ROWAN COMPANIES PLC
Form 10-K
February 27, 2019
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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, 2018

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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes þ No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

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 $2.1 billion as of June 30, 2018, based upon the closing price of the registrant's ordinary shares on the New York Stock Exchange of $16.22 per share.

The number of Class A ordinary shares, $0.125 par value, outstanding at February 21, 2019, was 127,294,643, which excludes 908,042 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 2019 Annual General Meeting of Shareholders	Part III, Items 10-14

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FORWARD-LOOKING STATEMENTS

Statements contained in this Annual Report on Form 10-K (this "Annual Report"), including in the documents incorporated by reference herein, 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; the proposed transaction with Ensco plc; dividend payments; share repurchases or repayment of debt; business strategies; expected utilization, day rates, revenue, operating expenses, contract terms, contract backlog and fleet status; performance of our joint venture with Saudi Aramco; capital expenditures; tax rates and positions; impairments; insurance coverages; access to financing and funding sources, including borrowings under our Existing Credit Facility and New Credit Facility; 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; divestiture of selected assets; expense management; the likely outcome of legal proceedings; the impact of competition and consolidation in the industry; the timing of acquisitions, dispositions and other business transactions; customer financial position; 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:

- failure, difficulties and delays in meeting conditions required for closing set forth in the agreement governing the Transaction with Ensco;
- the potential impact of the announcement or consummation of the Transaction with Ensco on relationships, including with employees, suppliers, customers, competitors, lenders and credit rating agencies;
- our ability to successfully integrate the operations of the Company and Ensco and to realize synergies and cost savings following the consummation of the Transaction;
- prices of oil and natural gas and industry expectations about future prices and impacts of regional or global financial or economic downturns;
- changes in the offshore drilling market, including fluctuations in worldwide rig supply and demand, competition or technology, including as a result of delivery of newbuild drilling units;
- variable levels of drilling activity and expenditures in the energy industry, whether as a result of actions by OPEC, global capital markets and liquidity, application of alternate energy sources, prices of oil and natural gas or otherwise, which may result in decreased demand and/or cause us to idle or stack, sell or scrap additional rigs;
- possible termination, suspension, renegotiation or cancellation of drilling contracts (with or without cause) as a result of general and industry economic conditions, distressed financial condition of our customers, force majeure, mechanical difficulties, delays, labor disturbances, strikes, performance or other reasons; payment or operational delays by our customers; or restructuring or insolvency of significant customers;
- changes or delays in actual contract commencement dates, contract option exercises, contract revenue and contract awards;
- our ability to enter into, and the terms of, future drilling contracts for drilling units whose contracts are expiring and drilling units currently idled or stacked;
- 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 availability of transport vessels, hazards, self-imposed drilling limitations and other delays due to weather conditions, work stoppages or otherwise, and the availability or high cost of insurance coverage for certain offshore perils or associated removal of wreckage or debris and other losses;
- regulatory, legislative or permitting requirements affecting drilling operations and other compliance obligations in the areas in which we operate;
- tax matters, including our effective tax rates, tax positions, results of audits, tax disputes, changes in tax laws, treaties and regulations, tax assessments and liabilities for taxes;

- our ability to realize the expected benefits of our joint venture with Saudi Aramco, including our ability to fund any required capital contributions, and increased risks of concentrated operations in the Middle East;

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- access to spare parts, equipment and personnel to maintain, service and upgrade our fleet;
- potential cost overruns and other risks inherent with repairs, inspections or upgrades of drilling units, unexpected delays in rig and equipment delivery and engineering or design issues, 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;
- operating hazards, including environmental or other liabilities, risks, expenses or losses, related to well-control issues, collisions, groundings, blowouts, fires, explosions, weather or hurricane delays or damage, losses or liabilities (including wreckage or debris removal) or otherwise;
- our ability to retain highly skilled personnel on commercially reasonable terms, whether due to competition, cost cutting initiatives, labor regulations, unionization 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, military or political demonstrations, acts of war, strikes, terrorism, piracy or outbreak or escalation of hostilities or other crises, which may result in expropriation, nationalization, confiscation, damage or deprivation of assets, extended business interruptions, suspended operations, or suspension and/or termination of contracts and payment disputes based on force majeure events;
- cyber-breaches of our corporate or offshore control networks;
- epidemics or other related travel restrictions which may result in business interruptions or shortages of available labor;
- the outcome of legal proceedings, or other claims or contract disputes, including inability to collect receivables or resolve significant contractual or day rate disputes, any renegotiation, nullification, cancellation or breach of contracts with customers or other parties;
- potential for asset impairments;
- our liquidity, adequacy of cash flows to meet obligations, or our ability to access or obtain financing and other sources of capital, such as in the debt or equity capital markets;
- volatility in currency exchange rates and limitations on our ability to use or convert illiquid currencies;
- effects of accounting changes and adoption of accounting policies;
- potential unplanned expenditures and funding requirements, including investments in pension plans and other benefit plans;
- system implementations and upgrades;
- economic volatility and political, legal and tax uncertainties following the June 23, 2016, vote in the U.K. to exit from the European Union ("Brexit") and any subsequent referendum in Scotland to seek independence from the U.K.;
- other important factors described from time to time in the reports filed by us with the SEC and the NYSE.

Should one or more of these risks or uncertainties materialize or should our underlying assumptions prove incorrect, actual results may vary materially from those indicated.

All forward-looking statements contained in this Annual Report speak only as of the date of this report 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 Annual Report, or to reflect the occurrence of unanticipated events, except as required by applicable law.

Other relevant factors are included in Part I, Item 1A, “Risk Factors,” of this Annual Report.

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GLOSSARY OF TERMS

The following frequently used abbreviations or acronyms are used in this Annual Report as defined below:

Abbreviation/Acronym	Definition
2017 Notes	The Company's 5% Senior Notes due 2017
2019 Notes	The Company's 7.875% Senior Notes due 2019
2022 Notes	The Company's 4.875% Senior Notes due 2022
2024 Notes	The Company's 4.75% Senior Notes due 2024
2025 Notes	The Company's 7.375% Senior Notes due 2025
2042 Notes	The Company's 5.4% Senior Notes due 2042
2044 Notes	The Company's 5.85% Senior Notes due 2044
ARO	Saudi Aramco Rowan Offshore Drilling Company
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
Board	Board of directors of the Company
Company	Rowan Companies plc together with its wholly-owned subsidiaries
BSEE	U.S. Bureau of Safety and Environmental Enforcement
Cobalt	Cobalt International Energy, L.P.
Company Compensation Committee	Compensation committee of the board of directors of the Company
Directors RSUs	Directors Deferred Restricted Share Units
Directors ND RSUs	Directors Non-Deferred Restricted Share Units
E.U.	European Union
EBT	Employee benefit trust of the Company
Ensco	Ensco plc, a public limited company organized under the laws of England and Wales
Exchange Act	Securities Exchange Act of 1934
Existing Credit Agreement	The Company's amended and restated senior unsecured revolving credit agreement entered into with a group of lenders on May 22, 2018, which matures January 23, 2021
Existing Credit Facility	Commitments in the amount of $310.7 million provided by a group of lenders under the Existing Credit Agreement
FASB	Financial Accounting Standards Board
FCPA	U.S. Foreign Corrupt Practices Act
FCX	Freeport-McMoRan Inc.
FMOG	Freeport-McMoRan Oil and Gas LLC
HPHT	High-pressure/high-temperature
IMO	International Maritime Organization
IRS	U.S. Internal Revenue Service
MARPOL 73/78	International Convention for the Prevention of Pollution from Ships, 1973 as modified by the Protocol of 1978
NOLs	Net Operating Loss Carryforwards
New Credit Agreement	The Company's senior unsecured revolving credit agreement entered into with a group of lenders on May 22, 2018, which matures May 22, 2023
New Credit Facility	Commitments in the amount of $955 million provided by a group of lenders under the New Credit Agreement
NYSE	The New York Stock Exchange
OPEC	Organization of Petroleum Exporting Countries
P-Units	Performance Units
Plan	Amended and Restated 2013 Rowan Companies plc Incentive Plan, dated May 25, 2017

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Abbreviation/Acronym	Definition
RCI	Rowan Companies Inc., a subsidiary of the Company
Retiree Medical Plan	Retiree Life & Medical Supplemental Plan of Rowan Companies, Inc.
Rowan plc	Rowan Companies plc
Rowan SERP	Restoration Plan of Rowan Companies, Inc.
RSAs	Restricted Share Awards
RSUs	Restricted Share Units
SARs	Share Appreciation Rights
Saudi Aramco	Saudi Arabian Oil Company
SEC	The United States Securities and Exchange Commission
SEMS	Safety and environmental management system
Senior Notes	The 2019 Notes, 2022 Notes, 2024 Notes, 2025 Notes, 2042 Notes and 2044 Notes, collectively
Subject Notes	The 2017 Notes, 2019 Notes, 2022 Notes and the 2024 Notes, collectively
Transaction	The transactions contemplated by the Transaction Agreement, pursuant to which each of the issued and outstanding Class A ordinary shares of the Company will be exchanged for 2.750 Class A ordinary shares of Ensco pursuant to a court-sanctioned scheme of arrangement under Part 26 of the U.K. Companies Act 2006
Transaction Agreement	The agreement, dated October 7, 2018, by and between the Company and Ensco, pursuant to which the Company and Ensco will effect a "merger-of-equals" transaction
TSR	Total Shareholder Return
U.K.	United Kingdom
U.S.	United States
U.S. Tax Act	2017 Tax Cuts and Jobs Act
UK Bribery Act	U.K. Bribery Act 2010
US GAAP	Accounting principles generally accepted in the United States of America
US GOM	United States Gulf of Mexico
USD	U.S. Dollar
WTI	West Texas Intermediate

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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 NYSE. The terms “Rowan,” “Rowan plc,” “Company,” “we,” “us” and “our” are used to refer to Rowan plc and its consolidated subsidiaries, unless the context otherwise requires. Intercompany balances and transactions have been eliminated in consolidation.

We are a global provider of offshore contract drilling services to the oil and gas industry, with a focus on ultra-deepwater drillships and high-specification and premium jack-up rigs. Many of our high specification jack-up rigs are also rated for operating in harsh environments. Our fleet operates worldwide, including the US GOM, Mexico, Central and South America, the U.K. and Norwegian sectors of the North Sea, the Middle East and the Mediterranean Sea. We currently operate in three segments: Deepwater, Jack-ups and ARO, our 50/50 joint venture with Saudi Aramco. The Deepwater segment includes four ultra-deepwater drillships. The Jack-ups segment is composed of 21 self-elevating jack-up rigs and includes the impact of the various arrangements with ARO (see Note 4 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report for more information. The information discussed therein is incorporated by reference into this Part I, Item 1.) ARO currently owns a fleet of seven self-elevating jack-up rigs for operation in the Arabian Gulf for Saudi Aramco. ARO has plans to order up to 20 new jack-up rigs over the next 10 years.

As of February 13, 2019, the date of our most recent Fleet Status Report, two of our four drillships were contracted in the US GOM, one was contracted in Mexico and the remaining drillship was marketed without a contract in the US GOM. For our jack-up fleet, we had four rigs under contract in the North Sea, one rig under contract in the Mediterranean Sea, three under contract in Central and South America and two under contract in the US GOM. In the Middle East, we had nine jack-ups leased to ARO to fulfill nine, three-year contracts between Saudi Aramco and ARO, two of which are expected to commence in the first half of 2019. Additionally, we own two jack-up rigs which are 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. Rigs leased to ARO will be through bareboat charter agreements whereby substantially all operating costs will be borne by ARO. ARO will contract with the customer, Saudi Aramco, and directly receive related revenue. For Rowan plc and its consolidated subsidiaries, intercompany balances and transactions have been eliminated in consolidation.

Proposed Combination of Rowan Companies plc and Ensco plc

On October 7, 2018, the Company entered into a Transaction Agreement with Ensco, to effect a “merger-of-equals” transaction. The Transaction Agreement was amended as of January 28, 2019, pursuant to a Deed of Amendment No. 1 to a Transaction Agreement (the “Amendment”). In the Transaction Agreement, as amended, each of the issued and outstanding Class A ordinary shares of the Company will be exchanged (the “Transaction”) for 2.750 Class A ordinary shares of Ensco, each with a nominal value of $0.10 per share. The Transaction is being implemented by means of a court-sanctioned scheme of arrangement (the “Scheme”) under Part 26 of the U.K. Companies Act 2006 (provided that the parties reserve the right under the Transaction Agreement to effect the acquisition by way of a contractual takeover offer as defined in section 974 of the U.K. Companies Act 2006 in certain circumstances). The resulting new combined company will be renamed and trade under a new ticker symbol on the New York Stock Exchange.

The completion of the Transaction is subject to various closing conditions, including, among other things, (i) the sanction of a court-sanctioned scheme of arrangement by the High Court of Justice of England and Wales, (ii) the receipt of the required regulatory approval or elapse of the review period with respect thereto in the Kingdom of Saudi Arabia, (iii) the absence of legal restraints prohibiting or restraining the Transaction and (iv) the absence of any law or order reasonably expected to result in the dissolution of ARO, the sale or disposition of the Company's interest in ARO, or the forfeiture or nationalization of the Company's interest in ARO or ARO's assets. The Transaction is expected to close during the first half of 2019.

The Transaction Agreement contains certain termination rights for both Rowan and Ensco including, among other things: (i) by Rowan or Ensco, if the other party breaches or fails to perform any of its representations, warranties or covenants in the Transaction Agreement that cannot be or is not cured in accordance with the terms of the Transaction Agreement and such breach constitutes a "material adverse effect", (ii) by Rowan, in the event that the board of directors of Ensco makes an Adverse Recommendation Change (as defined in the Transaction Agreement) or upon any "willful breach" by Ensco of the non-solicitation covenant and (iii) by Ensco, in the event that the board of directors of Rowan makes an Adverse Recommendation Change (as defined in the

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Transaction Agreement) or upon any “willful breach” by Rowan of the non-solicitation covenant. If the Transaction Agreement is terminated in accordance with clause (i), (ii) or (iii), then Rowan or Ensco, as the applicable terminating party, shall be required to pay the other a termination fee of $24.0 million (the “Termination Fee”).

Neither Rowan nor Ensco is permitted, among other things, to solicit, initiate or knowingly facilitate or knowingly encourage any inquiries regarding, or the making of any proposal or offer that constitutes, or could reasonably be expected to lead to, a takeover proposal or engage in or participate in any discussions or negotiations regarding any takeover proposal.

The Transaction Agreement contains customary representations, warranties and covenants for a transaction of this nature. The Transaction Agreement also contains customary mutual pre-closing covenants, including the obligation of Rowan and Ensco to conduct their respective businesses in the ordinary course of practice consistent with past practice and to refrain from taking certain specified actions without the consent of the other party.

The foregoing description of the Transaction and the Transaction Agreement does not purport to be complete and is subject to, and qualified in its entirety by, the full text of the Transaction Agreement, a copy of which is included in Exhibit 2.1 as filed with the Form 8-K dated October 9, 2018, and the full text of the Deed of Amendment No. 1 to the Transaction Agreement, a copy of which is included as Exhibit 2.1 as filed with the Form 8-K filed January 29, 2019. The Transaction Agreement, as amended, has been referenced to provide investors with information regarding its terms. It is not intended to provide any other factual information about Rowan or Ensco. In particular, the assertions embodied in the representations and warranties contained in the Transaction Agreement are qualified by matters disclosed in certain of Rowan’s and Ensco’s filings with the SEC prior to the date of the Transaction Agreement and by information in confidential Disclosure Schedules provided by each of Rowan and Ensco to the other in connection with the signing of the Transaction Agreement. These confidential Disclosure Schedules contain information that modifies, qualifies and creates exceptions to the representations and warranties and certain covenants set forth in the Transaction Agreement. The representations, warranties and covenants are also subject to materiality qualifications contained in the Transaction Agreement that may differ from what may be viewed as material by investors. Moreover, certain representations and warranties in the Transaction Agreement were used for the purposes of allocating risk between Rowan and Ensco rather than establishing matters as facts. Accordingly, the representations and warranties in the Transaction Agreement should not be relied on as characterizations of the actual state of facts about Rowan or Ensco. The Transaction Agreement should not be read alone, but should instead be read in conjunction with other information regarding the Company that is or will be contained in, or incorporated by reference into, the Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and other documents that the Company files or furnishes with the SEC.

ARO Joint Venture

On November 21, 2016, Rowan and Saudi Aramco, through their subsidiaries, entered into a Shareholders’ Agreement to create a 50/50 joint venture to own, manage and operate offshore drilling units in Saudi Arabia. The new entity, ARO, was formed in May 2017 and commenced operations on October 17, 2017. For additional information see "ARO Joint Venture" in Note 1, Note 4 and Note 15 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report. The information discussed therein is incorporated by reference into this Part I, Item 1.

Drilling Fleet

We believe our fleet of ultra-deepwater drillships and high-specification and premium jack-ups is well positioned to serve the worldwide market. Many of our high specification jack-ups are also rated for operating in harsh environments. As of February 13, 2019, our drilling fleet consists of the following:

- Four ultra-deepwater drillships;
- Fifteen high-specification jack-up rigs; and
- Six premium jack-up 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 and the term “high-specification” to describe premium jack-ups that also have a hook-load capacity of at least two million pounds.

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 using their onboard propulsion and position reference systems. Drillships have greater variable 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 are designed to prevent environmental and safety issues as well as significantly reduce non-productive time associated with repair and maintenance. In addition, each drillship is equipped with an active-heave compensating crane for deployment of subsea equipment simultaneous to drilling station operations. The sum total of these and other advanced features make the drillships very attractive to our customers.

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, location and outfitting. All of our high-specification rigs are equipped with or can readily accommodate the high-pressure circulation and pressure control equipment that is 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 until they penetrate the ocean floor. After the legs are securely set, 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 in water depths to 435 feet in harsh environments such as the North Sea depending on location and outfitting. 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.

Three of our four Super Gorilla class rigs can be equipped for simultaneous drilling and production operations. They can operate in up to 450 feet of water in harsh environments such as the North Sea depending on location and outfitting. The Bob Palmer, our fourth Super Gorilla class rig, is an enhanced version of the Super Gorilla class jack-up designated as Super Gorilla XL. The Bob Palmer can operate in water depths up to 550 feet in benign environments like the US GOM and the Middle East or in water depths up to 450 feet in harsh environments such as the North Sea depending on location and outfitting.

Our three 240C class rigs were designed for HPHT drilling in water depths up to 400 feet in benign environments, depending on rig size, location and outfitting, and are equipped with a hook-load capacity of 2.5 million pounds. The rigs are also capable of operating in harsh environments at reduced water depths compared to their benign environment ratings.

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.

In January 2018, we purchased two Super 116E class rigs. These are premium rigs capable of drilling in water depths up to 350 feet and are equipped with a hook-load capacity of 1.5 million pounds.

Our four remaining 116C class rigs are premium rigs capable of operating in water depths up to 300 feet in benign environments. One of these rigs is cold-stacked.

Our one remaining Gorilla class rig, the Rowan Gorilla IV, was designed as a heavier-duty class of jack-up rig capable of operating in water depths to 450 feet in benign environments. This rig is cold-stacked.

We sold the Scooter Yeargain and Hank Boswell to ARO in October 2018. This follows the previous sale of one premium and two high-specification jack-ups in October 2017 to ARO (see Note 1 and Note 15 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report).

See Part I, Item 2, "Properties" of this Annual Report for additional information regarding our fleet.

Our operations are subject to many uncertainties and hazards. See Part I, Item 1A, "Risk Factors", of this Annual Report 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 multiple years. Well-to-well contracts are typically cancellable by either party upon completion of drilling a well. 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, 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 or, in some cases, predetermined rates. Some of our drilling contracts provide for separate lump-sum payments for rig mobilization and demobilization. We record certain lump-sum fees and related expenses over the expected recognition period. We recognize reimbursement of certain costs as revenue and expenses at the time they are incurred. Our contracts for work generally provide for payment in USD 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” in this Part I, Item 1 of this Annual Report and in “Risk Factors” included in Part I, Item 1A of this Annual Report include the global economic climate, the price of oil and gas which can affect our customers' drilling budgets, over- supply of drilling units, location and availability of competitive equipment, the suitability of equipment for the project, comparative operating cost of the equipment, cost of securing competent drilling personnel and other competitive factors. Profitability may also depend on receiving adequate compensation for the cost of moving equipment to drilling locations and capital investment needed for contract specific requirements.

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 "warm-stack" rigs to reduce costs during extended periods between contracts. We currently have one ultra-deepwater drillship warm stacked. We have also cold-stacked certain of our idle older rigs to further reduce costs and have sold the following six such rigs over a period beginning in 2015: the Rowan Juneau, Rowan Alaska, Rowan Louisiana, Rowan Gorilla II, Rowan Gorilla III and Cecil Provine. All were sold under agreements that prohibit or limit their future use as drilling units.

Our contract backlog was estimated to be approximately $634.9 million at February 13, 2019, up from approximately $456.2 million at February 13, 2018. Our backlog excludes ARO's revenue, but includes bareboat charter and related revenue for jack-ups leased to ARO. See "Management’s Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources" in Part II, Item 7 of this Annual Report for further information with respect to our backlog.

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, local content requirements and reputation.

In the jack-up drilling market, we compete with numerous offshore drilling contractors that together have 451 marketed jack-up rigs worldwide as of February 13, 2019, with an additional 77 units that are under construction or on order. (We define marketed rigs as all delivered rigs that are not cold-stacked.) We estimate that 79 marketed jack-ups, or 18 percent of the world’s marketed jack-up fleet, are high-specification, including Rowan's 14 marketed high-specification rigs.

At February 13, 2019, there were 196 marketed floaters (drillships and semi-submersibles) worldwide, with an additional estimated 31units that are under construction or on order. We estimate that 103 of these marketed floaters, or approximately 53 percent of the world’s marketed fleet, are capable of drilling in water depths of 10,000 feet or more, but only an estimated 36 floaters, or approximately 18 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 many deepwater customers.

A significant contributing factor to the softness in the offshore drilling market has been the influx of 263 newbuild jack-ups and 165 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 support intense competition, putting downward pressure on day rates and utilization percentage in most regions and sectors. Of the approximately 77 jack-up rigs under construction worldwide scheduled for delivery through 2021 (25% of the currently utilized jack-up fleet of approximately 311 rigs), approximately 37 are considered high-specification (47% of the delivered and marketed high-specification fleet). Currently, there are approximately 44 competitive newbuild jack-up rigs scheduled for delivery during the remainder of 2019, and to our knowledge only one has a contract in place. There are approximately 31 floaters under construction worldwide for delivery through 2021 (25% of the currently utilized floater fleet of approximately 125 rigs). Following the negotiated delivery delays on several units into future years, there are approximately 16 competitive newbuild floaters scheduled for delivery during the remainder of 2019 and, to

our knowledge, only one has a contract.
Based on the number of rigs as tabulated by IHS-Petrodata, we are the seventh largest offshore drilling contractor in the world and the sixth largest jack-up rig contractor. Based on market capitalization as of February 13, 2019, we are the third largest publicly traded pure play offshore driller. 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 government-owned or government-controlled energy companies. See "Management's

Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of this Annual Report 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 those relating to environmental protection and pollution control. In addition, governmental regulations concerning licensing and permitting, 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.

We could become liable for damages resulting from pollution which could materially affect our financial position, results of operations and liquidity. In many of our drilling contracts, we are indemnified for pollution, well damage and environmental damage, except in certain cases of pollution emanating from our drilling rigs. This indemnity includes costs associated with regaining control of a wild well, removal and disposal of pollutants, environmental remediation and claims by third parties for damages. However, such contractual indemnification provisions may not adequately protect us for several reasons such as (i) the contractual indemnity provisions may require us to assume certain types or amounts of the liability; (ii) our customers may not have the financial resources necessary to honor the contractual indemnity provisions; or (iii) the contractual indemnity provisions may be unenforceable under applicable law.

Our customers often require us to assume responsibility for pollution damages when we are at fault. We seek to limit our liability to certain types of exposures such as claims by third parties. We may also seek to limit our liability to a non-material monetary amount or an amount within the limits of our available insurance coverage. For example, a contract may provide that we will assume the first $50 million of costs related to an incident resulting in wellbore pollution due to our negligence, with the customer assuming responsibility for costs in excess of that amount. We can provide no assurance that we will be able to negotiate indemnities and/or limitation of liability provisions 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 where we are liable for all or a portion of such event, the impact on our financial position, results of 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, if available, 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.

The jurisdictions in which we operate have various regulations and requirements with which we must comply. For example, pursuant to the U.S. Clean Water Act, a National Pollutant Discharge Elimination ("NPDES") permit is required for discharges into the US GOM. The permit holder is the designated responsible party for any environmental impacts that 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 or in the event of non-compliance with permit requirements. We operate in accordance with NPDES permit standards regardless of the holder.

Pursuant to the U.K. Offshore Directive, we are required to have an approved Oil Pollution Emergency Plan ("OPEP") for each drilling unit 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 IMO MARPOL 73/78, 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 in conjunction with the rig's emergency response manual 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. For operations anywhere in the world including in the U.S., our SOPEPs are subject to review and approval by Flag State, or a Recognized Organization acting on behalf of Flag State.

As the designated responsible party, an 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 drilling units to mitigate the impact of an incident until an emergency spill response organization can 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 in the U.S. specializes in helping industries prevent and clean up oil and other hydrocarbon spills. Our provider has represented it holds all necessary licenses, certifications and permits to respond to environmental emergencies in the

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US GOM and maintains contracts with other response resources and organizations outside the US GOM. We believe we have adequate equipment and third-party resources available to us to respond to an emergency spill; however, we can provide no assurance that adequate resources will be available.

We are actively involved in various industry-led initiatives and work groups, including but not limited to those of the International Maritime Organization (a specialized agency of the United Nations), United States Coast Guard National Offshore Safety Advisory Committee, American Petroleum Institute, the International Association of Drilling Contractors, the Oil Companies International Marine Forum, the Center for Offshore Safety and the British Rig Owners Association, which are intended to improve safety and protection of the environment.

Oil and gas operations in the US GOM and in many of the other jurisdictions 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 SEMS. Any serious oil and gas industry related events heighten 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 may 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.

Regulatory compliance has and may continue to materially impact our capital expenditures and earnings, particularly in the event of an environmental incident. Given the state-of-the-art design of our drillships and high specification nature of the majority of our jack-up fleet, we believe we are well positioned competitively to our peers to be able to comply with current and future governmental regulations.

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 upon renewal.

Employees

At December 31, 2018, we had approximately 3,300 employees worldwide, compared to approximately 2,800 and 2,900 at December 31, 2017 and 2016, respectively, and approximately 530 independent contractors. Certain of our employees and contractors in various regions, 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 2018, Saudi Aramco, Anadarko, ARO Drilling, and BP Trinidad and Tobago accounted for 28%, 14%, 14%, and 10%, respectively, of consolidated revenue. Saudi Aramco and BP Trinidad and Tobago revenue was derived from our Jack-ups segment, Anadarko revenue was derived from our Deepwater segment and ARO Drilling revenue was derived from our Jack-ups segment as well as revenue for transition services provided to ARO which is included in

Unallocated and other.

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

ITEM 1A. RISK FACTORS

There are numerous factors that affect our business and operating results, many of which are beyond our control. The following is a description of significant factors that might cause our future operating results to differ materially from those currently expected. The risks described below are not the only risks facing our Company.

Our business depends on the level of activity in the offshore oil and gas industry, which is significantly affected by declines in oil or gas prices and reduced demand for oil and gas products.

Our business 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, 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 their ability to raise capital;
- the willingness and ability of the 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, interest rates 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 of assets or workforce and/or confiscation of assets;
- worldwide tax policies and treaties;
- political and military conflicts in oil-producing areas and the effects of terrorism;
- increased supply of oil and gas from onshore development and relative cost of offshore drilling versus onshore oil and gas production;
- the development and exploitation of alternative fuels and energy sources including the growing demand, often government-mandated, for electric powered vehicles; 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 declines in oil or gas prices or the failure of oil or gas prices to increase, a global recession, 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 weak 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 February 13, 2019, we had two jack-up drilling units that are currently cold-stacked; seven with contract terms ending in 2019; two with contract terms ending in 2020; one with a contract term ending in 2021; and nine leased to ARO with leases ending in 2021. Additionally, one of our four drillships is without a contract; two have a contract ending in 2019 and one has a contract ending in 2020. Given current market conditions, future demand for offshore drilling units may continue at low day rate levels, possibly 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 downturn in the drilling sector, the industry experienced a significant increase in construction activity. The resulting increase in supply of newbuild drilling units, combined with the decrease in demand for offshore drilling services, has led to an oversupply of drilling units and levels of utilization and day rates that are expected to remain weak for some time. According to industry sources, there were 451 marketed jack-up rigs worldwide as of February 13, 2019, an additional 77 units that are under construction or on order and 196 marketed floaters (drillships and semi-submersible) worldwide, with an additional 31 units that are under construction or on order. A decline in utilization and day rates would further impact our revenue and profitability.

A 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 $34 million in 2016, or approximately 0.5% 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 the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report 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 material impact on our business.

