specified by the Committee. Payment of such awards may be in ordinary shares or in cash as determined by the Committee.

In February 2015, the Company granted to certain members of management performance units (P-Units) that have a target value of $100 per unit. The amount ultimately earned with respect to the P-Units will depend on the Company's total shareholder return (TSR) ranking compared to a group of peer companies over a three-year period ending December 31, 2017, and could range from zero to $200 per unit depending on performance. Twenty-five percent of the P-Units' value is determined by the Company's relative TSR ranking for each one-year period ended December 31, 2015, 2016, and 2017, respectively, and 25% of the P-Units' value is determined by the relative TSR ranking for the three-year period ended December 31, 2017. Vesting of awards and any payment with respect to the P-Units would not occur until the third anniversary following the grant date. Any employee who terminates employment with the Company prior to the third anniversary for any reason other than retirement will not receive any payment with respect to P-Units unless approved by the Compensation Committee. The Compensation Committee has determined that any amount earned with respect to P-Units granted in 2015 would be settled in cash.

The grant-date fair value of P-Units granted in 2015 was estimated to be $9.0 million. Fair value was estimated using the Monte Carlo simulation model, which considers the probabilities of the Company's TSR ranking at the end of each performance period, and the amount of the payout at each rank to determine the probability-weighted expected payout. The Company uses liability accounting to account for the P-Units. Compensation is recognized on a straight-line basis over a maximum period of three years from the grant date and is adjusted for changes in fair value through the vesting date.

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Liabilities for estimated P-Unit obligations at December 31, 2015, included $7.6 million and $11.4 million classified as short- and long-term, respectively. Liabilities for estimated P-Unit obligations at December 31, 2014, totaled $11.6 million, which was classified as long-term.

In 2015, we paid $2.7 million in cash to settle P-Units that vested during the year. No performance-based awards vested or settled in 2014 or 2013.

Share Appreciation Rights – Share appreciation rights (SARs) give the holder the right to receive ordinary shares at no cost to the employee, or cash at the discretion of the Committee, equal in value to the excess of the market price of a share on the date of exercise over the exercise price. All SARs granted have exercise prices equal to the market price of the underlying shares on the date of grant. SARs become exercisable in one-third annual increments over a three-year service period and expire ten years following the grant date. The Company intends to share-settle any exercises of SARs and has therefore accounted for SARs as equity awards.

Fair values of SARs granted were determined using the Black-Scholes option pricing model with the following weighted-average assumptions:

	2013
Expected life in years	6.0
Risk-free interest rate	1.058%
Expected volatility	41.11%
Weighted-average grant-date per-share fair value	$13.91

No SARs were granted in 2015 or 2014.

The Company uses the simplified method for determining the expected life of SARs because the Company does not have sufficient historical exercise data to provide a reasonable basis upon which to estimate expected term, as permitted under US GAAP.

SARs activity for the year ended December 31, 2015, is summarized below:

	Number of shares under SARs	Weighted-average exercise price	Weighted-average remaining contractual term (in years)	Aggregate intrinsic value (in thousands)
Outstanding at January 1, 2015	1,761,270	$30.94		
Forfeited or expired	(145,968)	34.10		
Outstanding at December 31, 2015	1,615,302	$30.66	4.3	$—
Exercisable at December 31, 2015	1,497,425	$30.37	4.1	$—

No SARs were exercised in 2015. The aggregate intrinsic value of SARs exercised in 2014 and 2013 was $0.9 million, and $0.5 million, respectively.

Share Options – Share options granted to employees generally became exercisable in one-third or one-quarter annual increments over a three- or four-year service period at a price generally equal to the market price of the Company's common shares on the date of grant. The Company has not granted share options since 2008. Unexercised options expire ten years after the grant date.

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Share option activity for the year ended December 31, 2015, is summarized below:

	Number of shares under option	Weighted-average exercise price	Weighted-average remaining contractual term (in years)	Aggregate intrinsic value (in thousands)
Outstanding at January 1, 2015	185,404	$22.96		
Forfeited or expired	(60,372)	26.97		
Outstanding at December 31, 2015	125,032	$21.02	2.4	$164
Exercisable at December 31, 2015	125,032	$21.02	2.4	$164

No options were exercised in 2015. The aggregate intrinsic value of options exercised in 2014 and 2013 was $1.4 million and $2.0 million, respectively.

Award modifications – In 2014, the Company accelerated the vesting of share-based awards and extended the exercise period for vested SARs held by two retiring employees whose awards would otherwise have been forfeited upon retirement. As a result of the modifications, the Company recognized additional compensation expense in 2014 in the amount of $1.7 million, net of forfeitures, which is included in selling, general and administrative expense. The Company valued the modified SARs assuming they are to be outstanding near or until such time as they expire.

NOTE 9 – PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

The Company provides defined-benefit pension, health care and life insurance benefits upon retirement for certain full-time employees. Pension benefits are provided under the Rowan Pension Plan and the Restoration Plan of Rowan Companies, Inc. (the “Rowan SERP”), and health care and life insurance benefits are provided under the Retiree Life & Medical Supplemental Plan of Rowan Companies, Inc. (the “Retiree Medical Plan”).