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

Our operations are diversified geographically although we have a concentrated presence in certain locations. 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 restrictions, 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, especially in areas of concentrated presence (see Note 14 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report).

Many countries have regulations or policies requiring or rewarding the participation of local companies and individuals in 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 co-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 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 the jurisdictions in which we operate 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 certain jurisdictions 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 revenue and expenses are transacted in USD, 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. We can provide no assurance that we will be able to convert into USD or utilize such foreign currency holdings due to controls over currency exchange or controls over the repatriation of income or capital. For more information, see “Assets and Liabilities Measured at Fair Value on a Recurring Basis” in Note 8 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report.

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 offshore drilling services and excess rig supply, resulting from a prolonged period of weak oil and gas prices and reduced worldwide drilling activity. These conditions have intensified the competition in the industry and put significant 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, accept less favorable contract terms 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 may experience reduced profitability if our customers terminate or seek to renegotiate our drilling contracts, and our backlog of drilling revenue may not be fully 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 may be canceled 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 may 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 revenue would decline, adversely affecting our financial results.

We must make substantial capital and operating expenditures to 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 capital expenditure requirements. We can provide no assurance that we will have access to adequate or economical sources of capital to fund necessary capital and operating 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 2018, four customers accounted for 56% of our consolidated revenue (Saudi Aramco - 28%; Anadarko - 14%; ARO Drilling - 14%; BP Trinidad and Tobago - 10%). 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, our drilling contracts subject us to counterparty risks. The ability of each of our counterparties to perform its obligations under a contract with us will depend on a number of factors that are beyond our control such as the overall financial condition of the counterparty. Should a significant counterparty fail to honor its obligations under an agreement with us, we could sustain losses, which could have a material adverse effect on our business, financial condition and results of operations.

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 could result in further unexpected, substantial expenditures. 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 material 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 U.S. Bureau of Ocean Energy Management and BSEE, 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.

We may not realize the expected benefits of the ARO joint venture and it may introduce additional risks to our business.

In November 2016, Rowan and Saudi Aramco announced plans to form a 50/50 joint venture with Rowan and Saudi Aramco each selling existing drilling units and contributing capital as the foundation of the new company. The new entity, ARO, commenced operations on October 17, 2017, and is expected to add up to 20 newbuild jack-up rigs to its fleet over ten years commencing as early as 2021. There can be no assurance that the new jack-up rigs will begin operations as anticipated or we will realize the

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expected return on our investment. We may also experience difficulty jointly managing the venture, and integrating our existing employees, business systems, technologies and services with those of Saudi Aramco in order to operate the joint venture efficiently. Further, in the event ARO has insufficient cash from operations or is unable to obtain third party financing, we may periodically be required to make additional capital contributions to ARO, up to a maximum aggregate contribution of $1.25 billion, which could affect our liquidity position. As a result of these risks, it may take longer than expected for us to realize the expected returns from ARO or such returns may ultimately be less than anticipated. Additionally, if we are unable to make any required contributions, our ownership in ARO could be diluted which could hinder our ability to effectively manage ARO and harm our operating results or financial condition.

Operating through ARO, in which we have a shared interest, may also result in us having less control over many decisions made with respect to projects and internal controls relating to projects. ARO may not apply the same internal controls and internal control reporting that we follow. As a result, internal control issues may arise, which could have a material adverse effect on our financial condition and results of operations. Additionally, in order to establish or preserve our relationship with our joint venture partner, we may agree to risks and contributions of resources that are proportionately greater than the returns we could receive, which could reduce our income and return on our investment in ARO compared to what we may traditionally require in other areas of our business.

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 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 revenue associated with downtime required to implement regulatory requirements.

Oil and gas operations in many of the 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. 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.

Regulation of greenhouse gases and climate change could have a negative impact on our business.

Governments around the world are increasingly focused on enacting laws and regulations regarding climate change and regulation of greenhouse gases. Lawmakers and regulators in the jurisdictions where we operate have proposed or enacted regulations requiring reporting of greenhouse gas emissions and the restriction thereof. In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues and impose reductions of hydrocarbon-based fuels. Laws or regulations incentivizing or mandating the use of alternative energy sources such as wind power and solar energy have also been enacted in certain jurisdictions. Numerous large cities globally and a few countries have mandated conversion from internal combustion engine powered vehicles to electric-powered vehicles and placed restrictions on non-public transportation, thereby reducing future demand for oil which could have a material impact on our business. Laws, regulations, treaties and international agreements related to greenhouse gases and climate change may unfavorably impact our business, our suppliers and our customers, and result in increased compliance costs, operating restrictions and could reduce drilling in the offshore oil and gas industry, all of which would have a material adverse impact on our business.

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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 or necessary supplies 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.

We are subject to tax laws, regulations and treaties in many jurisdictions. 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 income tax cost in excess of currently recorded amounts if our positions are challenged and we are unsuccessful in defending them.

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 have been legislative proposals in the U.S. that attempted 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, or 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 certain undistributed earnings of non-U.K. subsidiaries. If facts and circumstances cause a change in the expectations regarding future tax consequences, the resulting tax impact could have a material effect on the Company's consolidated financial statements.

On December 22, 2017, the U.S. government enacted tax legislation commonly referred to as the U.S. Tax Act. The U.S. Tax Act significantly changes U.S. corporate income tax laws including but not limited to (i) reducing the U.S. corporate income tax rate from 35% to 21% starting January 1, 2018, (ii) requiring a one-time transition tax on mandatory deemed repatriation of certain unremitted non-U.S. earnings as of December 31, 2017, (iii) changing how non-U.S. subsidiaries are taxed in the U.S. as of January 1, 2017, (iv) eliminating the carryback abilities and establishing an 80% limitation on the annual utilization of net operating losses after December 31, 2017, (v) establishing new limitations on interest deductions as of January 1, 2018, and (vi) requiring additional U.S. tax on certain payments by U.S. subsidiaries to non-U.S. subsidiaries if such payments are subject to reduced rates of U.S. withholding tax under a treaty after December 31, 2017. In 2017, the Company applied the guidance in accordance with the SEC Staff Accounting Bulletin No. 118, Income Tax Accounting Implications of the Tax Cuts and Jobs Act (SAB 118) that allowed provisional estimates for the tax effects of the U.S. Tax Act. During 2018, the accounting for this matter has been finalized. For more information see Note 13 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report.

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. We are also 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. Finally, our business may be impacted by changes to trade policies or economic sanctions in places where we conduct or could conduct business.

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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 9.3% of our available rig days in 2018. 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.

Our cost reduction initiatives might have unintended consequences and could negatively impact our business.

In response to changes in our industry, we have implemented and are considering implementing initiatives to reduce costs and improve operational efficiencies. If we do not successfully manage these cost reduction activities, the expected efficiencies and benefits might be delayed or may not be realized, and our operations and business could be disrupted. In addition, there is the risk that such measures could negatively impact our business by reducing our ability to respond to a significant increase in demand for our services, erroneously omitting operational or financial controls, reducing our pool of talent, adversely affecting employee morale, distracting management, or slowing improvements in our services, any of which could adversely affect our business, financial condition and results of operations.

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. 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 have material adverse affects on our financial position, results of operations and cash flows.

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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 the parties 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 may receive from operators varies from contract to contract based on market conditions and customer requirements existing when the contract was negotiated, and recovery is dependent on the customer's financial condition. 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, particularly in cases of gross negligence, willful misconduct, punitive damages or punitive fines and/or penalties. The failure of a customer 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.

Our information technology 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 or customers, to conduct our business and operations. In addition, we rely on our employees to vigilantly follow the Company's policies with respect to the use of these systems. Cybersecurity risks and threats to such systems have been encountered and continue to grow and may be difficult to anticipate, prevent, identify or mitigate. If any of our, our service providers' or our customers' security systems prove to be insufficient or our employees are not sufficiently vigilant, we could be adversely affected by having our business and financial systems compromised or made inoperable, our companies', employees', vendors' or customers' confidential or proprietary information altered, lost or stolen, or our (or our customers') business operations, financial systems 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.

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 FCPA, the UK Bribery Act and similar laws in other jurisdictions generally prohibit companies and their intermediaries from making improper payments to governmental 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 jurisdictions, including prohibition of our participation in or curtailment of business operations in those jurisdictions and the seizure of drilling units or other assets.

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. The recent prolonged industry downturn may further reduce the number of qualified personnel available in the future. 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

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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.

Downgrades in our credit ratings may affect our ability to access the credit and debt capital markets.

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 economic environment, concerns about the offshore drilling industry and our credit ratings may restrict our access to the credit and debt capital markets in the future and increase the cost of such indebtedness. As a result, 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.

Certain credit rating agencies have downgraded our credit ratings below investment grade and may further downgrade our credit ratings at any time. A further downgrade in our ratings 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;
- 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.

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.

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 various regions 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 revenue or limit our operations.

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 revenue and adversely impact our operations.

Our reliance on third-party suppliers, manufacturers and service providers to secure equipment used in our drilling operations could expose 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 revenue by resulting in uncompensated downtime, reduced day rates or the cancellation or termination of contracts, or increase our operating costs. Our reliance on one or more of these third-party suppliers could further exacerbate such issues.

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.

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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 shareholder approval requirements required under U.K. law, we may have less flexibility than a Delaware corporation with respect to certain aspects of capital management.

Unlike most U.S. state corporate law, English law provides that a board of directors may generally only allot shares with the prior authorization of shareholders, which such authorization may only extend for a maximum period of five years. English law also generally provides shareholders preemptive rights when new shares are issued for cash unless such rights are waived by the shareholders.

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, which approval may only extend for a maximum period of five years.

At our 2018 annual general meeting of shareholders, our Board was authorized to allot a certain amount of shares, exclude certain preemptive rights in shares for cash offerings and effect off market purchases, in each case without further shareholder approval. However, these authorizations expire in May 2019. As such, we will be unable to issue new shares or repurchase shares unless and until we receive renewed shareholder approval. In addition, even if approved by shareholders, our ability to issue and repurchase shares may be substantially more restricted than a U.S. company.

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

Under English law, a public company may only declare dividends and make other distributions to shareholders (such as a share buyback) if the company has sufficient distributable reserves and meets certain net asset requirements. If we do not have sufficient distributable reserves or cannot meet the net asset requirements, we may be limited in our ability to timely pay dividends and effect other distributions to our shareholders.

Our business could be negatively affected by the actions of activist shareholders.

Certain of our shareholders may from time to time advance shareholder proposals or otherwise attempt to effect changes or acquire control over our business. Activist campaigns that contest or conflict with our strategic direction could have an adverse effect on our results of operations and financial condition. Responding to proxy contests and other actions by activist shareholders could disrupt our operations, be costly and time-consuming, and divert the attention of our Board and senior management from the pursuit of business strategies. In addition, perceived uncertainties as to our future direction may lead to the perception of a change in the direction of the business, instability or lack of continuity, which may be exploited by our competitors, cause customer and employee concerns, result in the loss of potential business opportunities, or make it more difficult to attract and retain qualified personnel. Such perceived uncertainties could negatively affect the trading price and volatility of our common stock.

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The U.K.’s referendum to exit from the E.U. will have uncertain effects and could adversely impact our business, results of operations and financial condition.

On June 23, 2016, the U.K. voted to exit from the E.U. (commonly referred to as Brexit). The terms of Brexit and the resulting U.K./E.U. relationship are uncertain for companies doing business both in the U.K. and the overall global economy. In addition, our business and operations may be impacted by any subsequent vote in Scotland to seek independence from the U.K. Risks related to Brexit that we may encounter include:

- adverse impact on macroeconomic growth and oil and gas demand;
- continued volatility in currencies including the British pound and USD that may impact our financial results;
- reduced demand for our services in the U.K. and globally;
- increased costs of doing business in the U.K. and in the North Sea;
- uncertain impact of regulatory changes arising from an exit from the E.U.;
- increased regulatory costs and challenges for operating our business in the North Sea;
- volatile capital and debt markets, and access to other sources of capital;
- risks related to our global tax structure and the tax treaties upon which we rely;
- business uncertainty resulting from prolonged political negotiations; and
- uncertain stability of the E.U. and global economy if other countries exit the E.U.

We and Ensco will be subject to various uncertainties and contractual restrictions while the Transaction is pending that could adversely affect each party's business and operations.

In connection with the proposed Transaction, it is possible that some customers, suppliers and other persons with whom we or Ensco have business relationships may delay or defer certain business decisions, or might decide to seek to terminate, change or renegotiate their relationship with us or Ensco as a result of the Transaction, which could negatively affect our or Ensco’s respective financial positions, operating results or cash flows, as well as the market price of our shares and Ensco’s shares, regardless of whether the Transaction is completed.

Under the terms of the Transaction Agreement, we and Ensco are subject to certain restrictions on the conduct of our businesses prior to completing the Transaction, which may adversely affect our and Ensco’s ability to execute certain business strategies. Such limitations could negatively affect each party’s businesses and operations prior to the completion of the Transaction. Furthermore, the process of planning to integrate two businesses and organizations for the post-transaction period may divert management’s attention and resources and could ultimately have an adverse effect on each party. These uncertainties could cause customers, suppliers and others that deal with us or Ensco to seek to change existing business relationships with such party, which in turn could have an adverse effect on the combined company’s ability to realize the anticipated benefits of the Transaction.

We or Ensco may have difficulty attracting, motivating and retaining executives and other employees in light of the Transaction.

Uncertainty about the effect of the Transaction on our employees or Ensco’s employees may impair the companies' ability to attract, retain and motivate personnel until the Transaction is completed. Employee retention may be particularly challenging during the pendency of the Transaction, as employees may feel uncertain about their future roles with the combined organization. In addition, we or Ensco may have to provide additional compensation in order to retain employees. If our employees or Ensco’s employees depart because of issues relating to the uncertainty and difficulty of integration or a desire not to become employees of the combined company, the combined company’s ability to realize the anticipated benefits of the Transaction could be adversely affected.

The Transaction is subject to conditions, including certain conditions that may not be satisfied, and may not be completed on a timely basis, if at all. Failure to complete the Transaction, or significant delays in completing the Transaction, could negatively affect the trading price of our shares and our future business and financial results.

The completion of the Transaction is subject to a number of conditions beyond our and Ensco’s control that may prevent, delay or otherwise materially adversely affect its completion, including the approval of governmental agencies. Neither we nor Ensco can predict whether and when these other conditions will be satisfied.

If the Transaction is not completed, we will be subject to several risks and consequences, including the following:

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- certain damages for which we may be liable to Ensco under the terms and conditions of the Transaction Agreement;
- negative reactions from the financial markets, including declines in the price of our shares due to the fact that current prices may reflect a market assumption that the Transaction will be completed;
- certain significant costs relating to the Transaction, including, in certain circumstances, the payment by us of $15 million for Ensco’s expenses and a termination fee payable by us of $24 million less any previous expense reimbursements; and
- diverted attention of our management to the Transaction rather than our own operations and pursuit of other opportunities that could have been beneficial to us.

We and Ensco will incur substantial transaction fees and costs in connection with the Transaction.

We and Ensco expect to incur a number of non-recurring transaction-related costs associated with completing the Transaction, combining the operations of the two organizations and achieving desired synergies. These fees and costs will be substantial. Non-recurring transaction costs include, but are not limited to, fees paid to legal, financial, accounting and other advisors, retention, severance and other integration-related costs, filing fees and printing costs. Additional unanticipated costs may be incurred in the integration of our business and Ensco’s business. There can be no assurance that the elimination of certain duplicative costs, as well as the realization of other efficiencies related to the integration of the two businesses, will offset the incremental transaction-related costs over time. Thus, any net benefit may not be achieved in the near term, the long term or at all.

If completed, the Transaction may not achieve its intended results, and we and Ensco may be unable to successfully integrate our operations. Failure to successfully combine our business and Ensco’s business in the expected time frame may adversely affect the future results of the combined organization and, consequently, the value of Ensco's shares that our shareholders receive as the Transaction consideration.

We and Ensco entered into the Transaction Agreement with the expectation that the Transaction will result in various benefits, including, among other things, expanding our geographic presence and customer base and creating synergies. Achieving the anticipated benefits of the Transaction is subject to a number of uncertainties, including whether the businesses of us and Ensco can be integrated in an efficient and effective manner. Because our shares are being exchanged for Ensco's shares in the Transaction, our stock price may be adversely affected by a decline in Ensco's stock price and any adverse developments in Ensco's business, either of which may result from a variety of factors beyond our control.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees, the disruption of each company's ongoing businesses, processes and systems or inconsistencies in standards, controls, procedures, practices, policies and compensation arrangements, any of which could adversely affect the combined company's ability to achieve the anticipated benefits of the Transaction. The combined company's results of operations could also be adversely affected by any issues attributable to either company's operations that arise or are based on events or actions that occur prior to the completion of the Transaction. The companies may have difficulty addressing possible differences in corporate cultures and management philosophies. The integration process is subject to a number of uncertainties, and no assurance can be given that the anticipated benefits will be realized or, if realized, the timing of their realization. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect the combined company's future business, financial condition, operating results and cash flows.

A downgrade in our or our subsidiaries’ credit ratings following the Transaction could impact the combined entity’s access to capital and cost of doing business.

Following the Transaction, rating agencies may re-evaluate our and our subsidiaries' ratings, and any additional actual or anticipated downgrades in such credit ratings could limit our ability to access credit and capital markets, or to restructure or refinance our indebtedness. As a result of any such downgrades, future financings or refinancings may result in higher borrowing costs and require more restrictive terms and covenants, including obligations to post collateral with third parties, which may further restrict operations and negatively impact liquidity.

Credit rating agencies perform independent analysis when assigning credit ratings. The analysis includes a number of criteria including, but not limited to, business composition, market and operational risks, as well as various financial tests. Credit rating agencies continue to review the criteria for industry sectors and various debt ratings and may make changes to those criteria from time to time. Credit ratings are not recommendations to buy, sell or hold investments in the rated entity. Ratings are subject to revision or withdrawal at any time by the rating agencies, and we cannot assure you that we will maintain our current credit ratings.

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Completion of the Transaction will trigger change of control or other provisions in certain agreements to which we are a party.

The completion of the Transaction will trigger change of control or other provisions in certain agreements to which we are a party. In particular, pursuant to the indenture governing the 2025 Notes, the combined company will be required to make an offer to purchase all of each holder's notes at an amount equal to 101% of the aggregate principal amount of such holder's notes, plus accrued and unpaid interest, if any, if there is a ratings downgrade by both Moody's Investors Service, Inc. ("Moody's") and S&P Global Rating ("S&P") between the public notice of the Transaction and 60 days after the consummation of the Transaction (or any extended period if either Moody's or S&P publicly announces a possible downgrade). As a result, the combined company could be required to repay up to an aggregate $500 million principal amount of senior notes plus approximately $5 million in associated premiums.

In addition, the completion of the Transaction will constitute a change of control under the Existing Credit Facility and the New Credit Facility. As a result, the commitments will be terminated and the outstanding balances under each of the Existing Credit Facility and the New Credit Facility will be accelerated and become due and payable by us in connection with the completion of the Transaction. As of December 31, 2018, we had no outstanding borrowings under either the Existing Credit Facility and the New Credit Facility.

If a governmental authority asserts objections to the Transaction, we and Ensco may be unable to complete the Transaction or, in order to do so, we and Ensco may be required to comply with material restrictions or satisfy material conditions.

The completion of the Transaction is subject to the condition that there is no order, injunction, decree or other legal restraint by a governmental authority in effect restraining, preventing or prohibiting the Transaction contemplated by the Transaction Agreement. If a governmental authority asserts objections to the Transaction, we or Ensco may be required to divest assets or accept other remedies in order to complete the Transaction. There can be no assurance as to the cost, scope or impact of the actions that may be required to address any governmental authority objections to the Transaction. If we or Ensco takes such actions, it could be detrimental to us or to the combined company following the consummation of the Transaction. Furthermore, these actions could have the effect of delaying or preventing completion of the Transaction or imposing additional costs on or limiting the operating results or cash flows of the combined company following the consummation of the Transaction.

In addition, in some circumstances, a third party could initiate a private action under antitrust laws challenging or seeking to enjoin the Transaction, before or after it is completed. We or Ensco may not prevail and may incur significant costs in defending or settling any action under the antitrust laws.

The Transaction may be completed even though material adverse changes subsequent to the announcement of the Transaction, such as industry-wide changes or other events, may occur.

In general, either party can refuse to complete the Transaction if there is a material adverse change affecting the other party. However, some types of changes do not permit either party to refuse to complete the Transaction, even if such changes would have a material adverse effect on either of the parties. For example, a worsening of our or Ensco's financial condition or results of operations due to a decrease in commodity prices or general economic conditions would not give the other party the right to refuse to complete the Transaction. If adverse changes occur that affect either party but the parties are still required to complete the Transaction, our share price, business and financial results after the Transaction may suffer.

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 the U.S., Saudi Arabia (primarily for ARO operations), Norway, Scotland, Trinidad, Bahrain, Dubai, Luxembourg, Malaysia, Singapore, Mexico and Turkey.

Drilling Rigs

Following is the principal drilling equipment owned by Rowan and its location at February 13, 2019.

Rig Name/Type	Class Name	Depth (feet) Water [6]	Drilling [7]	Year of Shipyard Delivery	Location
Ultra-Deepwater Drillships:					
Rowan Renaissance	Gusto MSC P10,000	12,000	40,000	2014	Mexico
Rowan Resolute	Gusto MSC P10,000	12,000	40,000	2014	US GOM
Rowan Reliance	Gusto MSC P10,000	12,000	40,000	2014	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	Turkey
Rowan Stavanger [1]	N-Class	400	35,000	2011	Norway
Rowan Viking [1]	N-Class	435	35,000	2010	Norway
Bob Palmer [1] [5]	Super Gorilla XL	475	35,000	2003	Saudi Arabia
Rowan Gorilla VII [1]	Super Gorilla	400	35,000	2001	U.K.
Rowan Gorilla VI [1]	Super Gorilla	400	35,000	2000	Trinidad
Rowan Gorilla V [1]	Super Gorilla	400	35,000	1998	U.K.
Joe Douglas [1]	240C	350	35,000	2012	Trinidad
Ralph Coffman [1]	240C	350	35,000	2009	US GOM
Rowan Mississippi [1] [5]	240C	375	35,000	2008	Saudi Arabia
Rowan EXL IV [1] [5]	EXL	320	35,000	2011	Saudi Arabia
Rowan EXL III [1]	EXL	350	35,000	2010	US GOM
Rowan EXL II [1]	EXL	350	35,000	2010	Trinidad
Rowan EXL I [1] [5]	EXL	350	35,000	2010	Saudi Arabia
Bess Brants [2] [4] [5]	Super 116E	350	30,000	2013	Bahrain
Earnest Dees [2] [4] [5]	Super 116E	350	30,000	2013	Bahrain
Rowan California [2][3]	116C	300	25,000	1983	Bahrain
Arch Rowan [2] [5]	116C	300	25,000	1981	Saudi Arabia
Charles Rowan [2] [5]	116C	300	25,000	1981	Saudi Arabia
Rowan Middletown [2] [5]	116C	300	25,000	1980	Saudi Arabia
Rowan Gorilla IV [1] [3]	Gorilla	450	30,000	1986	US GOM

(1) High-specification jack-up, which is defined as premium rigs that also have a hook-load capacity of at least two million pounds.

(2) Premium jack-up, which is defined as an independent leg, cantilevered rig capable of operating in water depths of 300 feet or more.

(3) Currently cold-stacked.

(4) Purchased in January 2018 and not yet placed in service.

(5) Leased to ARO

(6) Water depths are the maximum "rated" depths as currently outfitted.

(7) Maximum estimated drilling depth, subject to well characteristics and rig outfitting.

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ITEM 3. LEGAL PROCEEDINGS

We are involved in various routine legal proceedings incidental to our businesses and vigorously defend our position in all such matters. Although the outcome of such proceedings cannot be predicted with certainty, we believe there are no known contingencies, claims or lawsuits that will have a material adverse effect on our financial position, results of operations or cash flows.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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”.

On February 21, 2019, there were 82 shareholders of record. Many of our shareholders hold their shares in "street name" by a nominee of Depository Trust Company, which is a single shareholder of record.

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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, 2018, assuming reinvestment of dividends.

	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018
Rowan	100.00	66.67	49.42	55.08	45.66	24.46
S&P 500 Index	100.00	113.69	115.26	129.05	157.22	150.33
Dow Jones US Oil Equipment & Services Index	100.00	82.78	64.17	81.70	68.05	39.22

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Issuer Purchases of Equity Securities

The following table presents information with respect to acquisitions of our shares for the fourth quarter of 2018:

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)
October 1 - 31, 2018	348	$ 18.68	—	$ —
November 1 - 30, 2018	37	$ 16.05	—	$ —
December 1 - 31, 2018	141,443	$ 8.97	—	$ —
Total	141,828	$ 8.99	—	

(1) The total number of shares acquired includes shares acquired from employees by an affiliated EBT in satisfaction of tax withholding requirements. 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 2018.

(2) The ability to make share repurchases is subject to the discretion of our Board and the limitations set forth in the U.K. Companies Act of 2006, which generally provides that share repurchases may only be made out of distributable reserves. At our 2018 general meeting of shareholders on May 24, 2018, our shareholders approved new repurchase agreements and counterparties, which approval will remain valid until May of 2023. Our Board has authority to commence or suspend share repurchase programs from time to time without prior notice pursuant to these approved repurchase agreements. There are no share repurchase programs outstanding at December 31, 2018.

For information concerning our shares to be issued in connection with equity compensation plans, see Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters in Part III, Item 12, of this Annual Report.

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ITEM 6. SELECTED FINANCIAL DATA

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

	2018	2017	2016	2015	2014
	(Dollars in millions, except per share amounts)				
Operations					
Revenue	$824.8	$1,282.8	$1,843.2	$2,137.0	$1,824.4
Costs and expenses:					
Direct operating costs (excluding items shown below)	682.7	685.0	779.7	980.2	982.8
Depreciation and amortization	388.9	403.7	402.9	391.4	322.6
Selling, general and administrative	96.1	104.6	102.2	114.3	125.1
Gain on sale of assets to unconsolidated subsidiary (1)	(65.8)	(157.4)	—	—	—
(Gain) loss on disposals of property and equipment	12.1	9.4	8.7	(7.7)	(1.7)
Gain on litigation settlement (2)	—	—	—	—	(20.9)
Merger and related costs	8.9	—	—	—	—
Material charges and other operating items (3)	—	—	32.9	337.3	574.0
Total costs and expenses	1,122.9	1,045.3	1,326.4	1,815.5	1,981.9
Equity in earnings of unconsolidated subsidiary	10.3	0.9	—	—	—
Income (loss) from operations	(287.8)	238.4	516.8	321.5	(157.5)
Other (expense) — net (4)	(111.2)	(139.1)	(191.2)	(163.8)	(112.1)
Income (loss) from continuing operations before income taxes	(399.0)	99.3	325.6	157.7	(269.6)
Provision (benefit) for income taxes	(51.6)	26.6	5.0	64.4	(150.7)
Income (loss) from continuing operations	(347.4)	72.7	320.6	93.3	(118.9)
Discontinued operations, net of taxes (5)	—	—	—	—	4.0
Net income (loss)	$(347.4)	$72.7	$320.6	$93.3	$(114.9)
Basic income (loss) per common share:					
Income (loss) from continuing operations	$(2.74)	$0.58	$2.56	$0.75	$(0.96)
Income (loss) from discontinued operations	—	—	—	—	0.03
Net income (loss)	$(2.74)	$0.58	$2.56	$0.75	$(0.93)
Diluted income (loss) per common share:					
Income (loss) from continuing operations	$(2.74)	$0.57	$2.55	$0.75	$(0.96)
Income (loss) from discontinued operations	—	—	—	—	0.03
Net income (loss)	$(2.74)	$0.57	$2.55	$0.75	$(0.93)
Financial Position					
Cash and cash equivalents	$1,026.7	$1,332.1	$1,255.5	$484.2	$339.2
Property and equipment — net	$6,201.0	$6,552.7	$7,060.0	$7,405.8	$7,432.2
Total assets	$8,117.7	$8,458.3	$8,675.6	$8,347.3	$8,392.3
Current portion of long-term debt	$201.2	$—	$126.8	$—	$—
Long-term debt, less current portion	$2,309.7	$2,510.3	$2,553.4	$2,692.4	$2,788.5
Shareholders' equity(6)	$5,035.0	$5,386.1	$5,113.9	$4,772.5	$4,691.4
Statistical Information					
Current ratio (7)	2.87	6.06	3.27	2.80	2.82
Debt to capitalization ratio	33%	32%	34%	36%	37%
Book value per share of common stock outstanding	$39.62	$42.66	$40.76	$38.24	$37.66
Price range of common stock:					
High	$20.70	$20.50	$21.68	$25.13	$35.17
Low	$7.97	$9.02	$10.67	$14.63	$19.50
Cash dividends declared per share	$—	$—	$—	$0.40	$0.30

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(1) In 2018 and 2017, the Company recognized a $65.8 million and 157.4 million gain, respectively, on the sale of assets to ARO.

(2) Gain 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.

(3) Material charges and other operating expenses consisted of the following: 2016 – $34.3 million of non-cash impairment charges and a $1.4 million reversal of an estimated liability for settlement of a withholding tax matter during a tax amnesty period which was related to a legal settlement for a 2014 termination of a contract for refurbishment work on the Rowan Gorilla III, as noted below in the 2015 period. A payment of such withholding taxes during the tax amnesty period resulted in the waiver of applicable penalties and interest; 2015 – $329.8 million of non-cash asset impairment charges and a $7.6 million adjustment to an estimated liability for the 2014 termination of a contract for refurbishment work on the Rowan Gorilla III. A settlement agreement for this matter was signed during the third quarter of 2015; and 2014 – $574.0 million of non-cash asset impairment charges.

(4) In 2016, other income (expense), net includes a $31.2 million loss on debt extinguishment.

(5) In 2011, the Company sold its manufacturing and land drilling operations, which were 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.

(6) 2018 includes (i) a $5.5 million increase to Retained earnings related to the adoption of ASU No. 2014-09 and (ii) a $45.6 million increase to Retained earnings as a reclassification from Accumulated other comprehensive income related to the adoption of ASU No. 2018-02. 2017 includes a $206.6 million increase to Retained earnings related to the adoption of ASU No. 2016-16.

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

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

OUR BUSINESS

We are a global provider of offshore contract drilling services to the oil and gas industry, with a focus on ultra-deepwater drillships and high specification and premium jack-up rigs. Many of our high specification jack-up rigs are also rated for operating in harsh environments. Our fleet operates worldwide, including the US GOM, Mexico, Central and South America, the U.K. and Norwegian sectors of the North Sea, the Middle East and the Mediterranean Sea. We currently operate in three segments: Deepwater, Jack-ups and ARO, our 50/50 joint venture with Saudi Aramco. The Deepwater segment includes four ultra-deepwater drillships. The Jack-ups segment is composed of 21 self-elevating jack-up rigs and includes the impact of the various arrangements with ARO (see Note 1 and 4 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report for more information. The information discussed therein is incorporated by reference into this Part II, Item 7). ARO currently owns a fleet of seven self-elevating jack-up rigs for operation in the Arabian Gulf for Saudi Aramco. ARO has plans to order up to 20 new jack-up rigs over the next 10 years.

As of February 13, 2019, the date of our most recent Fleet Status Report, two of our four drillships were contracted in the US GOM, one was contracted in Mexico and the remaining drillship was marketed without a contract in the US GOM. For our jack-up fleet, we had four rigs under contract in the North Sea, one rig under contract in the Mediterranean Sea, three under contract in Central and South America and two under contract in the US GOM. In the Middle East, we had nine jack-ups leased to ARO to fulfill nine, three-year contracts between Saudi Aramco and ARO, two of which are expected to commence in the first half of 2019. Additionally, we own two jack-up rigs which are 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. Rigs leased to ARO are through bareboat charter agreements whereby substantially all operating costs will be borne by ARO. ARO will contract with the customer, Saudi Aramco, and directly receive related revenue.

Unless the context otherwise requires, the terms "Rowan", Rowan plc", "Company", "we", "us" and "our" are used to refer to Rowan plc and its consolidated subsidiaries. For Rowan plc and its consolidated subsidiaries, intercompany balances and transactions have been eliminated in consolidation.

For information with respect to our revenue and long-lived assets by geographic area, see Note 14 to our consolidated financial statements in Part II, Item 8 of this Annual Report.

Proposed Combination of Rowan Companies plc and Ensco plc

On October 7, 2018, the Company entered into a Transaction Agreement with Ensco plc to effect a "merger-of-equals" transaction (see discussion in "Proposed Combination of Rowan Companies plc and Ensco plc" included in Part I, Item 1. Business of this Annual Report for more information. The information discussed therein is incorporated by reference into this Part II, Item 7).

ARO Joint Venture

On November 21, 2016, Rowan and Saudi Aramco, through their subsidiaries, entered into a Shareholders' Agreement to create a 50/50 joint venture to own, manage and operate offshore drilling units in Saudi Arabia. The new entity, ARO, was formed in May 2017 and commenced operations on October 17, 2017. See Note 1 and Note 4 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report for additional information.

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Gain on sale of assets to unconsolidated subsidiary

Effective October 1, 2018, we sold the Scooter Yeargain and the Hank Boswell to ARO for total cash consideration of $266.0 million. The book value of these rigs was approximately $200.2 million. As a result of this sale transaction with ARO, we recognized a gain on the disposal of rigs in the amount of $65.8 million in 2018.

On October 17, 2017, pursuant to an Asset Transfer and Contribution Agreement with ARO, we agreed to sell three rigs to ARO: the JP Bussell, the Bob Keller and the Gilbert Rowe and related assets for total cash consideration of $357.7 million. The book value of these assets was approximately $200.3 million. As a result of this sale transaction with ARO, we recognized a gain on the disposal of rig assets in the amount of $157.4 million in 2017.
See Notes 1, 4 and 15 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report for additional information.

Anadarko Early Termination Revenue

During the second quarter of 2018, we recognized $27.8 million of revenue related to an early termination fee from Anadarko Petroleum Corporation (“Anadarko”) pursuant to our drilling contract for the drillship Rowan Resolute (the “Anadarko Contract”). Termination of the Anadarko Contract became effective on June 1, 2018, and the early termination fee was a lump sum payment for the remainder of the term of the Anadarko Contract, originally scheduled to terminate on August 6, 2018, at a rate of $418,400 per day.

Customer Contract Termination Amendment

On September 15, 2016, we amended our contract with Cobalt, for the drillship Rowan Reliance, which was scheduled to conclude on February 1, 2018. See Note 1 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report for additional information.

Customer Contract Termination and Settlement

On May 23, 2016, we reached an agreement with FMOG and its parent company, FCX, in connection with the drilling contract for the drillship Rowan Relentless, which was scheduled to terminate in June 2017. See Note 1 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report for additional information.

CURRENT BUSINESS ENVIRONMENT

Since the industry downturn in late 2014, the cancellation and postponement of drilling programs have resulted in significantly reduced demand for offshore drilling services globally and sharply lower day rates on newly executed contracts. The offshore rig supply and demand imbalance was further exacerbated by the delivery of 263 new jack-ups and 165 new floaters since the beginning of the most recent newbuild cycle, which started in early 2006. As of February 13, 2019, we believe that there remained approximately 77 additional jack-up rigs on order or under construction worldwide for delivery through 2021 (relative to approximately 311 jack-up rigs currently on contract), and 31 floaters on order or under construction worldwide for delivery through 2021 (relative to approximately 125 floater rigs currently on contract). To our knowledge, only one of the jack-up newbuilds has a contract in place and only one floater newbuild has a future contract executed. We expect delivery for many of the newbuilds to be deferred until a recovery in demand is more visible, and some rigs under construction may eventually be cancelled.
Drilling contractors have responded to the downturn by retiring assets, stacking certain idle equipment and deferring newbuild deliveries. Since the beginning of 2014, we estimate that approximately 89 jack-ups and 123 floaters have been removed from the total fleet in various forms of attrition. We have sold six of our oldest jack-ups, cold-stacked two of our older jack-ups, and have had as many as six warm stacked jack-ups and three warm stacked ultra-deepwater drillships during this period. Of these rigs that were once warm stacked, all but one, a drillship, have been put back to work and are currently contracted but at reduced dayrates. We have reduced day rates on certain drilling contracts, some in exchange for extended contract duration, agreed to certain contract terminations, and taken aggressive steps to reduce operating and support costs. We have also formed ARO, our joint venture with Saudi Aramco, to enhance our long-term competitive position with the world's largest user of jack-up rigs.

Overall utilization for marketed jack-ups has improved by over 10% since early 2017. Marketed utilization for drillships stabilized during much of 2018 and showed signs of improvement during the fourth quarter 2018. The general improvement in crude oil prices since mid-2017, albeit with a decline in the fourth quarter of 2018, combined with customers substantially lowering their break-even costs, has also led to a more favorable backdrop for drilling activity. Demand for jack-ups has increased fairly steadily over this period, and the improvement has particularly favored certain regions such as those with harsh environment conditions where there are fewer capable units. Industry demand for drillships shows recent signs of improvement although mostly for short

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term programs at dayrates that are still near historic lows, especially for near-term commencements. We expect any material improvement in dayrates for drillships will be delayed until a greater percentage of the remaining idle drillship capacity is utilized. By mid-2018, we concluded work on all of our legacy drillship contracts, which were signed at the prior peak of the market cycle, and looking forward, we expect our drillship contracts will be more in-line with current market rates. Our recent success at contracting three of our drillships, albeit for short-term work, in part reflects the general increase in tendering activity and the high quality of our rigs and strong operating performance.

While we have seen some recent improvement in contract awards, given the current offshore rig supply and demand dynamics, we expect the marketing environment to remain competitive across the broad offshore rig market until a more pronounced recovery in offshore rig demand materializes. Due to the short cycle nature of the shallow water markets, we expect jack-up demand to continue improving in advance of the floater market.

As the market stabilizes and improves, we believe that we are strategically well-positioned to take advantage of the next up-cycle given our financial condition, solid operational reputation, and modern fleet of active high-specification jack-ups and state-of-the-art ultra-deepwater drillships. We continue to focus on securing backlog, operating efficiency, cost reduction initiatives, and upgrading various systems and data analytics to drive improved drilling performance and predictive maintenance.

BACKLOG

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

	February 13, 2019		
	Jack-ups [1] [2]	Deepwater	Total
US GOM	$11.7	$ 79.9	$91.6
Mexico	—	18.3	18.3
Middle East [1] [2]	265.5	—	265.5
North Sea	184.1	—	184.1
Mediterranean Sea	10.8	—	10.8
Central and South America	64.6	—	64.6
Total backlog	$536.7	$ 98.2	$634.9

[1] Excludes ARO's revenue backlog.
[2] The total estimated revenue backlog includes $265.5 million of estimated bareboat charter and lease related revenue for nine jack-ups leased to ARO to fulfill contracts between ARO and Saudi Aramco. Substantially all the operating costs for jack-ups leased to ARO through bareboat charter agreements will be borne by ARO.

We estimate our backlog as of February 13, 2019, will be realized as follows (in millions):

Year Ended:	Jack-ups [1] [2]	Deepwater	Total
2019	$ 297.8	$ 87.6	$385.4
2020	159.2	10.6	169.8
2021	79.7	—	79.7
2022	—	—	—
2023 and later years	—	—	—

Total backlog	$ 536.7	$ 98.2	$ 634.9

(1) Excludes ARO's revenue backlog.
(2) The total estimated revenue backlog includes $265.5 million of estimated bareboat charter and lease related revenue for nine jack-ups leased to ARO to fulfill contracts between ARO and Saudi Aramco. Substantially all the operating costs for jack-ups leased to ARO through bareboat charter agreements will be borne by ARO.

Our contract backlog represents remaining contractual terms and may not reflect actual revenue due to renegotiations or a number of factors such as rig downtime, out of service time, estimated contract durations, changes in exchange rates for the non-U.S. dollar portion of day rates (the table above is based on rates as of February 13, 2019), contingent demobilization revenue, customer concessions or contract cancellations.

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About 73% of our remaining available rig days in 2019, 44% of available rig days in 2020 and 29% of available rig days in 2021, are included in backlog as revenue producing days as of February 13, 2019, excluding cold-stacked rigs. As of that date, we had two jack-ups that were cold stacked, and one drillship that was marketed without a contract. Since 2014, we have recognized asset impairment charges on several of our jack-up drilling units as a result of the decline in market conditions and the expectation of future demand and day rates. If our assumptions adversely change, we could be required to recognize additional impairment charges in future periods.

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RESULTS OF OPERATIONS

We analyze the financial results of each of our operating segments. The operating segments presented are consistent with our reportable segments discussed in Note 14 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report.

The following table presents certain key performance indicators by rig classification (10):

	Years ended December 31,		
	2018	2017	2016
Revenue (in millions):			
Deepwater			
Day rate revenue	$155.4	$465.7	$824.7
Rebillable revenue (1)	2.7	2.2	2.8
Total Deepwater	$158.1	$467.9	$827.5
Jack-ups			
Day rate revenue (2)	$556.1	$784.7	$994.7
Secondment revenue (1)	55.9	9.2	—
Rebillable revenue (1)	15.0	12.0	18.1
Miscellaneous revenue (1)	5.9	1.6	2.9
Total Jack-ups	$632.9	$807.5	$1,015.7
Unallocated			
Transition services revenue (1)	$33.8	$7.4	$—
Total revenue	$824.8	$1,282.8	$1,843.2
Revenue-producing days:			
Deepwater (3)	442	783	1,238
Jack-ups (4)	4,844	6,144	5,999
Total revenue-producing days (3) (4)	5,286	6,927	7,237
Available days: (5)			
Deepwater	1,460	1,460	1,464
Jack-ups	6,751	8,162	8,784
Total available days	8,211	9,622	10,248
Average day rate (in thousands): (6)			
Deepwater (3) (7) (8)	$351.2	$594.8	$550.7
Jack-ups	$114.8	$127.7	$165.8
Total fleet (3) (7) (8)	$134.6	$180.5	$231.7
Utilization: (9)			
Deepwater (3)	30 %	54 %	85 %
Jack-ups	72 %	75 %	68 %
Total fleet (3)	64 %	72 %	71 %

(1) Rebillable, secondment, miscellaneous and transition services revenue are excluded from the computation of average day rate.

(2) Dayrate revenue includes Bareboat Charter lease and related revenue from ARO of $24.4 million for the year ended December 31,

2018.

(3) Revenue-producing days for the year ended December 31, 2017, includes 125 days for the Deepwater drillship Rowan Reliance when it was not operating. The drillship did not operate in the third and fourth quarter of 2017, but was available for Cobalt through November 2, 2017, per the 2016 contract amendment (See Note 1 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report). Revenue of $70 million, previously deferred in 2016, was recognized during the year ended December 31, 2017, related to these days for which the rig was available to Cobalt but was not operating as well as the recognition of any remaining deferred revenue at November 2, 2017, as Cobalt did not exercise their right to use the rig.

(4) For rigs leased to ARO, revenue-producing days includes the number of days on hire under Bareboat Charter lease to ARO.

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(5) Available days are defined as the aggregate number of calendar days (excluding days for which a rig is cold-stacked) 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. In the case of rigs leased to ARO, the number of available days is based on the number of days available for hire under the Bareboat Charter lease to ARO.
(6) Average day rate is computed by dividing day rate revenue by the number of revenue-producing days, including fractional days. Day rate revenue includes the contractual rates, Bareboat Charter lease revenue from ARO and amounts received, such as for rig mobilization, unconstrained demobilization or capital improvements, which are amortized over the expected

recognition period of the contract. Revenue attributable to reimbursable expenses is excluded from average day rates.

(7) For the year ended December 31, 2018, revenue for this calculation includes $27.8 million related to the Anadarko early contract termination fee to which there are no associated revenue-producing days.

(8) Average day rate for 2016 includes operating days for the Rowan Relentless up to the contract termination, which was 143 days for 2016.

(9) Utilization is the number of revenue-producing days, including fractional days, divided by the number of available days. For rigs leased to ARO, utilization includes the number of days on hire under Bareboat Charter to ARO divided by the number of available days.

(10) All revenue and KPIs exclude the results from rigs owned by ARO beginning on

October 17, 2017, and October 1, 2018, the dates such rigs were sold to ARO.

Rig Utilization [4]

The following table sets forth an analysis of time that our rigs were idle or out-of-service as a percentage of available days (which excludes cold-stacked rigs) and time that our rigs experienced operational downtime and are off-rate as a percentage of revenue-producing days:

	Years ended December 31,		
	2018	2017	2016
Deepwater:			
Idle [1]	67.5 %	46.4 %	15.2 %
Out-of-service [2]	1.4 %	— %	0.1 %
Operational downtime [3]	2.6 %	— %	0.1 %
Jack-up:			
Idle [1]	16.1 %	15.7 %	25.4 %
Out-of-service [2]	11.0 %	8.1 %	5.3 %
Operational downtime [3]	1.6 %	1.3 %	1.4 %

[1] Idle Days – Days a rig is not under contract and is available to work. Idle days exclude cold-stacked rigs, which are not marketed.

[2] Out-of-Service Days – Those days when a rig is (or is 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 expected recognition period for the drilling contract.

[3] Operational Downtime – Unbillable time when a rig is under contract and unable to conduct planned operations due to equipment breakdowns or procedural failures.

[4] All revenue and utilization metrics exclude the results from rigs owned by ARO beginning on October 17, 2017, and October 1, 2018, the dates such rigs were sold to ARO.

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2018 Compared to 2017

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

	Year ended December 31, 2018	2017	Change	% Change
Deepwater:				
Revenue	$158.1	$467.9	$(309.8)	(66)%
Operating expenses:				
Direct operating costs (excluding items below)	168.6	151.4	17.2	11%
Depreciation and amortization	108.5	111.6	(3.1)	(3)%
Other operating items - expense	1.6	0.1	1.5	n/m
Income (loss) from operations	$(120.6)	$204.8	$(325.4)	n/m
Jack-ups:				
Revenue	$632.9	$807.5	$(174.6)	(22)%
Operating expenses:				
Direct operating costs (excluding items below)	514.1	533.6	(19.5)	(4)%
Depreciation and amortization	278.3	289.4	(11.1)	(4)%
Gain on sale of assets to unconsolidated subsidiary	(65.8)	(157.4)	91.6	n/m
Other operating items - expense	5.3	9.3	(4.0)	n/m
Income (loss) from operations	$(99.0)	$132.6	$(231.6)	n/m
ARO:				
Revenue	$348.8	$48.6	$300.2	n/m
Operating expenses:				
Direct operating costs (excluding items below)	194.0	22.2	171.8	n/m
Depreciation and amortization	67.4	12.9	54.5	n/m
Selling, general and administrative	27.0	6.1	20.9	n/m
Other operating items - (income) expense	1.4	(0.1)	1.5	n/m
Income from operations	$59.0	$7.5	$51.5	n/m
Unallocated and other:				
Revenue	$33.8	$7.4	$26.4	n/m
Operating expenses:				
Depreciation and amortization	2.1	2.7	(0.6)	(22)%
Selling, general and administrative	96.1	104.6	(8.5)	(8)%
Other operating items - expense	5.2	—	5.2	n/m
Merger and related costs	8.9	—	8.9	n/m
Loss from operations	$(78.5)	$(99.9)	$21.4	(21)%

“n/m” - not meaningful.

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	Year ended December 31,			
	2018	2017	Change	% Change
Reportable segments total:				
Revenue	$1,173.6	$1,331.4		
Operating expenses:				
Direct operating costs (excluding items below)	876.7	707.2		
Depreciation and amortization	456.3	416.6		
Selling, general and administrative	123.1	110.7		
Gain on sale of assets to unconsolidated subsidiary	(65.8)	(157.4)		
Other operating items - expense	13.5	9.3		
Merger and related costs	8.9	—		
Income (loss) from operations	$(239.1)	$245.0		
Eliminations and adjustments:				
Revenue	$(348.8)	$(48.6)		
Operating expenses:				
Direct operating costs (excluding items below)	(194.0)	(22.2)		
Depreciation and amortization	(67.4)	(12.9)		
Selling, general and administrative	(27.0)	(6.1)		
Other operating items - income (expense)	(1.4)	0.1		
Equity in earnings of unconsolidated subsidiary	10.3	0.9		
Loss from operations	$(48.7)	$(6.6)		
Total company:				
Revenue	$824.8	$1,282.8	$(458.0)	(36)%
Direct operating costs (excluding items below)	682.7	685.0	(2.3)	—%
Depreciation and amortization	388.9	403.7	(14.8)	(4)%
Selling, general and administrative	96.1	104.6	(8.5)	(8)%
Gain on sale of assets to unconsolidated subsidiary	(65.8)	(157.4)	91.6	n/m
Other operating items - expense	12.1	9.4	2.7	n/m
Merger and related costs	8.9	—	8.9	n/m
Equity in earnings of unconsolidated subsidiary	10.3	0.9	9.4	n/m
Income (loss) from operations	$(287.8)	$238.4	$(526.2)	n/m
Other (expense), net	(111.2)	(139.1)	27.9	(20)%
Income (loss) before income taxes	(399.0)	99.3	(498.3)	n/m
Provision (benefit) for income taxes	(51.6)	26.6	(78.2)	n/m
Net Income (loss)	$(347.4)	$72.7	$(420.1)	n/m

“n/m” - not meaningful.

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Revenue

Consolidated. The decrease in consolidated revenue is described below.

Deepwater. The net changes in revenue for 2018, compared to 2017, are set forth below (in millions):

	Increase (decrease)
Fewer revenue-producing days	$ (224.6)
Lower average drillship day rates	(84.9)
Rowan Reliance acceleration [1]	(28.6)
Rowan Resolute-Anadarko early contract termination fee	27.8
Higher reimbursable revenue	0.5
Decrease	$ (309.8)

[1] In November 2017 the Company accelerated the recognition of approximately $29 million in previously deferred revenue for the Rowan Reliance (to which no operating days were associated) as Cobalt did not exercise their right to use the rig.

Jack-ups. The net changes in revenue for 2018, compared to 2017, are set forth below (in millions):

	Increase (decrease)
ARO related - decrease due to sale of assets to ARO	$ (99.3)
ARO related - increase in ARO related secondment reimbursables	46.7
ARO related - increase due to idle rigs leased to ARO	3.5
Lower average jack-up day rates [1]	(51.3)
Fewer revenue-producing days	(81.5)
Higher other revenue	7.3
Decrease	$ (174.6)

[1] The decrease is primarily due to five of the jack-ups leased to ARO through Bareboat Charters a portion of the year ended December 31, 2018, whereby substantially all operating costs will be borne by ARO. This is compared to those five jack-ups being contracted directly to Saudi Aramco for a dayrate during the comparable period, whereby all of the operating costs were borne by the Company. The reduction in rate (Bareboat Charter rate compared to Dayrate) contributed to a decrease in Revenue of approximately $42.3 million. Additionally, the EXL IV and EXL I were leased to ARO through Bareboat Charters, but were idle during 2017. These rigs contributed $3.5 million in revenue in 2018.

Unallocated. Revenue related to transition services provided to ARO increased as a result of ARO operating a full year in 2018 compared to commencing operations on October 17, 2017 for the comparable period (see Note 1 and Note 4 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report).

Direct operating costs

Consolidated. The decrease in consolidated direct operating costs is described below.

Deepwater. The net changes in direct operating costs for 2018, compared to 2017, are set forth below (in millions):

	Increase (decrease)
Increase in drillship direct operating expenses [1]	$ 33.8
Higher reimbursable costs	0.5
Decrease due to idle drillships	(15.0)
Reduction in shorebase costs and other	(2.1)

Increase	$ 17.2

(1) Primarily due to ramp up and non-recoverable preparation costs.

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Jack-ups. The net changes in direct operating costs for 2018, compared to 2017, are set forth below (in millions):

	Increase (decrease)
ARO related - decrease due to sale of assets to ARO	$ (62.3)
ARO related - decrease due to rigs leased to ARO	(24.3)
ARO related - increase to secondment reimbursable costs	46.7
ARO related - management fee	25.7
Decrease due to idle or cold-stacked rigs	(18.9)
Reduction in shorebase costs and other	(18.5)
Ramp up costs, non-recoverable preparation costs, repairs and maintenance expenses for Bess Brants, Earnest Dees, EXL I and EXL IV for lease to ARO	24.7
Increase in jack-up direct operating expense	4.4
Higher reimbursable costs	3.0
Decrease	$ (19.5)

Selling, General and Administrative

The decrease in Selling, general and administrative expenses was primarily due to lower personnel costs.

Gain on sale of assets to unconsolidated subsidiary

We recognized a gain of $65.8 million and $157.4 million in 2018 and 2017, respectively, on the sale of assets to ARO. See Notes 1, 4 and 15 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report for additional information.

Merger and related costs

We recognized $8.9 million of expense, primarily legal and other professional service fees, related to our proposed merger with Ensco.

Other operating items

In 2018, we had a loss on disposals of property and equipment of $12.1 million compared to a loss of $9.4 million in 2017.

Equity in earnings of unconsolidated subsidiary

Equity in earnings of unconsolidated subsidiary increased largely as a result of ARO operating a full year in 2018 compared to commencing operations on October 17, 2017, for the comparable period.

Other expense, net

The decrease in Other expense, net, is primarily due to the following:

- $10.8 million increase in interest income from ARO note receivable primarily due to balances outstanding a full year in 2018 compared to a partial year in 2017, the period from October 17, 2017 to December 31, 2017, (see Note 4 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report for additional information);
- $6.9 million increase in interest income on cash balances due to higher interest rates.
- Benefit of $15.2 million in 2018 from pension and other postretirement benefit plans net periodic cost, exclusive of service cost compared to an expense of $0.1 million in 2017. The benefit in 2018 was primarily due to a pension plan curtailment gain of $11.4 million in the second quarter of 2018. The 2017 period included a $5.8 million settlement loss related to an annuity purchase.

Partially offsetting these items,

- Increase in net foreign currency exchange losses of $3.0 million; and
- Gain on the early extinguishment of debt in 2017 of $1.7 million.

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Provision (benefit) for income taxes

In 2018, we recognized an income tax benefit of $51.6 million on pretax loss of $399.0 million. The 2018 tax benefit primarily includes $68.4 million from the reversal of a valuation allowance on U.S. deferred tax assets, $10.2 million of adjustments for filed tax returns, and $9.3 million reduction in accrued unrecognized tax benefits due to a lapse in statutes of limitation partially offset by $32.4 million of tax expense for current year operations and $2.9 million of additional unrecognized tax benefits related to potential audit settlement and transfer pricing.

In 2017, we recognized an income tax provision of $26.6 million on pretax income of $99.3 million. The 2017 tax provision primarily included $28.7 million of tax expense for 2017 operations, $20.5 million of tax expense due to an increase in the valuation allowance assessed on deferred tax assets, and a partial offset by a $27.3 million reduction in accrued unrecognized tax benefits due to a lapse in statutes of limitation and an audit settlement.

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2017 Compared to 2016

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

	Year ended December 31, 2017	2016	Change	% Change
Deepwater:				
Revenue	$467.9	$827.5	$(359.6)	(43)%
Operating expenses:				
Direct operating costs (excluding items below)	151.4	222.4	(71.0)	(32)%
Depreciation and amortization	111.6	115.0	(3.4)	(3)%
Other operating items - expense	0.1	0.1	—	n/m
Income from operations	$204.8	$490.0	$(285.2)	(58)%
Jack-ups:				
Revenue	$807.5	$1,015.7	$(208.2)	(20)%
Operating expenses:				
Direct operating costs (excluding items below)	533.6	557.3	(23.7)	(4)%
Depreciation and amortization	289.4	282.6	6.8	2%
Gain on sale of assets to unconsolidated subsidiary	(157.4)	—	(157.4)	n/m
Other operating items - expense	9.3	40.9	(31.6)	n/m
Income from operations	$132.6	$134.9	$(2.3)	(2)%
ARO:				
Revenue	$48.6	$—		
Operating expenses:				
Direct operating costs (excluding items below)	22.2	—		
Depreciation and amortization	12.9	—		
Selling, general and administrative	6.1	—		
Other operating items - income	(0.1)	—		
Income from operations	$7.5	$—		
Unallocated and other:				
Revenue	$7.4	$—	$7.4	n/m
Operating expenses:				
Depreciation and amortization	2.7	5.3	(2.6)	(49)%
Selling, general and administrative	104.6	102.2	2.4	2%
Other operating items - expense	—	0.6	(0.6)	n/m
Loss from operations	$(99.9)	$(108.1)	$8.2	(8)%

“n/m” - not meaningful.

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	Year ended December 31, 2017	2016	Change	% Change
Reportable segments total:				
Revenue	$1,331.4	$1,843.2		
Operating expenses:				
Direct operating costs (excluding items below)	707.2	779.7		
Depreciation and amortization	416.6	402.9		
Selling, general and administrative	110.7	102.2		
Gain on sale of assets to unconsolidated subsidiary	(157.4)	—		
Other operating items - expense	9.3	41.6		
Income from operations	$245.0	$516.8		
Eliminations and adjustments:				
Revenue	$(48.6)	$—		
Operating expenses:				
Direct operating costs (excluding items below)	(22.2)	—		
Depreciation and amortization	(12.9)	—		
Selling, general and administrative	(6.1)	—		
Other operating items - income	0.1	—		
Equity in earnings of unconsolidated subsidiary	0.9	—		
Loss from operations	$(6.6)	$—		
Total company:				
Revenue	$1,282.8	$1,843.2	$(560.4)	(30)%
Direct operating costs (excluding items below)	685.0	779.7	(94.7)	(12)%
Depreciation and amortization	403.7	402.9	0.8	— %
Selling, general and administrative	104.6	102.2	2.4	2 %
Gain on sale of assets to unconsolidated subsidiary	(157.4)	—	(157.4)	n/m
Other operating items - expense	9.4	41.6	(32.2)	n/m
Equity in earnings of unconsolidated subsidiary	0.9	—	0.9	n/m
Income from operations	$238.4	$516.8	$(278.4)	(54)%
Other (expense), net	(139.1)	(191.2)	52.1	(27)%
Income before income taxes	99.3	325.6	(226.3)	(70)%
Provision for income taxes	26.6	5.0	21.6	n/m
Net Income	$72.7	$320.6	$(247.9)	(77)%

“n/m” - not meaningful.