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The following table presents the changes in benefit obligations and plan assets for the years ended December 31 and the funded status and weighted-average assumptions used to determine the benefit obligation at each year end (dollars in thousands):

	2015 Pension benefits	Other benefits	Total	2014 Pension benefits	Other benefits	Total
Projected benefit obligations:						
Balance, January 1	$807,953	$73,578	$881,531	$679,880	$66,832	$746,712
Interest cost	31,911	2,870	34,781	32,680	3,025	35,705
Service cost	18,304	1,334	19,638	14,573	1,067	15,640
Actuarial (gain) loss	(40,265)	480	(39,785)	114,030	6,779	120,809
Plan amendments	(4,900)	(7,188)	(12,088)	259	—	259
Exchange rate changes	(1,027)	—	(1,027)	(1,215)	—	(1,215)
Benefits paid	(51,923)	(4,408)	(56,331)	(32,254)	(4,125)	(36,379)
Balance, December 31	760,053	66,666	826,719	807,953	73,578	881,531
Plan assets:						
Fair value, January 1	591,960	—	591,960	542,449	—	542,449
Actual return	(74)	—	(74)	27,596	—	27,596
Employer contributions	11,339	—	11,339	54,834	—	54,834
Exchange rate changes	(558)	—	(558)	(665)	—	(665)
Benefits paid	(51,923)	—	(51,923)	(32,254)	—	(32,254)
Fair value, December 31	550,744	—	550,744	591,960	—	591,960
Net benefit liabilities	$(209,309)	$(66,666)	$(275,975)	$(215,993)	$(73,578)	$(289,571)
Amounts recognized in Consolidated Balance Sheet:						
Accrued liabilities	$(22,249)	$(9,140)	$(31,389)	$(21,839)	$(4,380)	$(26,219)
Other liabilities (long-term)	(187,060)	(57,526)	(244,586)	(194,154)	(69,198)	(263,352)
Net benefit liabilities	$(209,309)	$(66,666)	$(275,975)	$(215,993)	$(73,578)	$(289,571)
Accumulated contributions in excess of (less than) net periodic benefit cost	$106,074	$(75,318)	$30,756	$124,248	$(75,522)	$48,726
Amounts not yet reflected in net periodic benefit cost:						
Actuarial (loss) gain	(336,670)	1,464	(335,206)	(360,753)	1,944	(358,809)
Prior service credit	21,287	7,188	28,475	20,512	—	20,512
Total accumulated other comprehensive loss	(315,383)	8,652	(306,731)	(340,241)	1,944	(338,297)
Net benefit liabilities	$(209,309)	$(66,666)	$(275,975)	$(215,993)	$(73,578)	$(289,571)
Weighted-average assumptions:						
Discount rate	4.54%	4.18%		4.12%	3.95%	
Rate of compensation increase	4.15%			4.15%		

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During 2015, we amended the eligibility requirement with respect to the Retiree Medical Plan to exclude any participant that was previously eligible and was under the age of 50 as of January 1, 2016. The effect of the change was to reduce the projected benefit obligation by $7.2 million, which is net of an estimated $4.4 million payment that is expected to be made in early 2016 to the affected participants.

The projected benefit obligations for pension benefits in the preceding table reflect the actuarial present value of benefits accrued based on services rendered to date and include the estimated effect of future salary increases. The accumulated benefit obligations, which are presented below for all plans in the aggregate at December 31, are based on services rendered to date, but exclude the effect of future salary increases (in thousands):

	2015	2014
Accumulated benefit obligation	$755,050	$801,749

Each of the Company's pension plans has a benefit obligation that exceeds the fair value of plan assets.

The Company estimates the following amounts, which are classified in accumulated other comprehensive loss, a component of shareholders' equity, will be recognized as net periodic benefit cost in 2016 (in thousands):

	Pension benefits	Other retirement benefits	Total
Actuarial (loss) gain	$(20,532)	$—	$(20,532)
Prior service credit	4,992	386	5,378
Total amortization	$(15,540)	$386	$(15,154)

The components of net periodic pension cost and the weighted-average assumptions used to determine net cost were as follows (dollars in thousands):

	2015	2014	2013
Service cost	$18,304	$14,573	$12,309
Interest cost	31,911	32,680	29,984
Expected return on plan assets	(41,598)	(41,592)	(38,305)
Recognized actuarial loss	25,674	19,861	28,454
Amortization of prior service cost	(4,519)	(4,507)	(4,736)
Net periodic pension cost	$29,772	$21,015	$27,706
Discount rate	3.97%	4.83%	4.16%
Expected return on plan assets	7.45%	8.00%	8.00%
Rate of compensation increase	4.15%	4.15%	4.15%

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The components of net periodic cost of other postretirement benefits and the weighted average discount rate used to determine net cost were as follows (dollars in thousands):

	2015	2014	2013
Service cost	$1,334	$1,067	$1,445
Interest cost	2,870	3,025	3,006
Amortization of prior service cost	—	(32)	(147)
Amortization of net (gain) loss	—	(237)	—
Net periodic cost of other postretirement benefits	$4,204	$3,823	$4,304
Discount rate	3.95%	4.74%	3.89%

The assumed health care cost trend rates used to measure the expected cost of retirement health benefits was 6.7% for 2016, gradually decreasing to 4.5% for 2026 and thereafter. A one-percentage-point change in the assumed health care cost trend rates would change the reported amounts as follows (in thousands):