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Revenue

Consolidated. The decrease in consolidated revenue is described below.

Deepwater. The net changes in revenue for 2017, compared to 2016, are set forth below (in millions):

	Increase (decrease)
Fewer operating days	$ (277.1)
Prior year Contract Termination for Rowan Relentless and related items	(142.7)
Lower reimbursable revenue	(0.6)
Higher drillship day rates [1]	60.8
Decrease	$ (359.6)

[1] Higher average drillship day rates resulted largely from the blend and extend arrangement for the Rowan Resolute. In addition, in November 2017 the Company accelerated the recognition of approximately $29 million in previously deferred revenue for the Rowan Reliance (to which no operating days were associated) as Cobalt did not exercise their right to use the rig. These increases were partially offset by a decrease for the Rowan Reliance due to lower average day rates in 2017 compared to 2016.

Jack-ups. The net changes in revenue for 2017, compared to 2016, are set forth below (in millions):

	Increase (decrease)
Lower jack-up day rates	$ (244.2)
Lower reimbursable revenue	(6.1)
Lower other revenue	(1.3)
Increased operating days	46.8
ARO related - decrease due to sale of assets to ARO	(12.6)
ARO related - increase in secondment reimbursables	9.2
Decrease	$ (208.2)

Unallocated. From October 17, 2017, to December 31, 2017, we recorded $7.4 million of revenue related to transition services provided to ARO (see Note 1 and Note 4 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report).

Direct operating costs

Consolidated. The decrease in consolidated direct operating costs is described below.

Deepwater. The net changes in direct operating costs for 2017, compared to 2016, are set forth below (in millions):

	Decrease
Decrease due to idle drillships	$ (44.8)
Reduction in shore base costs and other	(17.6)
Reduction in drillship direct operating expenses	(8.0)
Lower reimbursable costs	(0.6)
Decrease	$ (71.0)

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Jack-ups. The net changes in direct operating costs for 2017, compared to 2016, are set forth below (in millions):

	Increase (decrease)
Decrease due to idle or cold-stacked rigs	$ (21.5)
Lower reimbursable costs	(6.1)
Reduction in jack-up direct operating expenses	(3.2)
Reduction in shore base costs and other	(2.1)
ARO related - decrease due to sale of assets to ARO	(7.8)
ARO related - increase in secondment reimbursable costs	9.2
ARO related - management fee	7.8
Decrease	$ (23.7)

Gain on sale of assets to unconsolidated subsidiary

In 2017, we recognized a gain of $157.4 million on the sale of assets to ARO. See Notes 1, 4 and 15 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report for additional information.

Other operating items

Material charges for 2016 included a $34.3 million non-cash impairment charge to reduce the carrying values of five of our jack-up drilling units, partially offset by a $1.4 million reversal of an estimated liability for settlement of a withholding tax matter during a tax amnesty period which was related to a legal settlement for a 2014 termination of a contract for refurbishment work on the Rowan Gorilla III. Payment of such withholding taxes during the tax amnesty period resulted in the waiver of applicable penalties and interest.

In 2017, we had a loss on disposals of property and equipment of $9.4 million compared to a loss of $8.7 million in 2016.

Other expense, net

The decrease in Other expense, net, is primarily due to a $1.7 million gain on the early extinguishment of debt in 2017 compared to a net loss on the early extinguishment of debt of $31.2 million in 2016. Interest income increased in 2017 primarily due to higher cash balances in 2017 as compared to 2016, and $2.1 million of interest income related to the note receivable from ARO (see Note 4 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report). Additionally, our foreign currency exchange losses decreased to $0.4 million in 2017 compared to $9.7 million in 2016 primarily due to the devaluation of the Egyptian pound in 2016.

Provision for income taxes

In 2017, we recognized an income tax provision of $26.6 million on pretax income of $99.3 million. The 2017 tax provision primarily included $28.7 million of tax expense for 2017 operations, $20.5 million of tax expense due to an increase in the valuation allowance assessed on deferred tax assets, and a partial offset by a $27.3 million reduction in accrued unrecognized tax benefits due to a lapse in statutes of limitation and an audit settlement.

In 2016, we recognized an income tax provision of $5.0 million on pretax income of $325.6 million. The 2016 tax provision was primarily due to 2016 operations offset by the amortization of deferred intercompany gains and losses and deferred tax benefit as a result of 2016 restructuring.

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LIQUIDITY AND CAPITAL RESOURCES

Key balance sheet amounts, ratios and availability under the New Credit Facility and Existing Credit Facility at December 31 were as follows (dollars in millions):

	2018	2017
Cash and cash equivalents	$1,026.7	$1,332.1
Current assets	$1,300.3	$1,560.4
Current liabilities	$453.6	$257.4
Current ratio	2.87	6.06
Current portion of long-term debt	$201.2	$—
Long-term debt	$2,309.7	$2,510.3
Outstanding letters of credit	$9.1	$7.3
Shareholders' equity	$5,035.0	$5,386.1
Debt-to-capitalization ratio (1)	33 %	32 %
Availability under New Credit Facility and Existing Credit Facility (2)	$1,258.9	$1,495.0

(1) Includes outstanding letters of credit as outstanding debt.

(2) On January 23, 2019, $60.0 million of availability under the Existing Credit Facility matured and is no longer available.

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

	Years ended December 31,		
	2018	2017	2016
Net cash provided by (used in) operations	$ (160.1)	$ 299.8	$ 929.6
Capital expenditures	(169.2)	(100.6)	(117.6)
Purchase of rigs	(70.8)	—	—
Deposit on purchase of rigs	—	(7.7)	—
Investment in unconsolidated subsidiary	—	(30.0)	—
Contributions to unconsolidated subsidiary for note receivable	(271.3)	(357.7)	—
Proceeds from sale of assets to unconsolidated subsidiary	266.0	357.7	—
Repayments of note receivable from unconsolidated subsidiary	98.5	87.5	—
Proceeds from disposals of property and equipment	12.7	3.3	6.2
Proceeds from borrowings	—	—	500.0
	—	(170.0)	(511.8)

Reductions of long-term debt			
Payment of debt extinguishment costs	—	—	(24.0)
Debt issue costs	(6.1)	—	(8.7)
Shares repurchased for tax withholdings on vesting of restricted share units	(5.2)	(5.7)	(5.0)
Proceeds from exercise of share options	0.1	—	—
Excess tax benefits from share-based compensation	—	—	2.6
Total net source (use)	$ (305.4)	$ 76.6	$ 771.3

Operating Cash Flows

We used cash in operations of approximately $160 million in 2018 compared to cash generated from operations of approximately $300 million in 2017. The decrease is primarily due to lower dayrates and drilling activity in 2018. Operating cash flows for 2017 compared to 2016 decreased primarily due to lower dayrates and drilling activity in 2017 as well as the impact of contract termination settlements in 2016.

We have not provided deferred income taxes on certain undistributed earnings of non-U.K. subsidiaries. If facts and circumstances cause a change in expectations regarding future tax consequences, the resulting tax impact could have a material effect on the Company’s consolidated financial statements.

Investing Activities
2018
Capital expenditures in 2018 totaled $169.2 million. In addition, we spent $70.8 million, which includes transaction costs of $1.5 million, for the purchase of two 2013 built Le Tourneau Super 116E jack-ups in January 2018.
We contributed $271.3 million in cash to ARO in exchange for a note receivable. We received cash proceeds from ARO of $266.0 million for the purchase of two rigs. Additionally, during the year ended December 31, 2018, we received $98.5 million from ARO for repayments of the shareholder note receivable.

2017
Capital expenditures for 2017 totaled $100.6 million and included $70.5 million for improvements to the existing fleet, including contractually required modifications, and $30.1 million for rig equipment and other. A cash deposit of $7.7 million was also made toward the purchase of two 2013 built Le Tourneau Super 166E jack-up rigs discussed above.
In connection with the formation of ARO in 2017, we contributed $25 million to be used by the joint venture for working capital needs and incurred $5.0 million in transaction costs that were both capitalized to the investment in ARO. We contributed $357.7 million in cash to ARO in exchange for a note receivable from ARO. We received cash proceeds from ARO of $357.7 million for the purchase of three rigs and related assets. Additionally, we received $87.5 million in cash from ARO for repayment of the shareholder note receivable.
2016
Capital expenditures for 2016 totaled $117.6 million and included $68.5 million for improvements to the existing fleet, including contractually required modifications, and $49.1 million for rig equipment and other.
2019 Estimates
We currently estimate our 2019 capital expenditures will range from approximately $125-135 million, which is primarily for fleet maintenance, rig equipment, spares, upgrades to prepare the Bess Brants and Earnest Dees for service (see above), contractual modifications for Bess Brants and Earnest Dees for their lease to ARO to fulfill contracts with Saudi Aramco and other contractual modifications for the Rowan Stavanger for its contract with Equinor. This amount excludes any other contractual modifications that may arise due to our securing additional work.
We expect to fund our 2019 capital expenditures using cash on hand.
Our capital estimate reflects cash that we may or may not spend, and the timing of such expenditures may change. We will periodically review and adjust the capital forecast as necessary based upon current and expected cash flows and liquidity, anticipated market conditions in our business, the availability of financial resources, and alternative uses of capital to enhance shareholder value.
Financing Activities
The Senior Notes and any amounts outstanding under our New Credit Facility and Existing Credit Facility are fully, unconditionally and irrevocably guaranteed on a senior and unsecured basis by Rowan plc. We were in compliance with our debt covenants under our New Credit Facility and Existing Credit Facility at December 31, 2018, and expect to remain in compliance throughout 2019.
Annual interest payments on the Senior Notes are estimated to be approximately $155 million in 2019. No principal payments are required until each series' final maturity date. Management believes that existing cash balances and amounts available under our New Credit Facility and Existing Credit Facility will be sufficient to satisfy the Company's cash requirements for the following twelve months, including the repayment of our 7.875% Senior Notes due in August 2019.
Additional information related to our Senior Notes, New Credit Facility and Existing Credit Facility is described in Note 6 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report and the information discussed therein is incorporated by reference into this Part II, Item 7.
Cash Dividends
In January 2016, the Company announced that it had discontinued its quarterly dividend.

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Off-balance Sheet Arrangements and Contractual Obligations

The Company had no off-balance sheet arrangements as of December 31, 2018 or 2017, other than operating lease obligations and other commitments in the ordinary course of business.

The following is a summary of our contractual obligations at December 31, 2018, 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	$2,520	$ 201	$ —	$ 621	$ 1,698
Interest on Senior Notes	1,549	140	262	214	933
Purchase obligations	128	128	—	—	—
Operating leases	28	8	7	3	10
Total	$4,225	$ 477	$ 269	$ 838	$ 2,641

As of December 31, 2018, our liability for unrecognized tax benefits related to uncertain tax positions totaled $111 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 in the normal course of our business and had outstanding letters of credit of approximately $9.1 million at December 31, 2018, of which $6.8 million were issued under our New Credit Facility.

Rowan has a potential obligation to fund ARO for newbuild jack-up rigs. See Note 9 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report and the information discussed therein is incorporated by reference into this Part II, Item 7.

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, 2018, our financial statements reflected an aggregate unfunded pension liability of $223 million. We expect to make minimum contributions to our defined benefit pension plans of approximately $15 million in 2019, 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 routine legal proceedings incidental to our businesses and are vigorously defending our position in all such matters. Although the outcome of such proceedings cannot be predicted with certainty, we believe there are no known contingencies, claims or lawsuits that will have a material adverse effect on our financial position, results of operations or cash flows. Information relating to contingencies is described in Note 9 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report. The information discussed therein is incorporated by reference into this Part II, Item 7.

CRITICAL ACCOUNTING POLICIES AND MANAGEMENT ESTIMATES

Our significant accounting policies are presented in Note 2 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report. 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 revenue and expenses during the reporting period. We believe that our most critical accounting policies and management estimates involve carrying values of long-lived assets, principles of consolidation and our equity method investment, 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.

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.

Subsequent to the October 2018 announcement of the proposed combination with Ensco, we conducted an impairment test of our assets; however, the test resulted in no impairment as the estimated undiscounted cash flows from the assets exceeded the assets' carrying values.

During the fourth quarter of 2017, we conducted an impairment test of our assets; however, the test resulted in no impairment as the estimated undiscounted cash flows from the assets exceeded the assets' carrying values (see Note 2 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report).

In 2016, we conducted an impairment test 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 $34 million (see Note 2 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report).

Principles of Consolidation

The consolidated financial statements include our accounts and those of our wholly-owned subsidiaries. Intercompany balances and transactions have been eliminated in consolidation. Investments in operating entities where we have the ability to exercise significant influence, but where we do not control operating and financial policies are accounted for using the equity method. Significant influence generally exists if we have an ownership interest representing between 20% and 50% of the voting stock of the investee. Under the equity method of accounting, investments are stated at initial cost and are adjusted for subsequent additional investments and our proportionate share of earnings or losses and distributions. We account for our interest in ARO using the equity method of accounting and only recognize our portion of equity earnings in our consolidated financial statements. ARO is a variable interest entity; however, we are not the primary beneficiary and therefore do not consolidate ARO. Our judgment regarding the level of influence over ARO included considering key factors such as each company's ownership interest, representation on the board of managers of ARO, ability to direct activities that most significantly impact ARO's economic performance, as well as the ability to influence policy-making decisions.

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, 2018, included (i) a weighted average discount rate of 4.35% to determine pension benefit obligations, (ii) a weighted average discount rate of 3.69% to determine net periodic pension cost and (iii), an expected long-term rate of return on pension plan assets of 6.70%. 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 $86.6 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 $5.4 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 6.70% at both December 31, 2018 and 2017.

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 appropriate reserve. Income tax returns are subject to audit by taxing authorities in most jurisdictions. 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 $98 million at December 31, 2018, is properly recorded in accordance with the accounting guidelines.

On December 22, 2017, the U.S. Tax Act was enacted into law and the new legislation contains several key tax provisions, including a one-time mandatory transition tax on certain non-U.S. earnings, a reduction of the corporate income tax rate to 21%, a change in the taxability of certain non-U.S. subsidiaries, an additional tax on certain payments made from U.S. affiliates to non-U.S. affiliates, a limitation on interest deduction and a tax imposed on non-U.S. income in excess of a deemed return on tangible assets of non-U.S. corporations among others. In December 2017, the SEC staff issued Staff Accounting Bulletin No. 118, Income Tax Accounting Implications of the Tax Cuts and Jobs Act (SAB 118), which allows us to record provisional amounts during a measurement period not to extend beyond one year of the enactment date. Since the U.S. Tax Act was passed late in the fourth quarter of 2017, provisional estimates were reported in the year ended December 31, 2017. During 2018, we finalized the accounting for this matter. The impacts from the U.S. Tax Act are more fully described in Note 13 of the "Consolidated Financial Statements" Part II, Item 8 of this Annual Report.

In January 2018, the FASB released guidance on the accounting for tax on the global intangible low-taxed income ("GILTI") provisions of the U.S. Tax Act. The GILTI provisions impose a tax on non-U.S. income in excess of a deemed return on tangible assets of non-U.S. corporations. The guidance indicates that either accounting for deferred taxes related to GILTI inclusions or treating any taxes on GILTI inclusions as period cost are both acceptable methods subject to an accounting policy election. The Company is currently not subject to GILTI and will determine this election in the future as guidance requires.

Accounting Pronouncements

Information relating to accounting pronouncements is described in Note 2 of the "Consolidated Financial Statements" in Part II, Item 8 of this Annual Report and the information discussed therein is incorporated by reference into this Part II, Item 7.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

Interest rate risk – Our outstanding debt at December 31, 2018, consisted entirely of fixed-rate debt with a carrying value of $2.511 billion and a weighted-average annual interest rate of 5.8%. We are subject to interest rate risk on our fixed-interest rate borrowings. Fixed rate debt, where the interest rate is fixed over the life of the instrument, exposes us to changes in market interest rates reflected in the fair value of the debt and to the risk that we may need to refinance maturing debt with new debt at a higher rate.

Our Long-term note receivable from unconsolidated subsidiary bears interest at a stated interest rate of LIBOR plus two percent with a carrying value of $456.0 million at December 31, 2018. A one-percentage-point decrease in LIBOR would decrease our interest income by approximately $5 million in the next twelve months, while a one-percentage-point increase in LIBOR would increase our interest income by approximately $5 million in the same period.

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Currency exchange rate risk – A substantial majority of our revenue is received in USD, which is our functional currency. However, in certain countries in which we operate, local laws or contracts may require us to receive some 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. We did not enter into such transactions for the purpose of speculation, trading or investing in the market. Our risk policy allows us to enter into such forward exchange contracts; however, we do not currently anticipate entering into such transactions in the future and had no such contracts outstanding as of December 31, 2018.

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

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the shareholders and the Board of Directors of Rowan Companies plc

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Rowan Companies plc and subsidiaries (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of operations, comprehensive income, changes in shareholders' equity, and cash flows, for each of the three years in the period ended December 31, 2018, and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2019, expressed an unqualified opinion on the Company's internal control over financial reporting.

Change in Accounting Principle

The Company has changed its method of accounting for current and deferred income tax effects for intra-entity transfers of assets other than inventory in 2017 due to the adoption of Accounting Standards Update No. 2016-16, Income Taxes (ASC 740): Intra-Entity Transfers of Assets Other than Inventory.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
February 27, 2019

We have served as the Company's auditor since 1966.

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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, 2018.

The independent registered public accounting firm Deloitte & Touche LLP has audited Rowan's consolidated financial statements and financial statement schedule included in our 2018 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	/s/ STEPHEN M. BUTZ
Thomas P. Burke	Stephen M. Butz
President and Chief Executive Officer	Executive Vice President and Chief Financial Officer
February 27, 2019	February 27, 2019

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the shareholders and the Board of Directors of Rowan Companies plc

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Rowan Companies plc and subsidiaries (the "Company") as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2018, of the Company and our report dated February 27, 2019 expressed an unqualified opinion on those financial statements and financial statement schedule, and included an explanatory paragraph relating to the Company's adoption of Accounting Standards Update No. 2016-16, Income Taxes (ASC 740): Intra-Entity Transfers of Assets Other than Inventory.

Basis for Opinion

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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 27, 2019

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ROWAN COMPANIES PLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(In millions, except per share amounts)

	Years ended December 31,		
	2018	2017	2016
REVENUE	$824.8	$1,282.8	$1,843.2
COSTS AND EXPENSES:			
Direct operating costs (excluding items below)	682.7	685.0	779.7
Depreciation and amortization	388.9	403.7	402.9
Selling, general and administrative	96.1	104.6	102.2
Gain on sale of assets to unconsolidated subsidiary	(65.8)	(157.4)	—
Loss on disposals of property and equipment	12.1	9.4	8.7
Merger and related costs	8.9	—	—
Material charges and other operating items	—	—	32.9
Total costs and expenses	1,122.9	1,045.3	1,326.4
Equity in earnings of unconsolidated subsidiary	10.3	0.9	—
INCOME (LOSS) FROM OPERATIONS	(287.8)	238.4	516.8
OTHER INCOME (EXPENSE):			
Interest expense	(156.3)	(155.7)	(155.5)
Interest income	33.1	15.4	3.8
Gain (Loss) on extinguishment of debt	—	1.7	(31.2)
Other - net	12.0	(0.5)	(8.3)
Total other (expense) - net	(111.2)	(139.1)	(191.2)
INCOME (LOSS) BEFORE INCOME TAXES	(399.0)	99.3	325.6
Provision (benefit) for income taxes	(51.6)	26.6	5.0
NET INCOME (LOSS)	$(347.4)	$72.7	$320.6
NET INCOME (LOSS) PER SHARE - BASIC:	$(2.74)	$0.58	$2.56
NET INCOME (LOSS) PER SHARE - DILUTED:	$(2.74)	$0.57	$2.55

See Notes to Consolidated Financial Statements.

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ROWAN COMPANIES PLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(In millions)

	Years ended December 31,		
	2018	2017	2016
NET INCOME (LOSS)	$(347.4)	$72.7	$320.6
OTHER COMPREHENSIVE INCOME (LOSS)			
Net changes in pension and other postretirement plan assets and benefit obligations recognized in other comprehensive income (loss), net of income tax expense (benefit) of $(4.8), $0, and $(2.8), respectively.	(17.9)	(33.3)	(5.1)
Net reclassification adjustment for amounts recognized in net income (loss) as a component of net periodic benefit cost, net of income tax expense (benefit) of $(1.5), $0, and $3.8, respectively.	(5.6)	11.4	7.4
	(23.5)	(21.9)	2.3
COMPREHENSIVE INCOME (LOSS)	$(370.9)	$50.8	$322.9

See Notes to Consolidated Financial Statements.

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ROWAN COMPANIES PLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In millions, except par value)

	December 31, 2018	2017
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$1,026.7	$1,332.1
Receivables - trade and other	251.2	212.8
Prepaid expenses and other current assets	22.4	15.5
Total current assets	1,300.3	1,560.4
PROPERTY AND EQUIPMENT:		
Drilling equipment	8,510.7	8,697.8
Other property and equipment	141.7	136.1
Property and equipment - gross	8,652.4	8,833.9
Less accumulated depreciation and amortization	2,451.4	2,281.2
Property and equipment - net	6,201.0	6,552.7
Long-term note receivable from unconsolidated subsidiary	456.0	270.2
Investment in unconsolidated subsidiary	41.2	30.9
Other assets	119.2	44.1
	$8,117.7	$8,458.3
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Current portion of long-term debt	$201.2	$—
Accounts payable - trade	122.3	97.2
Deferred revenue	16.7	1.1
Accrued liabilities	113.4	159.1
Total current liabilities	453.6	257.4
Long-term debt	2,309.7	2,510.3
Other liabilities	307.7	293.6
Deferred income taxes - net	11.7	10.9
Commitments and contingent liabilities (Note 9)		
SHAREHOLDERS' EQUITY:		
Class A Ordinary Shares, $0.125 par value; 128.2 and 128.1 shares issued, respectively; 127.1 and 126.3 shares outstanding, respectively	16.0	16.0
Additional paid-in capital	1,501.5	1,488.6
Retained earnings	3,810.5	4,109.7
Cost of 1.1 and 1.8 treasury shares, respectively	(7.9)	(9.3)
Accumulated other comprehensive loss	(285.1)	(218.9)
Total shareholders' equity	5,035.0	5,386.1

	$8,117.7	$8,458.3

See Notes to Consolidated Financial Statements.

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ROWAN COMPANIES PLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(In millions)

	Shares outstanding	Class A Ordinary Shares/ Common stock	Additional paid-in capital	Retained earnings	Treasury shares	Accumulated other comprehensive income (loss)	Total shareholders' equity
Balance, January 1, 2016	124.8	$ 15.7	$ 1,458.5	$ 3,509.8	$ (12.2)	$ (199.3)	$ 4,772.5
Net shares issued (acquired) under share-based compensation plans	0.7	0.3	(9.8)	—	5.0	—	(4.5)
Share-based compensation	—	—	20.4	—	—	—	20.4
Excess tax benefit from share-based awards	—	—	2.6	—	—	—	2.6
Retirement benefit adjustments, net of tax expense of $1.0	—	—	—	—	—	2.3	2.3
Net income	—	—	—	320.6	—	—	320.6
Balance, December 31, 2016	125.5	16.0	1,471.7	3,830.4	(7.2)	(197.0)	5,113.9
Net shares issued (acquired) under share-based compensation plans	0.8	—	(2.4)	—	(2.1)	—	(4.5)
Share-based compensation	—	—	19.3	—	—	—	19.3
Adoption of new accounting standard	—	—	—	206.6	—	—	206.6
Retirement benefit adjustments, net of tax expense of $0	—	—	—	—	—	(21.9)	(21.9)
Net income	—	—	—	72.7	—	—	72.7
Balance, December 31, 2017	126.3	16.0	1,488.6	4,109.7	(9.3)	(218.9)	5,386.1
Net shares issued (acquired) under share-based compensation plans	0.8	—	(5.1)	—	1.4	—	(3.7)
Share-based compensation	—	—	18.0	—	—	—	18.0
Adoption of new accounting standards (see Note 2)	—	—	—	51.1	—	(45.6)	5.5
Retirement benefit adjustments, net of tax benefit of $6.3	—	—	—	—	—	(23.5)	(23.5)
Other	—	—	—	(2.9)	—	2.9	—
Net loss	—	—	—	(347.4)	—	—	(347.4)
Balance, December 31, 2018	127.1	$ 16.0	$ 1,501.5	$ 3,810.5	$ (7.9)	$ (285.1)	$ 5,035.0

See Notes to Consolidated Financial Statements.

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ROWAN COMPANIES PLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Years ended December 31,		
	2018	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$(347.4)	$72.7	$320.6
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation and amortization	388.9	403.7	402.9
Equity in earnings of unconsolidated subsidiary	(10.3)	(0.9)	—
Deferred income taxes	(68.1)	24.7	(37.9)
Pension and other postretirement benefits (income) expense	(9.0)	12.5	15.0
Share-based compensation expense	24.0	29.0	34.6
Gain on sale of assets to unconsolidated subsidiary	(65.8)	(157.4)	—
Loss on disposals of property and equipment	12.1	9.4	8.7
Contingent payment derivative	—	0.1	(6.1)
Non-cash interest income from unconsolidated subsidiary (receipt in kind)	(12.0)	—	—
Asset impairment charges	—	—	34.3
Cash loss on extinguishment of debt	—	—	24.0
Other	8.1	1.5	3.7
Changes in current assets and liabilities:			
Receivables - trade and other	(7.2)	82.9	109.2
Prepaid expenses and other current assets	(6.1)	14.2	9.2
Accounts payable	2.8	1.9	(4.0)
Accrued income taxes	(12.3)	(3.8)	(3.4)
Other current liabilities	(25.1)	7.8	(27.2)
Other postretirement benefit claims paid	(1.4)	(18.4)	(7.9)
Contributions to pension plans	(24.2)	(29.3)	(22.5)
Deferred revenue	5.5	(112.8)	63.7
Net changes in other noncurrent assets and liabilities	(12.6)	(38.0)	12.7
Net cash provided by (used in) operating activities	(160.1)	299.8	929.6
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(169.2)	(100.6)	(117.6)
Purchase of rigs	(70.8)	—	—
Deposit on purchase of rigs	—	(7.7)	—
Investment in unconsolidated subsidiary	—	(30.0)	—
Contributions to unconsolidated subsidiary for note receivable	(271.3)	(357.7)	—
Proceeds from sale of assets to unconsolidated subsidiary	266.0	357.7	—
Repayments of note receivable from unconsolidated subsidiary	98.5	87.5	—
Proceeds from disposals of property and equipment	12.7	3.3	6.2
Net cash used in investing activities	(134.1)	(47.5)	(111.4)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	—	—	500.0
Reductions of long-term debt	—	(170.0)	(511.8)
Payment of debt extinguishment costs	—	—	(24.0)
Debt issue costs	(6.1)	—	(8.7)

Proceeds from exercise of share options	0.1	—	—
Shares repurchased for tax withholdings on vesting of restricted share units	(5.2)	(5.7)	(5.0)
Excess tax benefits from share-based compensation	—	—	2.6
Net cash used in financing activities	(11.2)	(175.7)	(46.9)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(305.4)	76.6	771.3
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	1,332.1	1,255.5	484.2
CASH AND CASH EQUIVALENTS, END OF PERIOD	$1,026.7	$1,332.1	$1,255.5

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 oil and gas industry, with a focus on ultra-deepwater drillships and high-specification and premium jack-up rigs. Many of our high specification jack-up rigs are also rated for operating in harsh environments. As of December 31, 2018, the Company operated in three segments: Deepwater, Jack-ups and ARO, the Company's 50/50 joint venture with Saudi Aramco. The Deepwater segment includes four ultra-deepwater drillships. The Jack-ups segment is composed of 21 self-elevating jack-up rigs and includes the impact of the various arrangements with ARO (see discussion below and Note 4). As of December 31, 2018, ARO owned a fleet of seven self-elevating jack-up rigs for operation in the Arabian Gulf for Saudi Aramco. ARO has plans to order up to 20 new jack-up rigs over the next 10 years. The Company contracts its drilling rigs, related equipment and work crews primarily on a day-rate basis in markets throughout the world, including the US GOM, Mexico, Central and South America, the U.K. and Norwegian sectors of the North Sea, the Middle East and the Mediterranean Sea.

The consolidated financial statements included herein are presented in USD and include the accounts of Rowan plc and its direct and indirect subsidiaries. Unless the context otherwise requires, the terms “Rowan,” and “Company” are used to refer to Rowan plc and its consolidated subsidiaries. Intercompany balances and transactions have been eliminated in consolidation.

Proposed Combination of Rowan Companies plc and Ensco plc

On October 7, 2018, the Company entered into a Transaction Agreement with Ensco, to effect a “merger-of-equals” transaction. The Transaction Agreement was amended as of January 28, 2019, pursuant to a Deed of Amendment No. 1 to a Transaction Agreement (the “Amendment”). In the Transaction Agreement, as amended, each of the issued and outstanding Class A ordinary shares of the Company will be exchanged (the “Transaction”) for 2.750 Class A ordinary shares of Ensco, each with a nominal value of $0.10 per share. The Transaction is being implemented by means of a court-sanctioned scheme of arrangement (the “Scheme”) under Part 26 of the U.K. Companies Act 2006 (provided that the parties reserve the right under the Transaction Agreement to effect the acquisition by way of a contractual takeover offer as defined in section 974 of the U.K. Companies Act 2006 in certain circumstances). The resulting new combined company will be renamed and trade under a new ticker symbol on the New York Stock Exchange.

The completion of the Transaction is subject to various closing conditions, including, among other things, (i) the sanction of a court-sanctioned scheme of arrangement by the High Court of Justice of England and Wales, (ii) the receipt of the required regulatory approval or elapse of the review period with respect thereto in the Kingdom of Saudi Arabia, (iii) the absence of legal restraints prohibiting or restraining the Transaction and (iv) the absence of any law or order reasonably expected to result in the dissolution of ARO, the sale or disposition of the Company’s interest in ARO, or the forfeiture or nationalization of the Company's interest in ARO or ARO’s assets. The Transaction is expected to close during the first half of 2019.

The Transaction Agreement contains certain termination rights for both Rowan and Ensco including, among other things: (i) by Rowan or Ensco, if the other party breaches or fails to perform any of its representations, warranties or covenants in the Transaction Agreement that cannot be or is not cured in accordance with the terms of the Transaction Agreement and such breach constitutes a “material adverse effect”, (ii) by Rowan, in the event that the board of directors of Ensco makes an Adverse Recommendation Change (as defined in the Transaction Agreement) or upon any “willful breach” by Ensco of the non-solicitation covenant and (iii) by Ensco, in the event that the board of directors of Rowan makes an Adverse Recommendation Change (as defined in the Transaction Agreement) or upon any “willful breach” by Rowan of the non-solicitation covenant. If the Transaction Agreement is terminated in accordance with clause (i), (ii) or (iii), then Rowan or Ensco, as the applicable terminating party, shall be required to pay the other a termination fee of $24.0 million (the “Termination Fee”).

Neither Rowan nor Ensco is permitted, among other things, to solicit, initiate or knowingly facilitate or knowingly encourage any inquiries regarding, or the making of any proposal or offer that constitutes, or could reasonably be expected to lead to, a takeover proposal or engage in or participate in any discussions or negotiations regarding any takeover proposal.

The Transaction Agreement contains customary representations, warranties and covenants for a transaction of this nature. The Transaction Agreement also contains customary mutual pre-closing covenants, including the obligation of Rowan and Ensco to conduct their respective businesses in the ordinary course of practice consistent with past practice and to refrain from taking certain specified actions without the consent of the other party.

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ARO Joint Venture

On November 21, 2016, Rowan and Saudi Aramco, through their subsidiaries, entered into a Shareholders' Agreement to create a 50/50 joint venture (the "Shareholders' Agreement") to own, manage and operate offshore drilling units in Saudi Arabia. The new entity, ARO, was formed in May 2017 with each of Rowan and Saudi Aramco contributing $25 million to be used for working capital needs. In addition, $5 million in transaction costs were incurred by Rowan and capitalized to the investment in ARO. ARO commenced operations on October 17, 2017 (see Note 4 for additional information).

On October 17, 2017, Rowan and Saudi Aramco amended the asset transfer and contribution agreements (the "Amended Agreements"), previously entered into in connection with the Shareholders' Agreement, to, among other things, modify and clarify the mechanics associated with the formation of ARO to provide for: (1) equal cash contributions to ARO by each of Rowan and Saudi Aramco, (2) the receipt of cash from both Rowan and Saudi Aramco in exchange for shareholder notes, (3) the subsequent sale of: (a) three rigs and related assets to ARO by Rowan in exchange for cash and (b) one rig and related assets to ARO by Saudi Aramco in exchange for cash, and (4) the distribution by ARO of excess cash in the amount of approximately $88 million to each party, to be applied as a repayment to each party's shareholder note, maintaining each party's 50% ownership interest in ARO following such asset sales. On October 17, 2017, these transactions were completed at which point the Company derecognized the related rig assets and began recording its interest in the ARO joint venture under the equity method of accounting. Pursuant to the terms of the Shareholders' Agreement and the Amended Agreements, Saudi Aramco also sold an additional rig to ARO in late December 2017 for cash.

On October 10, 2018, the Company concluded the sale of two additional jack-up rigs, the Scooter Yeargain and the Hank Boswell, to ARO. Transactions included (1) equal cash contributions to ARO by each of Rowan and Saudi Aramco, (2) the receipt of cash from both Rowan and Saudi Aramco in exchange for shareholder notes, (3) the subsequent sale of two such rigs to ARO by Rowan in exchange for cash, and (4) the distribution by ARO of excess cash in the amount of $95.3 million to each party, to be applied as a repayment to each party's shareholder note, maintaining each party's 50% ownership interest in ARO following such asset sales. By agreement of the parties, this transaction was effective October 1, 2018, at which point the Scooter Yeargain and Hank Boswell each were deemed to have commenced a new three-year contract with Saudi Aramco (see Note 15 for additional information).

Rigs purchased by ARO will receive contracts for an aggregate 15 years, renewed and re-priced every three years, provided that the rigs meet the technical and operational requirements of Saudi Aramco.

Rowan rigs in Saudi Arabia not selected for sale to the JV were managed by ARO until the end of their contracts with Saudi Aramco pursuant to a management services agreement that provided for a management fee equal to a percentage of revenue to cover overhead costs. As of December 31, 2018, nine Rowan Rigs were leased to ARO through bareboat charter agreements whereby substantially all operating costs will be borne by ARO. ARO contracts with the customer, Saudi Aramco, and directly receives related revenue. Two of the contracts between ARO and Saudi Aramco to which the leases are related, are expected to commence in the first half of 2019.

Anadarko Early Termination Revenue

During the quarter ended June 30, 2018, the Company recognized $27.8 million of revenue related to an early termination fee from Anadarko Petroleum Corporation ("Anadarko") pursuant to the Company's drilling contract for the drillship Rowan Resolute (the "Anadarko Contract"). Termination of the Anadarko Contract became effective on June 1, 2018. The early termination fee was a lump sum payment for the remainder of the term of the Anadarko Contract at a rate of $418,400 per day. The Anadarko Contract was originally scheduled to terminate on August 6, 2018.

Customer Contract Termination Amendment

On September 15, 2016, the Company amended its contract with Cobalt, for the drillship Rowan Reliance, which was scheduled to conclude on February 1, 2018. The amendment provided cash settlement payments to the Company totaling $95.9 million, that the drillship remain at its day rate of approximately $582,000 and that the drilling contract may be terminated as early as March 31, 2017. The Company received cash payments totaling $76.3 million in 2016 and received a final cash payment of $19.6 million during the first quarter of 2017. In addition, the amendment provided that if Cobalt continued its operations with the Rowan Reliance after March 31, 2017, the day rate would be reduced to approximately $262,000 per day for the remaining operating days through February 1, 2018 (subject to further adjustment thereafter). Cobalt International Energy, Inc., the parent of Cobalt, also committed to use the Company as its exclusive provider of comparable drilling services for a period of five years. As the Company had the obligation and intent to have the drillship or a substitute available through the pre-amended contract scheduled end date, in certain circumstances (including a 90 day notice of intent to use the rig prior to the original contract scheduled end date of February 1, 2018), the $95.9 million settlement was recorded as a deferred revenue liability at December 31, 2016. Amortization of deferred revenue began on April 1, 2017 and was fully amortized as of December 31, 2017 as Cobalt did not provide notice to the Company by November 2, 2017 (90 day notice of intent to use the rig).

Customer Contract Termination and Settlement

On May 23, 2016, the Company reached an agreement with FMOG and its parent company, FCX in connection with the drilling contract for the drillship Rowan Relentless ("FCX Agreement"), which was scheduled to terminate in June 2017. The FCX Agreement provided that the drilling contract be terminated immediately, and that FCX pay the Company $215 million to settle outstanding receivables and early termination of the contract, which was received in 2016. In addition, the Company received the right to receive up to two additional contingent payments from FCX, payable on September 30, 2017, of $10 million (the "First FCX Contingent Payment Provision") and $20 million (the "Second FCX Contingent Payment Provision" and, together with the First FCX Contingent Payment Provision, the "FCX Contingent Payments Provisions") depending on the average price of WTI crude oil over a 12-month period beginning June 30, 2016. The FCX Contingent Payments Provisions would have been due if the average price over the period was greater than $50 per barrel with respect to the First FCX Contingent Payment Provision and $65 per barrel with respect to the Second FCX Contingent Payment Provision ("Price Targets"). During the quarter ended June 30, 2016, the Company recognized $173.2 million in revenue for the Rowan Relentless, including $130.9 million for the cancelled contract value, $6.2 million for the fair value of the derivative associated with the FCX Contingent Payments Provisions, $5.6 million for previously deferred revenue related to the contract, and $30.5 million for operations through May 22, 2016. For additional information related to the FCX Contingent Payments Provisions see Note 7.

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 revenue and expenses during the reporting period. Actual results could differ from those estimates.

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's accounts receivable is stated at historical carrying value net of write-offs 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. Any allowance is based on historical and other factors that predict collectability, including write-offs, recoveries and the evaluation and monitoring of credit quality. No allowance for doubtful accounts was required at December 31, 2018 or 2017.

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The following table sets forth the components of Receivables - Trade and Other at December 31 (in millions):

	2018	2017
Trade	$231.7	$195.8
Income tax	12.0	8.0
Other	7.5	9.0
Total receivables - trade and other	$251.2	$212.8

Property and Depreciation

The Company provides 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. 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	2 to 25	0% to 10%	
Drillships:			
Hulls	35	10	%
Drilling equipment	2 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.

Expenditures for maintenance and repairs are charged to expense as incurred and totaled $139 million in 2018, $113 million in 2017 and $118 million in 2016.

Impairment of Long-lived Assets

The Company reviews 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, the Company determines recoverability by evaluating the undiscounted estimated future net cash flows based on projected day rates, operating costs, capital requirements and utilization of the asset under review. When the impairment of an asset is indicated, the Company measures the amount of impairment as the amount by which the asset's carrying amount exceeds its estimated fair value. The Company measures 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 the Company uses 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, the Company measures fair value based on equipment broker quotes, less anticipated selling costs, which are considered Level 3 inputs in the fair value hierarchy.

Subsequent to the October 2018 announcement of the proposed combination with Ensco, the Company conducted an impairment test of our assets; however, the test resulted in no impairment as the estimated undiscounted cash flows from the assets exceeded the assets' carrying values.

During the fourth quarter of 2017, the Company conducted an impairment test of its assets; however, the tests resulted in no impairment as the estimated undiscounted cash flows from the assets exceeded the assets' carrying values.

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In 2016, the Company conducted an impairment test of its assets and determined that the carrying values for five of its jack-up drilling units aggregating $43.6 million were not recoverable and as a result, the Company recognized a non-cash impairment charge of $34.3 million in 2016. The Company measured fair values using the income approach described above. The fair value estimates required the Company to use significant unobservable inputs, which are internally developed assumptions not observable in the market, including assumptions related to future demand for drilling services, estimated availability of rigs and future day rates, among others. The impairments recognized in 2016 on the jack-up rigs are included in jack-up operations in the segment information in Note 14. Impairment charges are included in Material charges and other operating items on the Consolidated Statements of Operations.

Share-based Compensation

The Company generally recognizes compensation cost for employee share-based awards on a straight-line basis over a 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 generally recognized over a minimum period of six months. Generally, compensation cost for employees who become retirement eligible after six months following the grant date but before the maximum service period which is typically 36 months is amortized over the period from the grant date to the date the employee meets the retirement eligibility requirements.

Fair value of RSAs and RSUs awarded to employees is based on the average of the high and low market price of the shares on the date of grant. Prior to January 1, 2017, compensation cost was recognized for awards that were expected to vest and were adjusted in subsequent periods if actual forfeitures differed from estimates. Pursuant to the adoption of ASU No. 2016-09 as of January 1, 2017, the Company no longer estimates forfeitures, but rather adjusts its compensation costs in the period that actual forfeitures occur.

Non-employee directors may annually elect to receive either Directors RSUs or Directors ND RSUs. Both Directors RSUs and Directors ND RSUs vest at the earlier of the first anniversary of the grant date or the next annual meeting of shareholders following the grant date. Directors ND RSUs are settled on the vesting date, while Director RSUs are not settled until the director terminates service from the Board. Both Directors ND RSUs and Directors RSUs are settled in cash, shares or a combination thereof at the discretion of the Company Compensation Committee. Compensation cost for both Director RSUs and Director ND RSUs are recognized over the service period which is up to one year. Directors RSUs and Directors ND RSUs are accounted for under the liability method of accounting, the fair value is based on the market price of the underlying shares 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 P-Units, in which the payment for 2018 awards is contingent on the Company's absolute TSR performance and relative TSR performance as measured against a group of companies selected by the Company Compensation Committee. For 2016 and 2017 awards, payment is contingent on the Company's TSR relative to the selected industry peer group. Fair value of P-Units is determined using a Monte-Carlo simulation model. P-Units may be settled in cash, shares or a combination thereof at the Company Compensation Committee's discretion. All P-Units are accounted for under the liability method of accounting. Compensation cost is generally recognized on a straight-line basis over the service period and is adjusted for changes in fair value at each report date through the end of the performance period. For P-Units granted in 2017 and 2018, the Company recognizes compensation cost on the accelerated method for those retirement eligible or who will become retirement eligible during the vesting period as such awards provide for pro-rata vesting rather than full vesting if a retirement eligible employee retires prior to the end of the 36 month service period.

Fair value of options is determined using the Black-Scholes option pricing model. The Company uses the simplified method for determining the expected life of options, 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 intends to share-settle options that are exercised and has therefore accounted for them as equity awards.

Fair value of 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 the Company's revenue is received in USD, which is the Company's functional currency. However, in certain countries in which the Company operates, local laws or contracts may require some payments to be received in the local currency. The Company is exposed to foreign currency exchange risk to the extent the amount of its monetary assets denominated in the foreign currency differs from its obligations in that foreign currency. In order to mitigate the effect of exchange rate risk, the Company attempts to limit foreign currency holdings to the extent they are needed to pay liabilities in the local currency.

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At December 31, 2018 and 2017, the Company held Egyptian pounds in the amount of $1.7 million and $2.8 million, respectively, of which $0.7 million and $2.2 million are classified as Other Assets on the Consolidated Balance Sheets. At December 31, 2018 and 2017, the Company held Angolan Kwanza in the amount of $2.0 million and $4.3 million, respectively, of which $1.7 million and $4.3 million are classified as Other Assets on the Consolidated Balance Sheets. See the "Assets and Liabilities Measured at Fair Value on a Recurring Basis" section of Note 8 for further information.

Non-USD transaction gains and losses are recognized in “other - net” on the Consolidated Statements of Income. The Company recognized net currency exchange losses of $3.4 million, $0.4 million and $9.7 million in 2018, 2017 and 2016, respectively. In 2016, the exchange loss was primarily due to the devaluation of the Egyptian pound.

Income Taxes

Rowan recognizes deferred income tax assets and liabilities for the estimated future tax consequences of differences between the financial statement and tax basis 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 has elected the portfolio approach to release the stranded or disproportionate income tax effect in Accumulated other comprehensive income (loss) related to the pension and employee benefits plans. Under the portfolio approach, the disproportionate tax effect created by the release of the U.S. valuation allowance is reclassified from Accumulated other comprehensive income (loss) to continuing operations when the Company terminates the related plans.

The Company has not provided deferred income taxes on certain undistributed earnings of non-U.K. subsidiaries. If facts and circumstances cause a change in expectations regarding future tax consequences, the resulting tax impact could have a material effect on the Company’s consolidated financial statements.

Principles of Consolidation

The consolidated financial statements include the Company's accounts and those of its wholly-owned subsidiaries. Intercompany balances and transactions have been eliminated in consolidation. Investments in operating entities where the Company has the ability to exercise significant influence, but where it does not control operating and financial policies are accounted for using the equity method. Significant influence generally exists if the Company has an ownership interest representing between 20% and 50% of the voting stock of the investee. Under the equity method of accounting, investments are stated at initial cost and are adjusted for subsequent additional investments and the Company's proportionate share of earnings or losses and distributions. Equity in earnings of ARO, in the consolidated statements of operations, reflects the Company's proportionate share of ARO's net income, including any associated affiliate taxes. See the Note 4 for additional details related to the Company's equity method investment.

Income (Loss) Per Common Share

Basic income (loss) per share is computed by dividing net income (loss) available to common shareholders by the weighted-average number of common shares outstanding during the period. Diluted income per share includes the additional weighted effect of dilutive securities outstanding during the period, which includes RSAs, RSUs, P-Units, share options and SARs granted under share-based compensation plans. The effect of share equivalents is not included in the computation for periods in which a net loss occurs because to do so would be anti-dilutive.

A reconciliation of net income (loss) for basic and diluted income (loss) per share is set forth below (in millions):

	2018	2017	2016
Net income (loss)	$(347.4)	$72.7	$320.6
Income allocated to non-vested share awards	—	0.1	1.5
Net income (loss) - adjusted for income allocated to non-vested share awards	$(347.4)	$72.8	$322.1

A reconciliation of shares for basic and diluted income (loss) per share is set forth below (in millions):

	2018	2017	2016
Average common shares outstanding	126.9	126.1	125.3
Effect of dilutive securities - share based compensation	—	1.6	1.0
Average shares for diluted computations	126.9	127.7	126.3

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Share options, SARs, RSAs, P-Units and RSUs granted under share-based compensation plans are anti-dilutive 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. Anti-dilutive shares, which could potentially dilute earnings per share in the future, are set forth below (in millions):

	2018	2017	2016
Share options and appreciation rights	$1.4	$1.5	$1.6
P-Units, RSAs and RSUs	5.7	2.1	0.9
Total potentially dilutive shares	$7.1	$3.6	$2.5

Revenue Recognition

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (ASC 606), which sets forth a global standard for revenue recognition and replaces most existing industry-specific guidance. ASC 606 requires an entity to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The Company adopted ASC 606, effective January 1, 2018, utilizing the modified retrospective approach and applied ASC 606 to all outstanding revenue contracts. The adoption of this standard did not have a material impact on our statements of operations or statements of cash flows.

In adopting ASC 606, the Company's revenue recognition differs from its historical revenue recognition pattern primarily as it relates to demobilization revenue. Such revenue, which was recognized upon completion of a contract under legacy accounting, is now estimated at contract inception and recognized over the term of the contract under the new guidance for customer contracts that have unconstrained demobilization provisions. Upon adoption of this standard as of January 1, 2018, the Company recognized a $5.5 million increase to retained earnings related to unconstrained demobilization provisions. Subsequently, during the first quarter of 2018, the Company received a $5.5 million cash payment for such demobilization related to one of the Company's contracts.

Typical contractual arrangements

The Company contracts its drilling rigs, related equipment and work crews primarily on a “day rate” basis. Under day rate contracts, the Company generally receives a fixed amount per day for each day it is performing drilling or related services. In addition, customers may pay all or a portion of the cost of moving equipment and personnel to and from the well site. Contracts generally range in duration from one month to multiple years or alternatively may be based on a set number of wells. Both duration types can include additional option periods at the discretion of the customer which can be at a set price or may be determined upon exercise of the option. The contractual day rate generally varies based on the status of the drilling operations and generally includes an operating rate, move rate, repair rate, force majeure rate, standby rate, or other fixed type of day rate specified in the contract. Other fees may be stipulated in the contract related to mobilization and demobilization of the rig, upfront preparation and/or upgrades, penalties, performance bonuses and reimbursements for third party charges or requested modifications. Termination clauses are also specified and generally allow the customer to cancel for lack of performance by the contractor with no related fee or for convenience for an early termination fee, typically calculated as a standby rate multiplied by the days remaining in the firm term in the contract often reduced by a specified percentage.

Performance obligations and transaction price

Customers generally contract for a comprehensive agreement to provide integrated services to operate a rig and drill a well. Drillers are seen by the operator as the overseer of all services and are compensating the driller to provide that entire suite of services. In identifying performance obligations, ASC 606 series guidance states that a contract may contain a single performance obligation composed of a series of distinct goods or services if 1) each distinct good or service is substantially the same and would meet the criteria to be a performance obligation satisfied over time and 2) each distinct good or service is measured using the same method as it relates to the satisfaction of the overall performance obligation. The Company determined that the delivery of day rate drilling services is within the scope of the series guidance as both criteria noted above are met. Specifically, 1) each distinct increment of service (i.e. hour available to drill) that the driller promises to transfer represents a performance obligation that would meet the criteria for recognizing revenue over time, and 2) the driller would use the same method for measuring progress toward satisfaction of the performance obligation for each distinct increment of service in the series.

Consideration for activities that are not distinct within the scope of our contracts, such as mobilization, demobilization and upgrade/modification, and do not align with a distinct time increment within the contract term are allocated across the single performance obligation and are recognized over the expected recognition period in proportion to the passage of each hour available to drill. Consideration for activities which align with a distinct time increment within the contract term is recognized in the period when the services are performed.

The transaction price for a drilling contract is based on the amount of consideration the Company expects to be entitled for providing drilling services over the specified term and includes both fixed amounts and unconstrained variable amounts. Typically, at contract commencement, the only fixed/known consideration components of a drilling contract are negotiated lump-sum amounts to be received for reimbursement of costs incurred for mobilization, demobilization (where it is contractually guaranteed) and/or rig modifications or upgrades. The Company estimates variable consideration using the expected value method and includes the amount in transaction price to the extent it is not constrained. Variable consideration is generally constrained if it is probable that a significant reversal in the amount of cumulative revenue recognized will occur when the uncertainty associated with the variable consideration is subsequently resolved.

Recognition of revenue

Drilling services are consumed as the services are performed and generally enhance a well site which the customer/operator controls. Work performed on a well site does not create an asset with an alternative use to the contractor since the well/asset being worked on is owned by the customer. Therefore, the Company's measure of progress for a drilling contract is hours available to drill over the contracted duration. This unit of measure is representative of an output method as described in ASC 606. The following chart details the types of fees found in a typical drilling contract and the related recognition method under ASC 606:

Fee type	Revenue Recognition
Day rate	Recognition is based on the day rates earned/invoiced as it relates to the level of service provided for each fractional-hour throughout the contract.
Mobilization and upgrade/modification	Revenue (both lump-sum and day rate amounts) is estimated at contract inception and included in the transaction price to be recognized over the expected recognition period.
Demobilization	Unconstrained demobilization revenue (both lump-sum and day rate amounts) is estimated at contract inception, included in the transaction price, and recognized over the expected recognition period in proportion to the passage of each hour available to drill.
Bonuses and penalty	Unconstrained bonus and/or penalty revenue is estimated at contract inception and included in the transaction price. Amounts are recognized in the period corresponding to the distinct hourly increment(s) of service provided (i.e. the specific period which the bonus or penalty relates to).
Reimbursement	Recognized (gross of costs incurred), at the point the product or service is consumed, and in the amount billed to the customer.

Future performance obligation and financing arrangements

Due to the recognition of day rate, as described above, the Company's primary future promised service relates to unconstrained demobilization. Under ASC 606 the Company recognizes unconstrained demobilization revenue over the life of the contract whereas in a typical drilling contract the demobilization, and the resulting cash payment for demobilization, does not occur until the end of the contract. At December 31, 2018, the Company had a contract asset of $5.5 million for unconstrained demobilization revenue (see Note 3) related to the Company recognizing $5.5 million in unconstrained demobilization revenue into income during the year ended December 31, 2018. We expect to recognize the remaining $5.9 million of our total estimated $11.4 million of unconstrained demobilization into revenue in 2019. We have applied the optional exemption afforded in ASU No. 2014-09 and have not disclosed the variable consideration related to the estimated future day rate revenues. Upon adoption of this standard as of January 1, 2018, the Company recognized a $5.5 million increase to retained earnings related to unconstrained demobilization provisions. Subsequently, during the first quarter of 2018, the Company received a $5.5 million cash payment for such demobilization related to one of the Company's contracts.

Under ASC 606, a significant financing component may exist, regardless of whether the promise is explicitly stated or implied by the payment terms stipulated in a contract, where there is a separation between the timing of services provided and the timing of payment in contracts with terms exceeding one year. Generally, a typical drilling contract stipulates for billings on a monthly basis and payment terms vary by contract and customer but are customarily paid within 90 days. It is rare for a drilling contract to explicitly address a financing component and payments of up-front

fees correspond to cash outlays which Rowan must undertake in order to complete a given drilling contract.
Recently Adopted Accounting Pronouncements - In addition to Revenue from Contracts with Customers (ASC 606) (see "Revenue Recognition" above), the Company has recently adopted the following accounting pronouncements:

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Statement of Cash Flows - In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows (ASC 230): Classification of Certain Cash Receipts and Cash Payments, which provides guidance on eight cash flow classification issues with the objective of reducing differences in practice. As of January 1, 2018, the Company adopted this guidance on a retrospective basis with no material impact on its consolidated financial statements.

Statement of Cash Flows Restricted Cash - In November 2016, the FASB issued ASU No. 2016-18, Statement of Cash Flows (ASC 230): Restricted Cash, which requires restricted cash to be presented with cash and cash equivalents in the statement of cash flows. The changes in restricted cash and restricted cash equivalents during the period should be included in the beginning and ending cash and cash equivalents balance reconciliation on the statement of cash flows. When cash, cash equivalents, restricted cash or restricted cash equivalents are presented in more than one line item within the statement of financial position, an entity shall calculate a total cash amount in a narrative or tabular format that agrees with the amount shown on the statement of cash flows. Details on the nature and amounts of restricted cash should also be disclosed. As of January 1, 2018, the Company adopted this guidance on a retrospective basis with no impact on its consolidated financial statements.

Other Income - In February 2017, the FASB issued ASU No. 2017-05, Other Income - Gains and Losses from the Derecognition of Nonfinancial Assets (“ASU 2017-05”), which clarifies the scope of the original guidance within Subtopic 610-20 that was issued in connection with ASU 2014-09, which provides guidance for recognizing gains and losses from the transfer of nonfinancial assets in contracts with non-customers. ASU 2017-05 also adds guidance for partial sales of nonfinancial assets. As of January 1, 2018, the Company adopted this guidance on a modified retrospective basis concurrently with ASC 606. This adoption had no impact on the Company's consolidated financial statements.

Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost - In March 2017, the FASB issued ASU No. 2017-07, Compensation - Retirement Benefits (ASC 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, which requires entities to present the service cost component of the net periodic benefit cost in the same income statement line item as other employee compensation costs. The other components of net benefit cost, including interest cost, expected return on plan assets, amortization of prior service cost/credit and actuarial gain/loss, and settlement and curtailment effects, are to be presented outside of any subtotal of operating income. Entities will have to disclose the line(s) used to present the other components of net periodic benefit cost, if the components are not presented separately in the income statement. The ASU also allows only the service cost component to be eligible for capitalization. As of January 1, 2018, the Company adopted this guidance on a retrospective basis with no material impact on its consolidated financial statements.

Accumulated Other Comprehensive Income – In February 2018, the FASB issued ASU No. 2018-02, Income Statement - Reporting Comprehensive Income (ASC 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income, which allow a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act of 2017. As permitted under this ASU, the Company elected early adoption of this ASU as of January 1, 2018 and recorded a $45.6 million increase to Retained earnings as a reclassification from Accumulated other comprehensive income. The stranded tax effects are for the U.S. income tax rate reduction recognized in the Consolidated Statements of Operations for the year ended December 31, 2017 for the deferred tax asset associated with employee benefit plans.

Accounting Pronouncements - to be Adopted

Lease Accounting – In February 2016, the FASB issued ASU No. 2016-02, Leases (ASC 842): Amendments to the FASB ASC, which requires an entity to recognize lease assets and lease liabilities on the balance sheet and provide enhanced disclosures. Leases will continue to be classified as either finance (capital lease under ASC 840) or operating. Based on the original guidance, lessees and lessors would have been required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach, including a number of optional practical expedients that entities may elect to apply. In July 2018, the FASB issued ASU No. 2018-11, Leases (ASC 842): Targeted Improvements, which provides entities with an option to apply the guidance prospectively, instead of retrospectively, and allows for other classification provisions, as described below. ASC 842 is effective for annual and interim periods beginning after December 15, 2018. The Company adopted ASC 842 effective January 1, 2019 using a modified retrospective method and has elected to not retrospectively adjust amounts presented for prior periods. In addition, we will take advantage of various practical expedients, provided by the ASC 842, including:

- use of the transition package of practical expedients which, among other things, allows us to carryforward the historical lease classification for existing leases;
- making an accounting policy election that will keep leases with an initial term of 12 months or less off the balance sheet; and
- not separating non-lease components from lease components for all classes of underlying lease assets.

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Prior to the issuance of ASU No. 2018-11, the Company preliminarily determined that its drilling contracts contained a lease component, and the adoption would require the Company to separately recognize revenue associated with the lease and services components. In July 2018, the FASB issued ASU No. 2018-11, which provides a practical expedient that allows entities to combine lease and non-lease components where the revenue recognition pattern is the same and where the lease component, when accounted for separately, would be considered an operating lease. In connection with the adoption of ASC 842, the Company has been working with the International Association of Drilling Contractors Accounting Sub-committee and has determined that its drilling contracts (excluding bareboat charter contracts with ARO where the Company provides the rig without providing any drilling services) are predominantly service contracts in nature and will therefore account for these contracts under ASC 606.

The adoption of ASC 842 will have an impact on our consolidated balance sheets and disclosures contained in our notes to consolidated financial statements. Based on our portfolio of leases where we are the lessee, we will recognize between $10 million and $20 million of right of use lease assets and lease liabilities on our balance sheet upon adoption, primarily relating to real estate and other miscellaneous equipment. We do not expect the adoption of ASC 842 to have a material impact on our consolidated statements of operations or cash flows.

Financial Instruments – In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments - Credit Losses (ASC 326): Measurement of Credit Losses on Financial Instruments, which amends the FASB's guidance on the impairment of financial instruments. The ASU adds to US GAAP an impairment model that is based on expected losses rather than incurred losses. Under the new guidance, an entity recognizes as an allowance its estimate of expected credit losses. The Company will be required to adopt the amended guidance in annual and interim reports beginning January 1, 2020, with early adoption permitted for fiscal years beginning after December 15, 2018. The Company is in the process of evaluating the impact this amendment will have on its consolidated financial statements.

Fair Value Measurement - In August 2018, the FASB issued ASU No. 2018-13, Fair Value Measurement (ASC 820): Disclosure Framework – Changes to the Disclosure Requirements for Fair Value Measurement, which removes, modifies and adds certain disclosure requirements on fair value measurements including (i) removal of the requirements to disclose the amounts and reasons for as well as the policy for timing of transfers between Level 1 and Level 2 as well as descriptions of valuation processes used for Level 3 fair value measurements; (ii) certain modifications including clarification that the measurement uncertainty disclosure is to communicate information about the uncertainty in measurement as of the reporting date and; (iii) add disclosures related to changes in unrealized gains and losses for the period included in other comprehensive income (loss) for recurring Level 3 fair value measurements held at the end of the reporting period as well as disclosures for the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements. The Company will be required to adopt the amended guidance in annual and interim reports beginning January 1, 2020, with early adoption permitted. Adoption is required to be applied prospectively with respect to the amendments on changes in unrealized gains and losses, range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements and narrative description of measurement uncertainty. All other amendments are to be applied retrospectively to all periods presented. The Company is in the process of evaluating the impact this amendment will have on its consolidated financial statements.

Defined Benefit Plans - In August 2018, the FASB issued ASU No. 2018-14, Compensation – Retirement Benefits – Defined Benefit Plans – General (Subtopic 715-20): Disclosure Framework – Changes to the Disclosure Requirements for Defined Benefit Plans, which modifies the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. The Company will be required to adopt the amended guidance in annual and interim reports beginning January 1, 2021, with early adoption permitted. Adoption is required to be applied on a retrospective basis to all periods presented. The Company is in the process of evaluating the impact this amendment will have on its consolidated financial statements.

Internal Use Software - In August 2018, the FASB issued ASU No. 2018-15, Intangibles - Goodwill and Other - Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract (a consensus of the FASB Emerging Issues Task Force), which aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software (and hosting arrangements that include an internal-use software license). The Company will be required to adopt the amended guidance in annual and interim reports beginning January 1, 2020, with early adoption permitted. Adoption may be applied retrospectively or prospectively to implementation costs incurred after the date of adoption. The Company is in the process of evaluating the impact this amendment will have on its consolidated financial statements.

Note 3 – Contract Assets, Deferred Contract Costs Asset and Contract Liabilities

Costs incurred for mobilization, upfront modifications/upgrades and contract preparation are direct costs incurred to fulfill contracts and are expensed over the expected recognition period in the event they are deemed recoverable or in the case of capital upgrades or capital modifications such costs are capitalized and depreciated in accordance with the Company's fixed asset capitalization

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policy. Such costs other than those capitalized as fixed assets are deferred and recorded as deferred contract costs. Demobilization contract assets reflect the amount of unconstrained demobilization revenue recognized for which the Company's entitlement to invoice the customer is dependent on future performance.

The following table sets forth deferred contract costs, demobilization contract assets and deferred revenue on the Consolidated Balance Sheets (in millions):

		December 31,	
	Balance Sheet Classification	2018	2017
Deferred Contract Costs and Demobilization Contract Assets			
Current	Prepaid expenses and other current assets	$ 8.7	$ 2.8
Noncurrent	Other assets	0.4	—
		$ 9.1	$ 2.8
Deferred Revenue - Contract Liabilities			
Current	Deferred revenue	$ 16.7	$ 1.1
Noncurrent	Other liabilities	19.1	0.5
		$ 35.8	$ 1.6

Presented in the table below are the changes in deferred contract costs during the year ended December 31 (in millions):

	2018
Deferred Contract Costs Asset	
Beginning balance	$ 2.8
Plus: contractual additions	8.9
Less: amortization	8.1
Ending balance	$ 3.6

Presented in the table below are the changes in contract assets (see Note 2) during the year ended December 31 (in millions):

	2018
Contract Assets - Demobilization	
Beginning balance	$ —
Plus: contractual additions	5.5
Ending balance	$ 5.5

Presented in the table below are the changes in deferred revenue during the year ended December 31 (in millions):

	2018
Deferred Revenue - Deferred mobilization and upgrade/modification revenue	
Beginning balance	$ 1.6
Plus: contractual additions (1)	51.0
Less: amortization	16.8
Ending balance	$ 35.8

(1) Includes $28.6 million of deferred revenue related to capital expenditures for the Bess Brants, Earnest Dees, EXL I and EXL IV (all leased to ARO) to be received as reimbursement from ARO. A receivable of $28.6 million is included in Receivables - trade and other on the Consolidated Balance Sheet at December 31, 2018.

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Estimated future amortization at December 31, 2018 of our deferred revenue and deferred contract costs to be recognized over the expected recognition period is set forth in the following table (in millions):

	2019	2020	2021	2022	Total
Amortization of deferred revenue	$16.7	$9.6	$8.5	$1.0	$35.8
Amortization of deferred contract costs	3.2	0.2	0.2	—	3.6

No impairment losses were recognized on contract assets during the year ended December 31, 2018.

NOTE 4 – Equity Method Investments and Variable Interest Entities

On November 21, 2016, Rowan and Saudi Aramco, through their subsidiaries, entered into a Shareholders' Agreement to create a 50/50 joint venture, known as ARO (see Note 1). ARO commenced operations on October 17, 2017 and owns, manages and operates offshore drilling units in Saudi Arabia. The Company accounts for its interest in ARO using the equity method of accounting and only recognizes its portion of equity earnings in the Company's consolidated financial statements. ARO is a variable interest entity; however, the Company is not the primary beneficiary and therefore does not consolidate ARO. The Company's judgment regarding the level of influence over ARO included considering key factors such as: each company's ownership interest, representation on the board of managers of ARO, ability to direct activities that most significantly impact ARO's economic performance, as well as the ability to influence policy-making decisions.

Summarized financial information

Summarized financial information for ARO, as derived from ARO's financial statements, is as follows (in millions):

	Year ended December 31, 2018	October 17, 2017 to December 31, 2017
Revenue	$ 348.8	$ 48.6
Direct operating costs (excluding items below)	194.0	22.2
Depreciation and amortization	67.4	12.9
Selling, general and administrative	27.0	6.1
(Gain) loss on disposals of property and equipment	1.4	(0.1)
Income from Operations	59.0	7.5
Interest expense	(26.2)	(4.2)
Provision for income taxes	12.3	1.6
Net Income	$ 20.5	$ 1.7
Rowan's equity in earnings from ARO	$ 10.3	$ 0.9

	December 31, 2018	December 31, 2017
Current assets	$ 348.9	$ 108.6
Non-current assets	727.0	459.7
Total assets	$ 1,075.9	$ 568.3
Current liabilities	$ 112.2	$ 29.2
Non-current liabilities	949.1	545.1
Total liabilities	$ 1,061.3	$ 574.3

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Related party transactions

In October 2017 and October 2018, the Company contributed cash to ARO in exchange for a 10-year shareholder note receivable from ARO, at a stated interest rate of LIBOR plus two percent (See Note 1). Interest is being recognized as a part of Interest income in the Company's Consolidated Statements of Operations and totaled approximately $12.9 million for the year ended December 31, 2018, and $2.1 million for the period from October 17, 2017 to December 31, 2017. Interest was received in kind and accreted to the note in 2018.

Activity related to the shareholder note receivable (in millions):

Long-term note receivable from unconsolidated subsidiary	2018	2017	
Beginning Balance January 1,	$270.2	$—	
Origination	271.3	357.7	See Note 1
Repayments [2]	(98.5)	(87.5)	See Note 1
Interest in kind	12.0	—	
Other	1.0	1.1	
Total	456.0	271.3	
Less: Current Portion [1]	—	1.1	
Ending Balance December 31,	$456.0	$270.2	

[1] Included in Receivables - trade and other on the Company's Consolidated Balance Sheet.

[2] Includes excess cash distributed back to Rowan in October of 2018 and October 2017 (See Note 1).

In conjunction with the establishment of ARO, the Company entered into a series of agreements with ARO including: a Transition Services Agreement, Secondment Agreement and Lease Agreements. There is also an agreement between the Company and ARO, pursuant to which ARO will reimburse the Company for certain Capital Expenditures related to four rigs leased to ARO (See Note 3). Pursuant to these agreements the Company, or its seconded employees, will provide various services to ARO, and in return, the Company is to be provided remuneration for those services. From time to time Rowan may sell equipment or supplies to ARO. Revenue and other amounts recognized by Rowan related to these agreements and transactions is as follows (in millions):

	Year ended December 31, 2018	October 17, 2017 to December 31, 2017
Secondment Revenue - Jack-ups	$ 55.9	$ 9.2
Lease and related Revenue - Jack-ups	24.4	—
Transition Services Revenue - Unallocated	33.8	7.4
Sales of supplies - Jack-ups	5.0	0.5
Total Revenue received from ARO	$ 119.1	$ 17.1
Reimbursement of preparation costs [a]	$ —	$ 1.6
Proceeds from equipment sales to ARO [b]	10.8	1.0

[a] For the year ended December 31, 2017, the reimbursement resulted in a reduction in expense of $1.3 million and a $0.3 million decrease to Prepaid expenses and other current assets. The entire $1.6 million was included in Receivables - trade and other at December 31, 2017 for the amount to be reimbursed.

[b] A gain of $1.2 million for the year ended December 31, 2018 was recognized in Loss on disposals of property and equipment on the Consolidated Statements of Operations. There was no gain or loss

recognized for the year ended December 31, 2017. $3.5 million and $1.0 million is included in Receivables - trade and other as of December 31, 2018 and 2017, respectively, for the $10.8 million and $1.0 million purchase price, respectively.

Total Accounts receivable from ARO totaled approximately $68.8 million and $17.3 million as of December 31, 2018 and 2017, respectively, and are included in Receivables - trade and other on the Consolidated Balance Sheets.

The Company also entered into a Rig Management Agreement pursuant to which ARO provided certain rig management services for Rowan's rigs while they were contracted with Saudi Aramco and the Company compensated ARO for the services in which

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they provided to Rowan. There were no rigs managed by ARO at December 31, 2018. For the year ended December 31, 2018 and the period from October 17, 2017 to December 31, 2017, the Company recognized $33.5 million and $7.8 million, respectively, in Direct operating cost in the Consolidated Statements of Operations related to these rig management services. Additionally, ARO may sell equipment or supplies to Rowan or purchase such for Rowan, in which case ARO is provided reimbursement. For the year ended December 31, 2018 and the period from October 17, 2017 to December 31, 2017, the Company recognized $4.4 million and $0.6 million, respectively, in Direct operating cost in the Consolidated Statements of Operations related to these transactions. Additionally, during 2018 the Company purchased equipment from ARO for $6.4 million, of which $1.5 million was included in accounts payable as accrued and unpaid capital expenditures as of December 31, 2018. The Company had $2.4 million included in accounts payable as accrued and unpaid capital expenditures as of December 31, 2017.

Accounts payable to ARO totaled approximately $6.1 million and $10.8 million as of December 31, 2018 and 2017, respectively.

The following summarizes the total assets and liabilities as reflected in the Company's consolidated balance sheets as well as the Company's maximum exposure to loss related to ARO (in millions). Generally, the Company's maximum exposure to loss is limited to its 1) equity investment in the joint venture, 2) outstanding note receivable and 3) any receivable to the Company for services it provides to the joint venture, reduced by payables for services which the Company owes to ARO.

	December 31, 2018	December 31, 2017
Total assets	$ 566.0	$ 319.5
Total liabilities	6.1	10.8
Maximum exposure to loss	$ 559.9	$ 308.7

NOTE 5 – ACCRUED LIABILITIES

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

	2018	2017
Pension and other postretirement benefits	$16.8	$27.0
Compensation and related employee costs	45.0	69.0
Interest	34.0	32.0
Income taxes	7.1	15.4
Other	10.5	15.7
Total accrued liabilities	$113.4	$159.1

NOTE 6 – LONG-TERM DEBT

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

	2018	2017
7.875% Senior Notes, due August 2019 ($201.4 million principal amount; 8.0% effective rate)	$201.2	$200.9
4.875% Senior Notes, due June 2022 ($620.8 million principal amount; 4.7% effective rate)	623.8	624.6
4.75% Senior Notes, due January 2024 ($398.1 million principal amount; 4.8% effective rate)	396.3	395.9
7.375% Senior Notes, due June 2025 ($500 million principal amount; 7.4% effective rate)	497.8	497.5
5.4% Senior Notes, due December 2042 ($400 million principal amount; 5.4% effective rate)	395.3	395.1
5.85% Senior Notes, due January 2044 ($400 million principal amount; 5.9% effective rate)	396.5	396.3
Total carrying value	2,510.9	2,510.3
Current portion [(1)]	201.2	—
Carrying value, less current portion	$2,309.7	$2,510.3

[(1)] Current portion of long-term debt at December 31, 2018 included the 7.875% Senior Notes due in August 2019.

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The following is a summary of scheduled long-term debt maturities by year, as of December 31, 2018 (in millions):

2019	$201.4
2020	—
2021	—
2022	620.8
2023	—
Thereafter	1,698.1
	$2,520.3

Revolving Credit Facility

On May 22, 2018, the Company amended and restated its Existing Credit Agreement, which permitted, among other things, entry into the New Credit Agreement and a non-pro rata commitment reduction (the "Commitment Reduction") for each lender under the Existing Credit Agreement who became a lender under the New Credit Facility. The Existing Credit Agreement further provided for, among other things; (i) the reduction of the Existing Credit Agreement's letter of credit subfacility to $0, (ii) the Commitment Reduction and (iii) the resignation of Wells Fargo as administrative agent and appointment of Wilmington Trust, National Association, as successor administrative agent under the Existing Credit Agreement. The Commitment Reduction resulted in the lenders under the New Credit Facility having no commitments under the Existing Credit Facility and reduced the aggregate principal amount of commitments under the Existing Credit Facility to $310.7 million. Of the $310.7 million of availability under the Existing Credit Facility, $60.0 million of the availability matures on January 23, 2019, $150.7 million of the availability matures on January 23, 2020, and the remaining $100.0 million of the availability matures on January 23, 2021. Availability under the Existing Credit Facility was $310.7 million at December 31, 2018, as no amounts were drawn.

Advances under the Existing Credit Facility bear interest at LIBOR or base rate as specified in the Existing Credit Agreement plus an applicable margin, which is dependent upon the Company's credit ratings. The applicable margins for LIBOR and base rate advances range from 1.125% - 2.0% and 0.125% - 1.0%, respectively. The Company is also required to pay a commitment fee on undrawn amounts of the Existing Credit Facility, which ranges from 0.125% to 0.35%, depending on the Company's credit ratings.

The Existing Credit Facility requires the Company to maintain a total debt-to-capitalization ratio of less than or equal to 60%. The Company's consolidated debt to total capitalization ratio at December 31, 2018, was 33%. Additionally, the Existing Credit Facility has customary restrictive covenants that, including others, restrict the Company's ability to incur certain debt and liens, enter into certain merger and acquisition agreements, sell, transfer, lease or otherwise dispose of all or substantially all of the Company's assets and substantially change the character of the Company's business from contract drilling.

Availability under the New Credit Facility is $955.0 million, which matures on May 22, 2023; provided, however, that if the Company's 2022 Notes are not refinanced in full on or prior to February 1, 2022, the maturity date will be February 1, 2022. The New Credit Agreement currently provides for a swingline subfacility in the amount of $50 million, and a letter of credit subfacility in the amount of $129 million, with the ability to increase such amounts (subject to certain lenders agreeing to become issuers of letters of credit following the closing date). Borrowings under the New Credit Facility may be used for working capital and other general corporate purposes. The New Credit Agreement also includes restrictions on borrowings if, after giving effect to any such borrowings and the application of the proceeds thereof, the aggregate amount of the Company's cash-on-hand, subject to certain exceptions, would exceed $200 million. As of December 31, 2018, no amounts were outstanding and $6.8 million in letters of credit had been issued under the New Credit Facility leaving remaining availability of $948.2 million.

Subject to the successful procurement of additional commitments from new or existing lenders, borrower may elect to increase the maximum amount available under the New Credit Facility from $955.0 million by an additional amount not to exceed $250 million.

Revolving borrowings under the New Credit Facility bear interest, at the Company's option, at either (a) the sum of LIBOR plus a margin ranging between 2.75% to 4.25%, depending on the credit rating of the Company, or (b) the sum of a base rate specified in the New Credit Agreement, plus a margin ranging between 1.75% to 3.25%, depending on the credit rating of the Company. The Company is also required to pay a commitment fee on undrawn amounts of the New Credit Agreement, which ranges from 0.375% to 0.7% depending on the Company's credit rating.

The New Credit Agreement contains certain financial covenants applicable to the Company, including: (i) a covenant restricting debt to total tangible capitalization to not greater than 55% at the end of each fiscal quarter, (ii) a minimum liquidity requirement of $300.0 million, (iii) a covenant that the ratio of the net book value of the Company's drilling rigs either marketed or under

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contract with a customer to the sum of commitments under the New Credit Agreement, the commitments under the Existing Credit Agreement plus any other indebtedness of the borrower and guarantors (other than unsecured intercompany indebtedness that is contractually subordinated to the obligations under the New Credit Agreement) that is secured by a lien, guaranteed by, or has an obligor who is a subsidiary of Rowan plc, in each case, that directly owns or operates a drilling rig, is not less than 3:00 to 1:00 at the end of each fiscal quarter (the "Marketed Rig Value Ratio") and (iv) a covenant that the ratio of (A) the net book value of the Company's drilling rigs, subject to certain exclusions, that are directly wholly owned by Rowan plc and its subsidiaries who are borrowers or guarantors under the New Credit Facility to (B) the net book value of all drilling rigs owned by the Company and certain of its local content affiliates, is not less than 80% at the end of each fiscal quarter (the "Guaranteed Rig Value Ratio"). As of December 31, 2018, the Company was in compliance with each of the financial covenants under the New Credit Agreement as follows:

Financial covenant	Min/Max Requirement	Value as of December 31, 2018
Debt to capitalization Ratio	55 %	33 %
Liquidity (in millions)	$ 300.0	$2,285.6
Marketed Rig Value Ratio	3.00	4.10
Guaranteed Rig Value Ratio	80 %	86 %

The New Credit Agreement also contains additional covenants generally applicable to the Company and its subsidiaries that the Company considers usual and customary for an agreement of this type, including compliance with laws (including environmental laws, ERISA and anti-corruption and sanctions laws), delivery of quarterly and annual financial statements, maintenance and operation of property, restrictions on investments, asset sales, the incurrence of liens and indebtedness, mergers and other fundamental changes, restricted payments, repurchases and redemptions of indebtedness and equity, sale and leaseback transactions and transactions with affiliates. Borrowings under the New Credit Facility are subject to acceleration upon the occurrence of events of default that the Company considers usual and customary for an agreement of this type.

Debt Reductions

During the first half of 2016, the Company paid $45.2 million in cash to retire $47.9 million aggregate principal amount of the 2017 Notes and the 2019 Notes, and recognized a $2.4 million gain on early extinguishment of debt.

In December 2016, the Company commenced cash tender offers for $750 million aggregate principal amount of the Subject Notes issued by the Company (the "Tender Offers"). The Tender Offers expired on January 3, 2017; however, there was also an early tender expiration on December 16, 2016, which provided for an early tender premium. Subject Notes validly tendered and accepted for purchase prior to the early tender expiration time on December 16, 2016, received tender offer consideration plus an early tender premium. As a result of the Tender Offers, in December 2016, the Company paid $490.5 million to repurchase $463.9 million aggregate principal amount of outstanding Subject Notes, consisting of $265.5 million of the 2017 Notes, $186.7 million of the 2019 Notes, $9.8 million of the 2022 Notes and $1.9 million of the 2024 Notes, and recognized a $33.6 million loss on the early extinguishment of debt which included approximately $5.9 million of bank and legal fees.

On December 19, 2016, Rowan plc, as guarantor, and its 100% owned subsidiary, RCI, as issuer, completed the issuance of $500 million aggregate principal amount of the 2025 Notes at a price of 100% of the principal amount. The Company used the net proceeds of the offering, approximately $492 million, along with cash on hand, to fund the repurchase of Subject Notes pursuant to the Tender Offers. $5.3 million of the cash paid to the underwriting banks in the form of the underwriters discount and structuring fee was expensed and included in the $33.6 million loss on early extinguishment of debt related to the Tender Offers. Interest on the 2025 Notes is payable on June 15 and December 15 of each year.

In January 2017, at the expiration of the Tender Offers, the Company paid $32.8 million to repurchase an additional $34.6 million aggregate principal amount of outstanding Subject Notes, consisting of $0.1 million of the 2017 Notes,

$0.9 million of the 2019 Notes and $33.6 million of the 2022 Notes. The Company recognized a $2.0 million gain on the early extinguishment of debt.

On January 9, 2017, the Company called for redemption $92.1 million aggregate principal amount of the 2017 Notes that remained outstanding and on February 8, 2017, the Company paid $94.0 million to redeem such notes and recognized a $2.1 million loss on early extinguishment of debt.

In the second quarter of 2017, the Company paid $33.5 million in cash to retire $35.8 million aggregate principal amount of the 2022 Notes and recognized a $2.4 million gain on early extinguishment of debt.

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In July 2017, the Company paid $7.0 million in cash to retire $6.5 million aggregate principal amount of the 2019 Notes and recognized a $0.5 million loss on early extinguishment of debt.

Debt Guarantee and Other Provisions

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 Existing 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). The Senior Notes are fully and unconditionally guaranteed on a senior and unsecured basis by Rowan plc. (see Note 18)

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 2025 Notes contain a provision whereby upon a change of control repurchase event, as defined in the indenture governing the 2025 Notes, the Company may be required to make an offer to repurchase all outstanding notes at a price in cash equal to 101% of the aggregate principal amount of the notes repurchased, plus any accrued and unpaid interest to the repurchase date. Otherwise, the 2025 Notes contain substantially the same provisions as the Company’s other Senior Notes.

Other provisions of the Company's 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, 2018.

NOTE 7 – DERIVATIVES

In 2016, the Company determined that the FCX Contingent Payments Provisions resulting from the contract termination with FMOG (See Note 1) were freestanding financial instruments and that they each met the criteria of a derivative instrument. The FCX Contingent Payments Provisions were initially recorded to revenue at a fair value of $6.2 million on May 23, 2016, and were revalued at each reporting date with changes in the fair value reported as non-operating income or expense. The fair value of the FCX Contingent Payments Provisions was determined using a Monte Carlo simulation (see Note 8). In January 2017, the Company and FCX settled the First FCX Contingent Payment Provision with a $6.0 million payment received by the Company. At maturity, the value of the Second FCX Contingent Payment Provision was zero based on the actual results of the average price of WTI crude oil over the period determined in the agreement; therefore, no payment was due to the Company.

The following table provides the revaluation effect of the Company’s derivative on the Consolidated Statements of Operations (in millions):

		Amount of gain (loss) recognized in income (loss)	
Derivative	Classification of gain (loss) recognized in income (loss)	Year ended December 31, 2017	Year ended December 31, 2016
FCX Contingent Payments Provisions	Other - net	$(0.1)	$ (0.1)

NOTE 8 – 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 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.

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

Derivative

The fair values of the FCX Contingent Payments Provisions (Level 3) were estimated using a Monte Carlo simulation model, which calculated the probabilities of the daily closing WTI spot price exceeding the Price Targets on a daily averaging basis during the 12-month payment measurement period ending on June 30, 2017. The probabilities were applied to the payout at each price target to calculate the probability-weighted expected payout. The following were the significant inputs used in the valuation of the FCX Contingent Payments Provisions: the WTI Spot Price on the valuation date, the expected volatility, and the risk-free interest rate, and the slope of the WTI forward curve, which were $47.48, 37.5%, 0.765% and 5.5% at May 23, 2016, respectively, and $53.72, 28.557%, 0.734%, and 11.205% at December 31, 2016, respectively. The expected volatility was estimated from the implied volatility rates of WTI crude futures. The risk-free rate was based on yields of U.S. Treasury securities commensurate with the remaining term of the FXC Contingent Payments. At December 31, 2016, the Company valued the FCX Contingent Payments Provisions in the amount of $6.1 million which was classified as Prepaid expenses and other current assets on the Consolidated Balance Sheet. In January 2017, the Company and FCX settled the First FCX Contingent Payment Provision with a $6.0 million payment received by the Company (see Note 1). The Second FCX Contingent Payment Provision had no value at maturity, as the average price of WTI crude oil did not meet the terms specified in the FCX Agreement; therefore, no payment was due to the Company (see Note 7).

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Assets measured at fair value on a recurring basis are presented below (in millions):

		Estimated fair value measurements		
	Fair value	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)	Significant other unobservable inputs (Level 3)
December 31, 2018:				
Assets - cash equivalents	$990.5	$990.5	$ —	$ —
Other assets (Egyptian Pounds)	0.7	0.7	—	—
Other assets (Angolan Kwanza)	1.7	1.7	—	—
December 31, 2017:				
Assets - cash equivalents	$1,332.1	$1,332.1	$ —	$ —
Other assets (Egyptian Pounds)	2.2	2.2	—	—
Other assets (Angolan Kwanza)	4.3	4.3	—	—

At December 31, 2018 and 2017, the Company held Egyptian pounds in the amount of $0.7 million and $2.2 million, respectively, which are classified as Other assets on the Consolidated Balance Sheets. The Company ceased drilling operations in Egypt in 2014, and is currently working to obtain access to the funds for use outside Egypt to the extent they are not utilized.

Given stricter foreign currency exchange controls in Angola, the Company determined in May 2017 that its previous method of converting Angola Kwanza to USD is likely no longer feasible. As a result, at December 31, 2018 and 2017, the Company classified its Angolan Kwanza USD equivalent balance of $1.7 million and 4.3 million, respectively, as non-current assets in Other assets on the Consolidated Balance Sheets. Currently, the Company considers the amounts to be recoverable and will continue to evaluate options to convert the Angolan Kwanza to USD.

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

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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 years ended December 31 are set forth below (in millions):

	Fair value	Estimated fair value measurements Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total gains (losses)
2016:					
Property and equipment, net [1]	$ 9.3	$ —	$ —	$ 9.3	$ (34.3)

(1) This represents a non-recurring fair value measurement made at September 30, 2016 for five jack-up drilling units.

In 2016, the Company recognized non-cash asset impairment charges aggregating $34.3 million on five of its jack-up drilling units having an aggregate net carrying value of $43.6 million prior to the write-down. Two of these jack-up drilling units were sold in the fourth quarter of 2016 for gross proceeds of approximately $5.0 million and the Company recognized a net loss on sale of $1.2 million. Impairment charges are included in Material Charges and Other Operating Items on the Consolidated Statements of Operations (see "Impairment of Long-lived Assets" in Note 2). The financial information for these rigs has been reported as part of the Jack-ups segment.

Other Fair Value Measurements

Financial instruments not required to be measured at fair value consist of the Company’s publicly traded debt securities. The Company's publicly traded debt securities had a carrying value of $2.511 billion at December 31, 2018, and an estimated fair value at that date aggregating $1.881 billion, compared to a carrying and fair value of $2.510 billion and $2.262 billion, respectively, at December 31, 2017. Fair values of the Company's 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, which is a Level 2 fair value measurement.

Concentrations of Credit Risk

The Company invests its excess cash primarily in time deposits and high-quality money market accounts at several large commercial banks with strong credit ratings, and therefore believes that its 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. The Company routinely evaluates and monitors the credit quality of potential and current customers. The Company maintains reserves for credit losses when necessary and actual losses have been within management's expectations.

Revenue and receivables from transactions with external customers that amount to 10% or more of revenue during the years ended December 31 are set forth below:

Percentage of revenue from major customers:

Customer	Segment	Years ended December 31, 2018	2017	2016
Saudi Aramco	Jack-ups	28%	29%	20%
Anadarko	Deepwater	14%	17%	8 %
ARO Drilling [1]	Jack-ups and Unallocated and other	14%	1 %	—%
BP Trinidad and Tobago	Jack-ups	10%	6 %	5 %
Repsol	Deepwater and Jack-ups	2 %	7 %	12%
ConocoPhillips	Jack-ups	2 %	7 %	11%

Freeport-McMoRan	Deepwater and Jack-ups	1 %	—%	12%
Cobalt International [2]	Deepwater	—%	14%	12%

[1] Includes revenue related to services provided to ARO (see Note 4).
[2] The year ended December 31, 2017, includes amortization of $95.9 million of revenue deferred in 2016 related to a contract amendment to the Company's subsidiary's drilling contract with Cobalt International (See Note 1).

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Percentage of receivables from major customers:

Customer	Segment	December 31, 2018	2017
Saudi Aramco	Jack-ups	21%	34%
Anadarko	Deepwater	—%	19%
ARO Drilling [1]	Jack-ups and Unallocated and other	30%	9 %
BP Trinidad and Tobago	Jack-ups	9 %	6 %
Repsol	Deepwater and Jack-ups	4 %	5 %
ConocoPhillips	Jack-ups	—%	8 %
Freeport-McMoRan	Deepwater and Jack-ups	1 %	—%
Cobalt International	Deepwater	—%	—%

[1] Includes receivables related to services provided to ARO (see Note 4).

NOTE 9 – 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 $7.4 million, $11.4 million and $10.6 million in 2018, 2017 and 2016, respectively.

At December 31, 2018, future minimum payments to be made under noncancelable operating leases were as follows (in millions):

2019	$7.6
2020	5.1
2021	1.9
2022	1.8
2023	1.8
Later years	10.0
	$28.2

The Company had commitments for purchase obligations totaling $128.0 million at December 31, 2018.

Letters of credit – The Company periodically employs letters of credit in the normal course of its business and had outstanding letters of credit of approximately $9.1 million at December 31, 2018, of which $6.8 million were issued under the Company's New Credit Facility.

Joint venture funding obligations – Each of Rowan and Saudi Aramco have agreed to take all steps necessary to ensure that ARO purchases at least 20 new build jack-up rigs ratably over 10 years once Saudi Aramco's joint venture to manufacture rigs commences operations. The first rig is expected to be delivered as early as 2021. Rowan and Saudi Aramco intend that the newbuild jack-up rigs will be financed out of available cash from operations and/or funds available from third party debt financing. The parties agreed that Saudi Aramco as a customer will provide drilling contracts to ARO in connection with the acquisition of the new rigs, which contracts could be used as security for third party debt financing if needed. If cash from operations or financing is not available to fund the cost of the newbuild jack-up rig, each partner is obligated to contribute funds, in the form of additional shareholder loans, to purchase such rigs, over time of up to a maximum amount of $1.25 billion per partner in the aggregate for all 20 newbuild jack-up rigs, which total investment amount is subject to a reduction formula as rigs are delivered. Further, no shareholder will be required to fund the delivery of more than three rigs during any twelve (12) month period.

Uncertain tax positions – The Company has been advised by the IRS of proposed unfavorable tax adjustments of $85 million including applicable penalties for the open tax years 2009 through 2012. The unfavorable tax adjustments primarily related to the following items: 2009 tax benefits recognized as a result of applying the facts of a third-party tax case that provided favorable tax treatment for certain non-U.S. contracts entered into in prior years to the Company’s situation; transfer pricing; and domestic production activity deduction. The Company has protested the proposed adjustment. However, the IRS does not agree with the Company's protest and they have submitted the proposed unfavorable tax adjustments to be reviewed by the IRS appeals group. In years subsequent to 2012, the

Company has similar positions that could be subject to adjustments for the open years. The

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Company has provided for amounts that it believes will be ultimately payable under the proposed adjustments and intends to vigorously defend its positions; however, if the Company determines the provisions for these matters to be inadequate due to new information or the Company is required to pay a significant amount of additional U.S. taxes and applicable penalties and interest in excess of amounts that have been provided for these matters, the Company's consolidated results of operations and cash flows could be materially and adversely affected.

The gross unrecognized tax benefits excluding penalties and interest are $98 million and $102 million as of December 31, 2018 and 2017, respectively. The decrease to gross unrecognized tax benefits was primarily due to the lapse in statutes of limitation, partially offset by tax positions taken related to current year anticipated transfer pricing positions and potential audit settlement. If the December 31, 2018 net unrecognized tax benefits excluding penalties and interest were recognized, this would favorably impact the Company's tax provision by $35 million.

It is reasonable that the existing liabilities for the unrecognized tax benefits may increase or decrease over the next 12 months as a result of audit closures and statute expirations, however, the ultimate timing of the resolution and/or closure of audits is highly uncertain.

Pending or threatened litigation – The Company is involved in various routine legal proceedings incidental to its businesses and vigorously defends its position in all such matters. Although the outcome of such proceedings cannot be predicted with certainty, the Company believes that there are no known contingencies, claims or lawsuits that will have a material adverse effect on its financial position, results of operations or cash flows.

In addition to the legal proceedings described above, the Company received a claim in February 2018 by a former agent in the Middle East for compensation associated with the Company's termination of the agent's services. As of December 31, 2018, this matter has been resolved.

NOTE 10 – SHARE-BASED COMPENSATION PLANS

Under the Plan, the Company Compensation Committee is authorized to grant employees and non-employee directors incentive awards in the form of RSAs, RSUs, options and SARs. In addition, the Company Compensation Committee may grant performance-based awards under the Plan (such as P-Units which may be settled in shares, cash, or a combination thereof at the discretion of the Company Compensation Committee), for which the amount earned is dependent on the achievement of certain market or performance conditions over a specified period. As of December 31, 2018, there were 7,075,015 shares available for future grant under the Plan. Shares issued to satisfy awards to employees are issued from the Company's EBT which are deemed treasury shares, while shares issued to satisfy awards to non-employee directors are newly issued shares. Compensation cost charged to expense under all share-based incentive awards is presented below (in millions):

	2018	2017	2016
Restricted shares and restricted share units	$18.0	$19.3	$21.8
Share appreciation rights	—	—	0.2
Performance-based awards	6.0	9.7	12.6
Total compensation cost	$24.0	$29.0	$34.6

As of December 31, 2018, unrecognized compensation cost related to nonvested share-based compensation arrangements totaled $28.2 million, which is expected to be recognized over a weighted-average period of 1.6 years.

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Restricted Shares (Employees and Non-employee Directors) – RSAs represent ordinary shares subject to a vesting period that restricts its sale or transfer until the vesting period ends. Activity related to RSAs for the year ended December 31, 2018, is summarized below:

	Number of Shares (in thousands)	Weighted-average grant-date fair value per share
Nonvested at January 1, 2018	—	$ —
Granted [1]	367	14.99
Vested [1]	(141)	15.18
Nonvested at December 31, 2018	226	$ 14.88

[1] On December 18, 2018, the Compensation Committee converted RSUs of certain officers to RSAs to mitigate potential adverse tax consequences to the Company and such employees. The vesting of a portion of these RSA grants was accelerated and shares withheld to satisfy withholding tax obligations. Such vested portion of the RSAs had a fair market value on the vesting date equal to the employment and income tax liability imposed on each officer in connection with such officer's commitment to make an election under Section 83(b) of the Code with respect to the receipt of the RSAs. Such RSAs remain subject to the same terms and conditions of the underlying RSU Award from which they were converted and, with the exception of those RSAs vested and withheld for tax purposes, will be subject to forfeiture, as applicable, by each such officer in the event that the underlying RSU Awards would not have vested. The price of the Company's stock, immediately before the conversion of RSUs to RSAs as compared to the price on the date of such conversion, decreased; thus there was no increase to compensation expense related to the modification.

The weighted-average grant date fair value of RSAs granted in 2018 and 2016 was $14.99 and $18.60, respectively. No RSAs were granted in 2017. The aggregate fair value of RSAs that vested in 2018, 2017 and 2016 was $1.3 million, $758 thousand and $37 thousand, respectively, based on share prices on the vesting dates.

Employee 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, 2018, follows:

	Number of Shares (in thousands)	Weighted-average grant-date fair value per share
Nonvested at January 1, 2018	2,436	$ 15.59
Granted	1,334	13.60
Vested	(1,004)	15.44
Forfeited	(193)	14.32
Cancelled [1]	(367)	14.99
Nonvested at December 31, 2018	2,206	$ 14.67

(1) On December 18, 2018, the Compensation Committee converted RSUs of certain officers to RSAs to mitigate potential adverse tax consequences to the Company and such employees. The vesting of a portion of these RSA grants was accelerated and shares witheld to satisfy withholding tax obligations. Such vested portion of the RSAs had a fair market value on the vesting date equal to the employment and income tax liability imposed on each officer in connection with such officer's commitment to make an election under Section 83(b) of the Code with respect to the receipt of the RSAs. Such RSAs remain subject to the same terms and conditions of the underlying RSU Award from which they were converted and, with the exception of those RSAs vested and withheld for tax purposes, will be subject to forfeiture, as applicable, by each such officer in the event that the underlying RSU Awards would not have vested. The price of the Company's stock, immediately before the conversion of RSUs to RSAs as compared to the price on the date of such conversion, decreased; thus there was no increase to compensation expense related to the modification.

The weighted-average grant date fair value of employee RSUs granted in 2018, 2017 and 2016 was $13.60, $17.09 and $11.62, respectively. The aggregate fair value of employee RSUs that vested in 2018, 2017 and 2016 was $13.7 million, $17.8 million and $14.6 million, respectively.

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Non-employee Director Deferred Restricted Share Units and Non-employee Director Non-Deferred Restricted Share Units – Non-employee directors may annually elect to receive either Directors RSUs or Directors ND RSUs. Both Directors RSUs and Directors ND RSUs vest at the earlier of the first anniversary of the grant date or the next annual meeting of shareholders following the grant date. Directors ND RSUs are settled on the vesting date, while Director RSUs are not settled until the director terminates service from the Board. Both Directors ND RSUs and Directors RSUs are settled in cash, shares or a combination thereof at the discretion of the Company Compensation Committee.

Activity related to Directors RSUs for the year ended December 31, 2018, follows:

	Number of shares (in thousands)	Weighted-average grant-date fair value per share
Outstanding at January 1, 2018	203	$ 25.62
Granted	26	15.29
Settled	—	—
Outstanding at December 31, 2018	229	$ 24.44
Vested at December 31, 2018	203	$ 25.62

The weighted-average grant date fair value of non-employee Directors RSUs granted in 2018, 2017 and 2016 was $15.29, $13.24 and $17.43, respectively. The number and aggregate settlement-date fair value of Directors RSUs settled during the year were as follows: 2018 – none; 2017 – 114 thousand Directors RSUs at $1.5 million; 2016 – 54 thousand Directors RSUs at $1.0 million.

Activity related to Directors ND RSUs for the year ended December 31, 2018, follows:

	Number of shares (in thousands)	Weighted-average grant-date fair value per share
Outstanding at January 1, 2018	91	$ 13.24
Granted	78	15.29
Settled	(91)	13.24
Outstanding at December 31, 2018	78	$ 15.29
Vested at December 31, 2018	—	$ —

The weighted-average grant date fair value of non-employee Directors ND RSUs granted in 2018 and 2017 was $15.29 and $13.24, respectively. The aggregate settlement-date fair value of Directors ND RSUs settled during the year were as follows: 2018 - 91 thousand Directors ND RSUs at $1.4 million.

Directors RSUs and Directors ND RSUs are accounted for under the liability method. Accordingly, other long-term liabilities at December 31, 2018 and 2017, included $2.3 million and $3.8 million, respectively, related to such awards.

Performance-based Awards – During 2016, 2017 and 2018, the Company granted to certain members of management P-Units that have a target value of $100 per unit.

The amount ultimately earned for P-Units granted in 2018 is determined by the Company’s absolute TSR performance and relative TSR performance as measured against a group of companies selected by the Company Compensation Committee, over a three-year period ending December 31, 2020. The amount earned could range from zero to $200 per unit depending on the Company's performance. Twenty-five percent of the P-Units’ value is determined by the Company’s absolute TSR performance and relative TSR ranking for each one-year period ended December 31, 2018, 2019, and 2020 and 25% of the P-Units’ value is determined by the Company's absolute TSR performance and relative TSR ranking for the three-year period ended December 31, 2020.

The amount ultimately earned for the 2017 and 2016 P-Units is determined by the Company's relative TSR relative to a select group of peer companies, as selected by the Company Compensation Committee, over a three-year period ending December 31, 2019 and 2018 for the 2017 and 2016 grants, respectively. The amount earned could range from zero to $200 per unit depending on the Company's performance. Twenty-five percent of the P-Units’ value is determined by the Company’s relative TSR ranking

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for each one-year period ended December 31 and 25% of the P-Units' value is determined by the Company's relative TSR ranking for the three-year period ended December 31.

P-Units cliff vest and payment is made, if any, on 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 Company Compensation Committee. Settlement of the P-Units granted may be in cash, shares or a combination thereof, at the Company Compensation Committee's discretion.

The grant date fair value of P-Units granted in 2018, 2017 and 2016 was estimated to be $7.0 million, $9.5 million and $8.6 million, respectively. Fair value for P-units are estimated using the Monte Carlo simulation model, which considers the probabilities of the Company's relative TSR performance and 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 generally 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 end of the performance period. The Company recognizes compensation cost on the accelerated method for those retirement eligible or who will become retirement eligible during the vesting period as the awards provide for pro-rata vesting rather than full vesting if a retirement eligible employee retires prior to the end of the 36 months service period.

Liabilities for estimated P-Unit obligations at December 31, 2018 for 2018 grants and prior, included $9.1 million and $7.0 million classified as current and noncurrent, respectively, compared to $11.5 million and $10.5 million, respectively, at December 31, 2017. Current and noncurrent estimated P-Unit liabilities are included in Accrued liabilities, and Other liabilities, respectively, in the Consolidated Balance Sheets.

In 2018, 2017 and 2016, the Company paid $11.9 million, $11.4 million and $7.9 million, respectively, in cash to settle P-Units that vested during the year.

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.

No SARs have been granted since 2013.

SARs activity for the year ended December 31, 2018, is summarized below:

	Number of shares under SARs (in thousands)	Weighted-average exercise price	Weighted-average remaining contractual term (in years)	Aggregate intrinsic value (in millions)
Outstanding at January 1, 2018	1,029	$ 31.03		
Forfeited or expired	(17)	36.86		
Outstanding at December 31, 2018	1,012	$ 30.93	2.0	$ —
Exercisable at December 31, 2018	1,012	$ 30.93	2.0	$ —

No SARs were exercised in 2018, 2017 and 2016.

Share Options – Share options granted to employees in 2017 become exercisable and cliff vest at the end of a four-year vesting period at a price generally equal to the market price of the Company's common shares on the date of grant. The remaining share options became exercisable over a three- year service period at a price generally equal to the market price of the Company's common shares on the date of grant. Unexercised options expire seven years after the grant date.

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

	February 22, 2017
Expected life in years	5.5
Risk-free interest rate	1.987 %
Expected volatility	40.551%
Weighted average grant date per share fair value	$ 7.04

Share option activity for the year ended December 31, 2018, is summarized below:

	Number of shares under option (in thousands)	Weighted-average exercise price	Weighted-average remaining contractual term (in years)	Aggregate intrinsic value (in thousands)
Outstanding at January 1, 2018	455	$ 17.08		
Exercised	(5)	15.31		$ 19.2
Expired	(95)	15.31		
Outstanding at December 31, 2018	355	$ 17.59	5.1	—
Exercisable at December 31, 2018	—	$ —	0.0	$ —

5 thousand options were exercised in 2018. No options were exercised in 2017 or 2016.

NOTE 11 – 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 Rowan SERP, and health care and life insurance benefits are provided under the Retiree Medical Plan.

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 millions):

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	2018 Pension benefits	Other benefits	Total	2017 Pension benefits	Other benefits	Total
Projected benefit obligations:						
Balance, January 1	$835.8	$18.0	$853.8	$772.1	$29.9	$802.0
Interest cost	27.9	0.5	28.4	25.5	0.9	26.4
Service cost	6.1	0.1	6.2	12.3	0.1	12.4
Actuarial (gain) loss	(51.4)	(1.2)	(52.6)	78.0	5.5	83.5
Plan amendments	(0.5)	—	(0.5)	—	—	—
Plan settlements	—	—	—	—	(16.4)	(16.4)
Plan curtailments	(1.1)	—	(1.1)	—	—	—
Exchange rate changes	(0.4)	—	(0.4)	0.3	—	0.3
Benefits paid	(57.7)	(1.4)	(59.1)	(52.4)	(2.0)	(54.4)
Balance, December 31	758.7	16.0	774.7	835.8	18.0	853.8
Plan assets:						
Fair value, January 1	609.7	—	609.7	544.6	—	544.6
Actual return	(40.5)	—	(40.5)	88.0	—	88.0
Employer contributions	24.2	—	24.2	29.3	—	29.3
Plan settlements	—	—	—	—	—	—
Exchange rate changes	(0.2)	—	(0.2)	0.2	—	0.2
Benefits paid	(57.7)	—	(57.7)	(52.4)	—	(52.4)
Fair value, December 31	535.5	—	535.5	609.7	—	609.7
Net benefit liabilities	$(223.2)	$(16.0)	$(239.2)	$(226.1)	$(18.0)	$(244.1)
Amounts recognized in Consolidated Balance Sheet:						
Accrued liabilities	$(15.1)	$(1.7)	$(16.8)	$(24.5)	$(2.5)	$(27.0)
Other liabilities (long-term)	(208.1)	(14.3)	(222.4)	(201.6)	(15.5)	(217.1)
Net benefit liabilities	$(223.2)	$(16.0)	$(239.2)	$(226.1)	$(18.0)	$(244.1)
Accumulated contributions in excess of (less than) net periodic benefit cost	$141.7	$(25.8)	$115.9	$120.2	$(39.1)	$81.1
Amounts not yet reflected in net periodic benefit cost:						
Actuarial (loss) gain	(364.2)	(4.3)	(368.5)	(358.1)	(6.3)	(364.4)
Prior service credit	(0.7)	14.1	13.4	11.8	27.4	39.2
Total accumulated other comprehensive income (loss)	(364.9)	9.8	(355.1)	(346.3)	21.1	(325.2)
Net benefit liabilities	$(223.2)	$(16.0)	$(239.2)	$(226.1)	$(18.0)	$(244.1)
Weighted-average assumptions:						
Discount rate	4.35 %	4.23 %		3.68 %	3.52 %	
Rate of compensation increase	3.78 %			4.28 %		

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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 millions):

	2018	2017
Accumulated benefit obligation	$754.7	$830.8

Over the past 10 years, there have been various changes to our pension plan which have significantly reduced participant benefits under such plan. Further, on May 11, 2018, the Company communicated changes to the participants in its pension plan, that will "freeze" this plan going forward. Based on these changes, effective as of June 30, 2018, eligible participants will no longer receive pay credits and newly hired employees will not be eligible to participate in the pension plan. For the purposes of remeasurement, the Company used the date of April 30, 2018 as it was the month-end date that is closest to May 11, 2018. The impacts of these changes to the plan as of May 11, 2018, are presented in the table below (in millions):

	Liability increase (decrease)	Accumulated other comprehensive income (loss)	Deferred tax asset decrease (increase)	Income included in Other-net	Income tax expense (increase) decrease
Plan change to projected benefit obligation	$ (1.6)	$ 1.3	$ 0.3	$ —	$ —
Remeasurement gain	(29.9)	23.6	6.3	—	—
Curtailment	—	(9.0)	(1.0)	11.4	(1.4)
Total	$ (31.5)	$ 15.9	$ 5.6	$ 11.4	$ (1.4)

The Company records unrealized gains and losses related to net periodic pension and other postretirement benefit cost net of estimated taxes in Accumulated other comprehensive income (loss).

On November 27, 2017, the Company purchased annuities to cover post-65 retiree medical benefits for current retirees as of the purchase date. The annuity purchase settled post-65 medical benefits (i.e., Health Reimbursement Account, or “HRA”, amounts) for affected participants, with the insurer taking responsibility for all benefit payments on and after January 1, 2019. The Company retained the obligation for 2018 benefit payments. The Company determined that this annuity purchase resulted in a full settlement of the post-65 medical obligation and as a result the entirety of the annuity purchase was treated as a settlement and resulted in a settlement loss of $5.8 million, calculated as of December 31, 2017.

On August 10, 2016, the Company communicated changes to the participants in its postretirement benefits plan, which was previously frozen to new entrants in 2008. Based on these changes, effective as of January 1, 2017, eligible participants now receive a health reimbursement account that provides a fixed dollar benefit per year. The impact of these changes to the plan and related, as of August 10, 2016, are presented in the table below (in millions):

	Liability increase (decrease)	Accumulated other comprehensive income (loss)	Deferred tax liability increase (decrease)
Plan change benefit	$ (39.9)	$ 25.9	$ 14.0
Remeasurement loss	5.2	(3.4)	(1.8)
Actuarial loss	5.2	(3.3)	(1.9)
Total	$ (29.5)	$ 19.2	$ 10.3

During 2016, the Rowan SERP had a one-time settlement charge recognized in net periodic pension costs under US GAAP of $0.5 million as of December 31, 2016, attributable to lump sum payments during 2016 which exceeded the sum of the service cost and interest cost, the threshold that requires recognition of a settlement loss.

In 2016, the Norwegian Onshore and Offshore pension plans both experienced plan curtailments. Across Rowan Norway Limited, which employs participants of both the Onshore and Offshore pension plans, there was an employment reduction resulting in an approximate 50% reduction in active participants of the plans in early 2017. Since Rowan provided affected employees redundancy letters in November 2016, the curtailment was recognized effective December 31, 2016. The Company recognized a $0.4 million curtailment gain in net periodic pension costs for 2016.

During 2015, the Company 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

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benefit obligation by $7.2 million, which was net of an estimated $4.4 million payment to be made in early 2016 to the affected participants. The actual payment made in 2016 was $2.6 million and the Company recognized a related $0.1 million settlement loss.

Effective January 1, 2016, the Company changed its estimate of the service and interest cost components of net periodic benefit costs for its significant defined benefit pension and other postretirement benefit plans. Previously, the Company estimated the service and interest cost components utilizing a single weighted-average discount rate derived from the yield curve used to measure the benefit obligation. The new estimate utilizes a full yield curve approach in the estimation of these components by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to their underlying projected cash flows. The new estimate provides a more precise measurement of service and interest costs by improving the correlation between projected benefit cash flows and their corresponding spot rates. While the benefit obligation measured under this approach is unchanged, more granular application of the spot rates reduced the service and interest cost for fiscal 2016.

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 2019 (in millions):

	Pension benefits	Other retirement benefits	Total
Actuarial (loss) gain	$ (9.0)	$ (0.6)	$ (9.6)
Prior service credit	—	12.4	12.4
Total amortization	$ (9.0)	$ 11.8	$ 2.8

Cumulative gains and losses in excess of 10% of the greater of projected benefit obligation or market-related value of plan assets are amortized over the expected average remaining service of the current active membership. If all members of a plan are inactive, the amortization is based on their average remaining life expectancy instead of expected average remaining service.

Each unrecognized prior service cost base is amortized on a straight line basis over the average remaining service period of participants expected to receive a benefit and who are active at the date of the plan amendment. If all or almost all of the plan's participants offered a benefit by the plan amendment are inactive, the amortization is based on their average remaining life expectancy instead of average remaining service.

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

	2018	2017	2016
Service cost (1)	$ 6.1	$ 12.3	$ 16.3
Interest cost (2)	27.9	25.5	26.3
Expected return on plan assets (2)	(36.5)	(37.7)	(39.6)
Recognized actuarial loss (2)	18.5	23.3	21.0
Amortization of prior service credit (2)	(1.7)	(5.1)	(5.0)
Curtailment gain recognized (2)	(11.4)	—	(0.4)
Settlement loss recognized (2)	—	—	0.5
Net periodic pension cost	$ 2.9	$ 18.3	$ 19.1
Discount rate	3.69 %	4.29 %	4.53 %
Expected return on plan assets	6.68 %	7.13 %	7.28 %
Rate of compensation increase	4.28 %	4.14 %	4.14 %

(1) Included in Direct operating costs and Selling, general and administrative on the Consolidated Statements of Operations

(2) Included in Other - net on the Consolidated Statements of Operations

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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 millions):

	2018	2017	2016
Service cost [1]	$0.1	$0.1	$0.3
Interest cost [2]	0.5	0.9	1.6
Amortization of prior service credit [2]	(13.3)	(13.3)	(6.4)
Amortization of net (gain) loss [2]	0.8	0.7	0.3
Settlement loss [2]	—	5.8	0.1
Net periodic cost of other postretirement benefits	$(11.9)	$(5.8)	$(4.1)
Discount rate	3.50 %	3.91 %	4.18 %

(1) Included in Direct operating costs and Selling, general and administrative on the Consolidated Statements of Operations
(2) Included in Other - net on the Consolidated Statements of Operations

The pension plans' investment objectives for fund assets are: to achieve over the life of the plans a return equal to the plans' expected investment return or the inflation rate plus 3%, whichever is greater; to invest assets in a manner such that contributions are minimized and future assets are available to fund liabilities; to maintain liquidity sufficient to pay benefits when due; and to diversify among asset classes so that assets earn a reasonable return with an acceptable level of risk. The plans employ several active managers with proven long-term records in their specific investment discipline.

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Target allocations among asset categories and the fair values of each category of plan assets as of December 31, 2018 and 2017, classified by level within the US GAAP fair value hierarchy are presented below. The plans will periodically reallocate assets in accordance with the allocation targets, after giving consideration to the expected level of cash required to pay current benefits and plan expenses (dollars in millions):

	Target range	Total	Quoted prices in active markets for identical assets (Level 1)	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
December 31, 2018:					
Equities:	53% to 69%				
U.S. large cap	22% to 28%	$131.6	$ —	$ 131.6	$ —
U.S. small cap	4% to 10%	35.6	—	35.6	—
International all cap	21% to 29%	129.9	—	129.9	—
International small cap	2% to 8%	28.8	—	28.8	—
Real estate equities	0% to 13%	51.7	—	51.7	—
Fixed income:	25% to 35%				
Cash and equivalents	0% to 10%	4.1	—	4.1	—
Aggregate	9% to 19%	73.9	—	73.9	—
Core plus	9% to 19%	74.7	74.7	—	—
Group annuity contracts		5.2	—	5.2	—
Total		$535.5	$ 74.7	$ 460.8	$ —
December 31, 2017:					
Equities:	53% to 69%				
U.S. large cap	22% to 28%	$158.2	$ —	$ 158.2	$ —
U.S. small cap	4% to 10%	45.3	—	45.3	—
International all cap	21% to 29%	156.2	—	156.2	—
International small cap	2% to 8%	36.3	—	36.3	—
Real estate equities	0% to 13%	50.6	—	50.6	—
Fixed income:	25% to 35%				
Cash and equivalents	0% to 10%	6.2	—	6.2	—
Aggregate	9% to 19%	74.9	—	74.9	—
Core plus	9% to 19%	78.1	78.1	—	—
Group annuity contracts		3.9	—	3.9	—
Total		$609.7	$ 78.1	$ 531.6	$ —

Assets in the U.S. equities category include investments in common and preferred stocks (and equivalents such as American Depository Receipts and convertible bonds) and may be held through separate accounts, commingled funds or an institutional mutual fund. Assets in the international equities category include investments in a broad range of international equity securities, including both developed and emerging markets, and may be held through a commingled or institutional mutual fund. The real estate category includes investments in pooled and commingled funds whose objectives are diversified equity investments in income-producing properties. Each real estate fund is intended to provide broad exposure to the real estate market by property type, geographic location and size and may invest internationally. Securities in both the aggregate and core plus fixed income categories include U.S. government, corporate, mortgage- and asset-backed securities and Yankee bonds, and both categories target an average credit rating of "A" or better at all times. Individual securities in the aggregate fixed income category must be investment grade or above at the time of purchase, whereas securities in the core plus category may have a rating of “B” or above. Additionally, the core plus category may invest in non-U.S. securities. Assets in the aggregate and core plus fixed income categories are held primarily through a commingled fund and an institutional mutual fund, respectively. Group annuity contracts are invested in a combination of equity, real estate, bond and other investments in connection with a pension plan in Norway.

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The following is a description of the valuation methodologies used for the pension plan assets at December 31, 2018, and 2017:

- Fair values of all U.S. equity securities, the international all cap equity securities and aggregate fixed income securities categorized as Level 2 were held in commingled funds which were valued daily based on a net asset value.
- Fair value of international small cap equity securities categorized as Level 2 were held in a limited partnership fund which was valued monthly based on a net asset value.
- The real estate categorized as Level 2 was held in two accounts (a commingled fund and a limited partnership). The assets in the commingled fund were valued monthly based on a net asset value and the assets in the limited partnership were valued quarterly based on a net asset value.
- Cash and equivalents categorized as Level 2 were valued at cost, which approximates fair value.
- Fair value of mutual fund investments in core plus fixed income securities categorized as Level 1 were based on quoted market prices which represent the net asset value of shares held.

To develop the expected long-term rate of return on assets assumption, the Company 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 plans, which was 6.70% at both December 31, 2018 and 2017. The Company's estimates for its net benefit expense (income) are partially based on the expected return on pension plan assets. The Company uses a market-related value of plan assets to determine the expected return on pension plan assets. In determining the market-related value of plan assets, differences between expected and actual asset returns are deferred and recognized over two years. If the Company used the fair value of its plan assets instead of the market-related value of plan assets in determining the expected return on pension plan assets, its net benefit expense would have been $3.0 million lower for the year ended December 31, 2018.

The Company bases its determination of the asset return component of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a two-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a two-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of January 1, 2019, cumulative asset losses of approximately $36.6 million remained to be recognized in the calculation of the market-related value of assets.

The Company currently expects to contribute approximately $15 million to its pension plans in 2019 and to directly pay other postretirement benefits of approximately $2 million.

Estimated future annual benefit payments from plan assets are presented below. Such amounts are based on existing benefit formulas and include the effect of future service (in millions):

	Pension benefits	Other postretirement benefits
Year ended December 31,		
2019	$ 48.5	$ 1.7
2020	49.7	1.6
2021	50.5	1.4
2022	51.0	1.4
2023	51.3	1.3
2024 through 2028	256.4	5.9

The Company sponsors defined contribution plans covering substantially all employees. Employer contributions to such plans are expensed as incurred and totaled $12.1 million in 2018, $12.5 million in 2017 and $16.7 million in

2016.

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NOTE 12 – SHAREHOLDERS' EQUITY

Reclassifications from Accumulated Other Comprehensive Loss

The following table sets forth the significant amounts reclassified out of each component of accumulated other comprehensive loss and their effect on net income (loss) for the period (in millions):

	2018	2017	2016
Amounts recognized as a component of net periodic pension and other postretirement benefit cost:			
Amortization of net loss	$(19.3)	$(29.8)	$(21.9)
Amortization and curtailment recognition of prior service credit	26.4	18.4	10.7
Total before income taxes	7.1	(11.4)	(11.2)
Income tax (expense) benefit	(1.5)	—	3.8
Total reclassifications for the period, net of income taxes	$5.6	$(11.4)	$(7.4)

The Company records unrealized gains and losses related to net periodic pension and other postretirement benefit cost net of estimated taxes in Accumulated other comprehensive income (loss).

Cash Dividends

Under English law, a public company may only declare dividends and make other distributions to shareholders (such as a share buyback) if the company has sufficient distributable reserves and meets certain net asset requirements. If the Company does not have sufficient distributable reserves or cannot meet the net asset requirements, the Company may be limited in its ability to timely pay dividends and effect other distributions to its shareholders.

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

NOTE 13 – INCOME TAXES

Rowan plc, the parent company, is domiciled in the U.K. and is subject to the U.K. statutory rate of 20% for the period January 1, 2016 through March 31, 2017 and 19% beginning April 1, 2017. On September 15, 2016, the U.K. enacted tax law to reduce the tax rate to 17% beginning April 1, 2020. The U.K. statutory tax rate for 2018 is 19.00%.

On December 22, 2017, the U.S. government enacted tax legislation commonly referred to as the U.S. Tax Act. The U.S. Tax Act significantly changes U.S. corporate income tax laws including but not limited to reducing the U.S. corporate income tax rate from 35% to 21% as of January 1, 2018, implementing a tax determined by base erosion and anti-abuse tax, (also known as "BEAT"), from certain payments between a U.S. corporation and its foreign subsidiaries as of January 1, 2018, requiring a one-time transition tax on mandatory deemed repatriation of certain unremitted non-U.S. earnings as of December 31, 2017, and changing how non-U.S. subsidiaries are taxed in the U.S. as of January 1, 2017.

Additionally, SEC Staff Accounting Bulletin No. 118 was issued to address the complex computations related to the U.S. Tax Act by allowing provisional estimates. During 2018, the Company finalized its analysis and calculations resulting in adjustments to its December 31, 2017 estimate related to transition tax from $34.1 million to $26.4 million and tax on non-U.S. subsidiaries from $38.3 million to $33.7 million resulting in a reduction to tax expense of $12.3 million. The Company has offset these charges with net operating losses. The December 31, 2017 estimate for remeasurement of U.S. deferred tax assets and liabilities for the income tax rate reduction was adjusted from $56.7 million to $61.6 million resulting in an increase to tax expense of $4.9 million.

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The significant components of income taxes attributable to continuing operations are presented below (in millions):

	2018	2017	2016
Current:			
U.S.	$2.9	$(14.9)	$10.0
Non - U.S.	13.6	16.8	32.9
State	—	—	—
Current expense (benefit)	16.5	1.9	42.9
Deferred:			
U.S.	(69.8)	(1.2)	(20.9)
Non - U.S.	1.7	25.9	(17.0)
Deferred provision (benefit)	(68.1)	24.7	(37.9)
Total provision (benefit)	$(51.6)	$26.6	$5.0

The reconciliation of differences between the Company's provision for income taxes and the amount determined by applying the U.K. statutory rate to income before income taxes are set forth below (dollars in millions):

	2018	2017	2016
U.K. statutory rate	19.00 %	19.25 %	20.00 %
Tax at statutory rate	$(75.8)	$19.1	$65.1
Increase (decrease) due to:			
Foreign rate differential	9.6	(39.5)	(92.7)
Deferred intercompany gain/loss	—	—	(20.1)
Foreign asset basis difference	1.8	(38.1)	405.9
Luxembourg restructuring operating loss [2]	(22.9)	—	(1,180)2
Change in valuation allowance	37.6	(29.4)	814.7
Prior period adjustments	(2.9)	3.6	(4.1)
Unrecognized tax benefits	(4.7)	(24.1)	7.1
U.S. tax on RCI non-U.S. subsidiaries	9.4	5.4	6.3
Enactment of tax reform [1]	(7.4)	129.1	—
Foreign tax credits/deductions	—	(0.8)	(1.5)
Other, net	3.7	1.3	4.5
Total provision (benefit)	$(51.6)	$26.6	$5.0

[1] 2017 includes the U.S. tax rate reduction, one-time transition tax, and U.S. tax on applicable non-U.S. subsidiaries earnings. The impact of the 2017 items are fully offset in the change in valuation allowance above. 2018 includes the finalization of these impacts.

[2] In 2016, organizational restructuring resulted in a Luxembourg net operating loss of $4,534 million resulting in a deferred tax asset of $1,180 million with an offsetting deferred tax liability for book over tax asset basis difference of $409 million and a valuation allowance of $747 million for the net deferred tax asset that is not expected to be realized.

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Temporary differences and carryforwards which gave rise to deferred tax assets and liabilities at December 31 were as follows (in millions):

	2018	2017
Deferred tax assets:		
Accrued employee benefit plan costs	$48.2	$46.2
U.S. net operating loss	40.6	39.3
U.K. net operating loss	6.0	2.4
Trinidad net operating loss	5.2	5.9
Luxembourg net operating loss	1,249.4	1,163.2
Suriname net operating loss	3.9	3.9
Other NOLs and tax credit carryforwards	38.0	38.1
Other	18.6	16.3
Total deferred tax assets	1,409.9	1,315.3
Less: valuation allowance	(905.9)	(869.9)
Deferred tax assets, net of valuation allowance	504.0	445.4
Deferred tax liabilities:		
Property and equipment	396.2	412.8
Other	12.3	11.9
Total deferred tax liabilities	408.5	424.7
Net deferred tax asset (liability)	$95.5	$20.7

Management continues to assess available positive and negative evidence to evaluate the existing deferred tax assets' ability to be realized including determining if there is sufficient future taxable income. The Company records the portion of the deferred tax assets that is more likely to be realized. There have been no changes on the prior assessment regarding the ability to realize the Luxembourg deferred tax assets and the Company has assessed the need for a valuation allowance as of December 31, 2018. The Company increased the valuation allowance on the Luxembourg deferred tax assets by $101.4 million to $867.9 million, at December 31, 2018, primarily due to an adjustment related to a filed amended tax return and current year net operating losses. In assessing the future ability to realize the existing U.S. deferred tax assets, the evaluation indicates positive evidence that a portion of the deferred tax assets will be realized. In 2018, the U.S. valuation allowance on U.S. deferred tax assets was decreased by $68.4 million to $22.0 million, related to deferred tax assets that are now expected to be realized.

As of December 31, 2017, the Company increased the valuation allowance on the Luxembourg deferred tax assets by $19.8 million to $766.5 million, primarily due to lower 2017 earnings than expected. In 2017, the U.S. valuation allowance on U.S. deferred tax assets was decreased by $41.7 million to $90.4 million primarily due to a decrease of provisional estimate of $56.7 million for the remeasurement to the lower U.S. corporate income tax rate, a decrease of provisional estimate of $52.1 million for 2017 activity, and an increase of $60.3 million for a deferred intra-entity asset transfer.

The amount of the deferred tax assets considered realizable, however, could be adjusted if estimates of future taxable income during the carryforward period are reduced or increased or if negative evidence in the form of cumulative losses is no longer present, and additional weight may be given to evidence such as projections for growth. As of each reporting date, the Company's management considers new evidence, both positive and negative, that could impact management's view regarding future realization of deferred tax assets.

At December 31, 2018, the Company had approximately $366 million of NOLs in the U.S. expiring at various times between 2035 through 2037, of which $76 million are subject to a valuation allowance; $4,803 million of non-expiring NOLs in Luxembourg of which $3,337 million is subject to a valuation allowance; $36 million of non-expiring NOLs in the U.K., of which $36 million is subject to a valuation allowance; and $21 million of non-expiring NOLs in Trinidad, of which $21 million is subject to a valuation allowance. In addition, at December 31, 2018, the Company had $15 million of non-expiring NOLs in other foreign jurisdictions, of which $15 million is subject to a valuation allowance. A U.S. foreign tax credit of $29 million is intended to be carried back and does not have a valuation allowance. Due to the uncertainty of realization, the Company has a tax-effected valuation allowance as of December 31, 2018, in the amount of $906 million against the deferred tax assets for foreign tax credits, NOL carryforwards, and other deferred tax assets that may not be realizable, primarily relating to countries where the Company no longer operates or does not expect to generate sufficient future taxable income. Management has determined that no other valuation allowances were necessary at December 31, 2018, as anticipated future tax benefits relating to all recognized deferred income tax assets are expected to be fully realized when measured against a more-likely-than-not standard.

The NOL carryforwards included unrecognized tax benefits taken in prior years. The NOLs for which a deferred tax asset is recognized for financial statement purposes in accordance with ASC 740 are presented net of these unrecognized tax benefits.

The Company has not provided deferred income taxes on certain undistributed earnings of non-U.K. subsidiaries. If facts and circumstances cause a change in expectations regarding future tax consequences, the resulting tax impact could have a material effect on the Company's consolidated financial statements.

At December 31, 2018, 2017 and 2016, the net unrecognized tax benefits attributable to continuing operations was approximately $35 million, $41 million and $59 million, respectively. At December 31, 2018, $35 million would reduce the Company’s income tax provision if recognized.

The following table sets forth the changes in the Company’s gross unrecognized tax benefits for the years ended December 31 (in millions):

	2018	2017	2016
Gross unrecognized tax benefits - beginning of year	$102.0	$120.1	$65.1
Gross increases - tax positions in prior period	1.1	1.4	46.2
Gross decreases - tax positions in prior period	(0.3)	(5.6)	(0.6)
Gross increases - current period tax positions	3.2	3.1	10.9
Settlements	—	(0.8)	(1.5)
Lapse of statutes of limitation	(7.8)	(16.2)	—
Gross unrecognized tax benefit - end of year	$98.2	$102.0	$120.1

The interest and penalty benefits and expenses relating to income taxes are included in income tax expense. At December 31, 2018, 2017 and 2016, net accrued interest was $1.7 million, $1.4 million and $11.8 million, respectively, and net accrued penalties were $(0.5) million, $2.2 million and $3.1 million, respectively. Accrued interest and penalties relating to uncertain tax positions that are not actually assessed will be reversed in the year of the resolution.

The Company has been advised by the IRS of proposed unfavorable tax adjustments of $85 million including applicable penalties for the open tax years 2009 through 2012. The unfavorable tax adjustments primarily related to the following items: 2009 tax benefits recognized as a result of applying the facts of a third-party tax case that provided favorable tax treatment for certain non-U.S. contracts entered into in prior years to the Company’s situation; transfer pricing; and domestic production activity deduction. The Company has protested the proposed adjustment. However, the IRS does not agree with the Company's protest and they have submitted the proposed unfavorable tax adjustments to be reviewed by the IRS appeals group. In years subsequent to 2012, the Company has similar positions that could be subject to adjustments for the open years. The Company has provided for amounts that it believes will be ultimately payable under the proposed adjustments and intends to vigorously defend its positions; however, if the Company determines the provisions for these matters to be inadequate due to new information or the Company is required to pay a significant amount of additional U.S. taxes and applicable penalties and interest in excess of amounts that have been provided for these matters, the Company's consolidated results of operations and cash flows could be materially and adversely affected.

The Company’s U.S. federal tax returns for 2009 through 2012 are currently under audit by the IRS. The U.S. tax years open for examination are for periods 2015 and subsequent years. Various state tax returns for 2009 and subsequent years remain open for examination. In the Company’s non-U.S. tax jurisdictions, returns for 2006 and subsequent years remain open for examination. The Company is undergoing other routine tax examinations in various U.S. and non-U.S. taxing jurisdictions in which the Company has operated. These examinations cover various tax years and are in various stages of finalization. The Company believes that any income taxes ultimately assessed by any taxing authorities will not materially exceed amounts for which the Company has already provided, however, if it is determined that the provisions for these matters are inadequate due to new information or that taxing authorities assess a significant amount of additional taxes and applicable penalties and interest in excess of amounts that have been provided for these matters, consolidated results of operations and cash flows could be materially and adversely affected.

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The components of income (loss) from continuing operations before income taxes were as follows (in millions):

	2018	2017	2016
U.S.	$(10.3)	$(63.7)	$(180.2)
Non-U.S.	(388.7)	163.0	505.8
Total	$(399.0)	$99.3	$325.6

NOTE 14 – SEGMENT, DISAGGREGATION OF REVENUE AND GEOGRAPHIC AREA INFORMATION

Prior to ARO commencing operations on October 17, 2017 (see Note 1 and Note 4), the Company operated in two segments: Deepwater and Jack-ups. The Company now operates in three principal operating segments: Deepwater, which consists of its drillship operations, Jack-ups, which is composed of the Company's jack-up operations and results associated with the Company's arrangements with ARO primarily under the Transition Services Agreement (direct operating costs only), Rig Management Agreement, Rig Lease Agreements and Secondment Agreement (see Note 1 and Note 4), and ARO, the Company's 50/50 joint venture with Saudi Aramco. ARO was formed to own, manage and operate offshore drilling units in Saudi Arabia. These segments provide one primary service – contract drilling. The Company evaluates performance primarily based on income from operations.

"Gain on sale of assets to unconsolidated subsidiary" is related to the sale of two jack-ups in 2018 and three jack-ups and related assets in 2017 to ARO and is included in the Jack-ups segment (see Note 1 and Note 15). Depreciation and amortization and Selling, general and administrative expenses related to the Company's corporate function and other administrative offices have not been allocated to its operating segments for purposes of measuring segment operating income and are included in "Unallocated and other." In addition, revenue and general and administrative costs related to providing transition services to ARO are included in "Unallocated and other" (see Note 4). "Other operating items" consists of, to the extent applicable, non-cash impairment charges, losses on disposals of property and equipment and a litigation related item. Segment results are presented below:

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	Years ended December 31,						
	Deepwater	Jack-ups	ARO	Unallocated and other	Reportable segments total	Eliminations and adjustments	Consolidated
	(In millions)						
2018							
Revenue	$158.1	$632.9	$348.8	$ 33.8	$1,173.6	$ (348.8)	$ 824.8
Operating expenses:							
Direct operating costs (excluding items below)	168.6	514.1	194.0	—	876.7	(194.0)	682.7
Depreciation and amortization	108.5	278.3	67.4	2.1	456.3	(67.4)	388.9
Selling, general and administrative	—	—	27.0	96.1	123.1	(27.0)	96.1
Gain on sale of assets to unconsolidated subsidiary	—	(65.8)	—	—	(65.8)	—	(65.8)
Other operating items - expense	1.6	5.3	1.4	5.2	13.5	(1.4)	12.1
Merger and related costs	—	—	—	8.9	8.9	—	8.9
Equity in earnings of unconsolidated subsidiary	—	—	—	—	—	10.3	10.3
Income (loss) from operations	$(120.6)	$(99.0)	$59.0	$ (78.5)	$(239.1)	$ (48.7)	$ (287.8)
2017							
Revenue	$467.9	$807.5	$48.6	$ 7.4	$1,331.4	$ (48.6)	$ 1,282.8
Operating expenses:							
Direct operating costs (excluding items below)	151.4	533.6	22.2	—	707.2	(22.2)	685.0
Depreciation and amortization	111.6	289.4	12.9	2.7	416.6	(12.9)	403.7
Selling, general and administrative	—	—	6.1	104.6	110.7	(6.1)	104.6
Gain on sale of assets to unconsolidated subsidiary	—	(157.4)	—	—	(157.4)	—	(157.4)
Other operating items - (income) expense	0.1	9.3	(0.1)	—	9.3	0.1	9.4
Equity in earnings of unconsolidated subsidiary	—	—	—	—	—	0.9	0.9
Income (loss) from operations	$204.8	$132.6	$7.5	$ (99.9)	$245.0	$ (6.6)	$ 238.4
2016							
Revenue	$827.5	$1,015.7	$—	$ —	$1,843.2	$ —	$ 1,843.2
Operating expenses:							
Direct operating costs (excluding items below)	222.4	557.3	—	—	779.7	—	779.7
Depreciation and amortization	115.0	282.6	—	5.3	402.9	—	402.9
Selling, general and administrative	—	—	—	102.2	102.2	—	102.2
Other operating items - expense	0.1	40.9	—	0.6	41.6	—	41.6
Income (loss) from operations	$490.0	$134.9	$—	$ (108.1)	$516.8	$ —	$ 516.8

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	Years ended December 31,		
	2018	2017	2016
Capital expenditures:	(In millions)		
Deepwater	$16.7	$8.3	$31.5
Jack-ups	145.8	86.4	84.3
Unallocated and other	6.7	5.9	1.8
Total	$169.2	$100.6	$117.6

In January 2018, the Company completed the cash purchase of two rigs, for which a deposit was made in 2017 (See Note 17).

Assets

Not all assets are associated with specific segments. Those assets specific to segments include receivables, certain identified property, plant and equipment (including rigs), investment in unconsolidated subsidiary and note receivable from unconsolidated subsidiary. The remaining assets, such as cash and equivalents, are considered to be shared among the segments and therefore reported in Unallocated and other.

	December 31,	
	2018	2017
Total assets:	(In millions)	
Deepwater	$2,757.9	$2,857.6
Jack-ups	4,153.8	4,173.7
Unallocated and other	1,206.0	1,427.0
Total	$8,117.7	$8,458.3

Disaggregation of Revenue and Geographical Information

The classifications of revenue among geographic areas in the tables which follow (in millions) were determined based on segment and physical location of assets. Because the Company evaluates performance primarily based on income from operations and the Company's offshore drilling rigs are mobile, classifications by area are dependent on the rigs' location at the time revenue is earned and may vary from one period to the next.

	Years ended December 31,		
	2018	2017	2016
Deepwater Revenue:			
United States	$157.0	$465.5	$823.7
Other [1]	1.1	2.4	3.8
Total	$158.1	$467.9	$827.5

[1] Other represents countries in which the Company operates that individually had revenue and long-lived assets representing less than 10% of total revenue or long-lived assets.

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	Years ended December 31,		
	2018	2017	2016
Jack-ups Revenue:			
Saudi Arabia	$319.9	$383.2	$363.9
Trinidad	115.4	127.0	130.4
Norway	86.5	193.8	312.6
United Kingdom	74.0	58.2	120.6
United States	31.0	45.2	29.1
Other (1)	6.1	0.1	59.1
Total	$632.9	$807.5	$1,015.7

(1) Other represents countries in which the Company operates that individually had revenue and long-lived assets representing less than 10% of total revenue or long-lived assets.

	Years ended December 31,		
	2018	2017	2016
Unallocated and Other Revenue:			
Saudi Arabia	$33.8	$7.4	$ —
Total	$33.8	$7.4	$ —

Revenue from Unallocated and other consists of transition services for ARO. Fees for these related services are recognized as the service is performed and such fees are billed on a monthly basis.

The classifications of long-lived assets among geographic areas in the table which follows (in millions) were determined based on the physical location of assets at the end of the periods presented below:

	December 31,	
	2018	2017
	(In millions)	
Long-lived assets:		
United States	$3,141.3	$3,065.6
Norway	810.8	862.8
Saudi Arabia	717.8	633.9
Trinidad	667.0	599.5
United Kingdom	328.3	1,067.2
Other (1)	577.0	354.6
Total	$6,242.2	$6,583.6

(1) Other represents countries in which the Company operates that individually had revenue and long-lived assets representing less than 10% of total revenue or long-lived assets.

NOTE 15 – GAIN ON SALE OF ASSETS TO UNCONSOLIDATED SUBSIDIARY

Effective October 1, 2018, the Company sold the Scooter Yeargain and the Hank Boswell to ARO for total cash consideration of $266.0 million. The book value of these assets was approximately $200.2 million. As a result of this sale transaction with ARO, the Company recognized a gain on the disposal of rigs in the amount of $65.8 million in 2018.

On October 17, 2017, pursuant to an Asset Transfer and Contribution Agreement, as amended, with ARO, the Company agreed to sell three rigs to ARO: the JP Bussell, the Bob Keller and the Gilbert Rowe and related assets for a total cash consideration of $357.7 million. The book value of these assets was approximately $200.3 million. As a result of this sale transaction with ARO, the Company recognized a gain on the disposal of rig assets in the amount of $157.4 million in 2017.

See Note 1 and Note 4 for more details of the ARO joint venture.

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NOTE 16 – MATERIAL CHARGES AND OTHER OPERATING ITEMS

Operating expenses for 2016 include (i) non-cash asset impairment charges totaling $34.3 million on five jack-up drilling units (see Note 8) and (ii) a $1.4 million reversal of an estimated liability for settlement of a withholding tax matter during a tax amnesty period which was related to a legal settlement for a 2014 termination of a contract for refurbishment work on the Rowan Gorilla III, as noted below in the 2015 period. Payment of such withholding taxes during the tax amnesty period resulted in the waiver of applicable penalties and interest.

NOTE 17 – SUPPLEMENTAL CASH FLOW INFORMATION

Non-cash investing and financing activities and other supplemental cash flow information follows (in millions):

	2018	2017	2016
Accrued but unpaid additions to property and equipment at December 31	$42.2	$21.4	$21.0
Cash interest payments	153.9	150.2	159.2
Income tax payments (refunds), net	33.1	30.0	38.1

On January 5, 2018, the Company purchased two 2013 Le Tourneau Super 116E jack-up rigs, the Bess Brants and Earnest Dees, formerly, P-59 and P-60, respectively, which were both delivered new into service in 2013, in a public auction from a subsidiary of Petroleo Brasileiro S.A. (“Petrobras”). The purchase price was $38.5 million per unit, or an aggregate $77.0 million, of which $7.7 million was paid as a deposit in December 2017. The remaining balance of $69.3 million as well as $1.5 million in transaction costs were paid in January 2018.

NOTE 18 – GUARANTEES OF REGISTERED SECURITIES

Rowan plc and its 100%-owned subsidiary, RCI, have entered into agreements providing for, among other things, the full, unconditional and irrevocable guarantee by Rowan plc of the prompt payment, when due, of any amount owed to the holders of RCI's Senior Notes.

The condensed consolidating financial information that follows is presented on the equity method of accounting in accordance with Rule 3-10 of Regulation S-X in connection with Rowan plc’s guarantee of the Senior Notes and reflects the corporate ownership structure as of December 31, 2018.

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Rowan Companies plc and Subsidiaries
Condensed Consolidating Statements of Operations
Year ended December 31, 2018
(In millions)

	Rowan plc (Parent)	RCI (Issuer)	Non-guarantor subsidiaries	Consolidating adjustments	Consolidated
REVENUE	$—	$4.9	$ 824.8	$ (4.9)	$ 824.8
COSTS AND EXPENSES:					
Direct operating costs (excluding items below)	—	—	682.7	—	682.7
Depreciation and amortization	—	—	388.9	—	388.9
Selling, general and administrative	25.7	0.6	74.7	(4.9)	96.1
Gain on sale of assets to unconsolidated subsidiary	—	—	(65.8)	—	(65.8)
Loss on disposals of property and equipment	—	3.7	8.4	—	12.1
Merger and related costs	8.9	—	—	—	8.9
Total costs and expenses	34.6	4.3	1,088.9	(4.9)	1,122.9
Equity in earnings of unconsolidated subsidiary	—	—	10.3	—	10.3
INCOME (LOSS) FROM OPERATIONS	(34.6)	0.6	(253.8)	—	(287.8)
OTHER INCOME (EXPENSE):					
Interest expense	—	(151.0)	(7.2)	1.9	(156.3)
Interest income	—	3.7	31.3	(1.9)	33.1
Other - net	4.9	(1.7)	8.8	—	12.0
Total other income (expense) - net	4.9	(149.0)	32.9	—	(111.2)
LOSS BEFORE INCOME TAXES	(29.7)	(148.4)	(220.9)	—	(399.0)
Provision (benefit) for income taxes	—	(87.6)	36.0	—	(51.6)
Equity in earnings (losses) of consolidated subsidiaries, net of tax	(317.7)	162.7	—	155.0	—
NET INCOME (LOSS)	$(347.4)	$101.9	$ (256.9)	$ 155.0	$ (347.4)

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Rowan Companies plc and Subsidiaries
Condensed Consolidating Statements of Operations
Year ended December 31, 2017
(In millions)

	Rowan plc (Parent)	RCI (Issuer)	Non-guarantor subsidiaries	Consolidating adjustments	Consolidated
REVENUE	$ —	$ 48.7	$ 1,283.2	$ (49.1)	$ 1,282.8
COSTS AND EXPENSES:					
Direct operating costs (excluding items below)	—	0.5	727.5	(43.0)	685.0
Depreciation and amortization	—	18.3	385.4	—	403.7
Selling, general and administrative	29.2	0.2	81.3	(6.1)	104.6
Gain on sale of assets to unconsolidated subsidiary	—	—	(157.4)	—	(157.4)
Loss on disposals of property and equipment	—	1.7	7.7	—	9.4
Total costs and expenses	29.2	20.7	1,044.5	(49.1)	1,045.3
Equity in earnings of unconsolidated subsidiary	—	—	0.9	—	0.9
INCOME (LOSS) FROM OPERATIONS	(29.2)	28.0	239.6	—	238.4
OTHER INCOME (EXPENSE):					
Interest expense	—	(155.8)	(0.5)	0.6	(155.7)
Interest income	—	3.6	12.4	(0.6)	15.4
Gain on extinguishment of debt	—	1.7	—	—	1.7
Other - net	20.4	(20.7)	(0.2)	—	(0.5)
Total other income (expense) - net	20.4	(171.2)	11.7	—	(139.1)
INCOME (LOSS) BEFORE INCOME TAXES	(8.8)	(143.2)	251.3	—	99.3
Provision (benefit) for income taxes	—	(8.2)	34.8	—	26.6
Equity in earnings of consolidated subsidiaries, net of tax	81.5	209.4	—	(290.9)	—
NET INCOME	$ 72.7	$ 74.4	$ 216.5	$ (290.9)	$ 72.7

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Rowan Companies plc and Subsidiaries
Condensed Consolidating Statements of Operations
Year ended December 31, 2016
(In millions)

	Rowan plc (Parent)	RCI (Issuer)	Non-guarantor subsidiaries	Consolidating adjustments	Consolidated
REVENUE	$ —	$ 40.4	$ 1,836.9	$ (34.1)	$ 1,843.2
COSTS AND EXPENSES:					
Direct operating costs (excluding items below)	—	12.4	796.4	(29.1)	779.7
Depreciation and amortization	—	19.2	382.7	1.0	402.9
Selling, general and administrative	28.5	5.5	74.2	(6.0)	102.2
Loss on disposals of property and equipment	—	0.9	7.8	—	8.7
Material charges and other operating items	—	—	32.9	—	32.9
Total costs and expenses	28.5	38.0	1,294.0	(34.1)	1,326.4
INCOME (LOSS) FROM OPERATIONS	(28.5)	2.4	542.9	—	516.8
OTHER INCOME (EXPENSE):					
Interest expense	—	(155.5)	(4.1)	4.1	(155.5)
Interest income	—	5.1	2.8	(4.1	