UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark one)

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

For the fiscal year ended December 31, 2014

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 001-36584

TRANSOCEAN PARTNERS LLC

(Exact name of registrant as specified in its charter)

Republic of the Marshall Islands (State or other jurisdiction of incorporation or organization)	66-0818288 (I.R.S. Employer Identification No.)
Deepwater House Kingswells Causeway Prime Four Business Park Aberdeen, Scotland, United Kingdom (Address of principal executive offices)	AB15 8PU (Zip Code)

Registrant's telephone number, including area code: +44 (1224) 945-100

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

Title of class	Exchange on which registered
Common units representing limited liability company interests	New York Stock Exchange

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

---

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

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

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

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

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

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

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer (do not check if a smaller reporting company) ☑ Smaller reporting company ☐

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

As of June 30, 2014, none of our units were outstanding. As of February 17, 2015, 41,379,310 common units and 27,586,207 subordinated units were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement to be filed with the U.S. Securities and Exchange Commission within 120 days of December 31, 2014, for its 2015 annual general meeting of shareholders, are incorporated by reference into Part III of this Form 10-K.

TRANSOCEAN PARTNERS LLC AND SUBSIDIARIES
INDEX TO ANNUAL REPORT ON FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2014

Forward-Looking Information

The statements included in this annual report regarding future financial performance and results of operations and other statements that are not historical facts are forward-looking statements within the meaning of Section 27A of the United States ("U.S.") Securities Act of 1933, as amended, and Section 21E of the U.S. Securities Exchange Act of 1934, as amended (the "Exchange Act"). Forward-looking statements in this annual report include, but are not limited to, statements about the following subjects:

- forecasts of our ability to make cash distributions on the units and the amount of any borrowings that may be necessary to make such distributions;
- forecasts of our results of operations and cash flow from operations, including revenues, revenue efficiency, costs and expenses;
- the offshore drilling market, including the impact of enhanced regulations in the jurisdictions in which we operate, supply and demand, utilization rates, dayrates, customer drilling programs, commodity prices, stacking of rigs, reactivation of rigs, effects of new rigs on the market and effects of declines in commodity prices and a downturn in the global economy or market outlook for our various geographical operating sectors and classes of rigs;
- customer drilling contracts, including contract backlog, force majeure provisions, contract commencements, contract extensions, contract terminations, contract option exercises, contract revenues, indemnity provisions, contract awards and rig mobilizations;
- liquidity and adequacy of cash flows for our obligations, including our ability to meet any future capital expenditure requirements;
- debt levels, including impacts of a financial and economic downturn;
- expected compliance with financing agreements and the expected effect of restrictive covenants in such agreements;
- tax matters, including our effective tax rate, changes in tax laws, treaties and regulations, tax assessments and liabilities for tax issues;
- legal and regulatory matters, including results and effects of legal proceedings and governmental audits and assessments, outcomes and effects of internal and governmental investigations, customs and environmental matters;
- our ability to maintain operating expenses at adequate and profitable levels;
- incurrence of cost overruns in the maintenance or other work performed on our drilling rigs;
- our ability to leverage Transocean Ltd.'s relationship and reputation in the offshore drilling industry;
- our ability to purchase drilling rigs from Transocean Ltd. in the future;
- our ability to make acquisitions that will enable us to increase our quarterly distributions per unit;
- insurance matters, including adequacy of insurance, renewal of insurance and insurance proceeds;
- effects of accounting changes and adoption of accounting policies; and
- investments in recruitment, retention and personnel development initiatives, pension plan and other postretirement benefit plan contributions, the timing of severance pay.

Forward-looking statements in this annual report are identifiable by use of the following words and other similar expressions:

- "anticipates"
- "believes"
- "budgets"
- "could"
- "estimates"
- "expects"
- "forecasts"
- "intends"
- "may"
- "might"
- "plans"
- "predicts"
- "projects"
- "scheduled"
- "should"

Such statements are subject to numerous risks, uncertainties and assumptions, including, but not limited to:

- those described in Part 1A. Risk Factors in this annual report on Form 10-K;
- the adequacy of and access to sources of liquidity;
- our inability to renew drilling contracts at comparable dayrates;
- operational performance;
- the impact of regulatory changes;
- the cancellation of drilling contracts currently included in our reported contract backlog;
- Changes in political, social and economic conditions;
- the effect and results of litigation, regulatory matters, settlements, audits, assessments and contingencies; and
- other factors discussed in this annual report and in our other filings with the U.S. Securities and Exchange Commission ("SEC"), which are available free of charge on the SEC website at *www.sec.gov*.

The foregoing risks and uncertainties are beyond our ability to control, and in many cases, we cannot predict the risks and uncertainties that could cause our actual results to differ materially from those indicated by the forward looking statements. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary materially from those indicated. All subsequent written and oral forward-looking statements attributable to us or to persons acting on our behalf are expressly qualified in their entirety by reference to these risks and uncertainties. You should not place undue reliance on forward-looking statements. Each forward–looking statement speaks only as of the date of the particular statement. We expressly disclaim any obligations or undertaking to release publicly any updates or revisions to any forward-looking statement to reflect any change in our expectations or beliefs with regard to the statement or any change in events, conditions or circumstances on which any forward-looking statement is based.

PART I

Item 1. Business

Overview

Transocean Partners LLC (together with its subsidiaries and predecessors, unless the context requires otherwise, "Transocean Partners", "we", "us" or "our") is a growth-oriented limited liability company formed by Transocean Ltd. (together with its subsidiaries and predecessors, unless the context requires otherwise, "Transocean"), one of the world's largest offshore drilling contractors, to own, operate and acquire modern, technologically advanced offshore drilling rigs. Our assets consist of 51 percent ownership interest in each of the entities that owns or operates the three ultra-deepwater drilling rigs that are currently operating in the U.S. Gulf of Mexico (each individually, a "RigCo", and collectively, the "RigCos"). Transocean owns the remaining 49 percent noncontrolling interest in each of the RigCos. We generate revenue through contract drilling services, which involves contracting our mobile offshore drilling fleet, related equipment and work crews on a dayrate basis to large international energy companies to drill oil and gas wells.

Our drilling rigs currently operate under long-term contracts with Chevron Corporation (together with its affiliates, "Chevron") and BP plc (together with its affiliates, "BP"), two leading international energy companies, with an average remaining contract term of approximately 3.5 years as of February 17, 2015. We believe that our drilling contracts will generate stable and reliable cash flows over their term. We depend on Transocean affiliates to operate our drilling units, manage our customer relationships, renew existing and obtain new drilling contracts and to perform other administrative support activities. We intend to use the relationships and expertise of Transocean to re-contract our fleet when the existing contracts expire and identify opportunities to expand our fleet through acquisitions.

Drilling Fleet

Fleet overview—At February 17, 2015, our fleet consisted of one ultra-deepwater semisubmersible rig and two ultra-deepwater drillships as follows:

					Contract term, dayrate and customer			
Rig	Year entered into service	Water depth (feet)	Drilling depth (feet)	Location	Start date	Completion date	Dayrate	Customer
Discoverer Clear Leader	2009	12,000	40,000	US Gulf of Mexico	November 2014	October 2018	$ 590,000	Chevron
Discoverer Inspiration	2010	12,000	40,000	US Gulf of Mexico	February 2010	March 2015	$ 523,000	Chevron
					March 2015	March 2020	$ 585,000	Chevron
Development Driller III	2009	7,500	37,500	US Gulf of Mexico	November 2009	November 2016	$ 431,000	BP

All of our drilling rigs are ultra-deepwater floaters, which we define as drilling units equipped with high pressure mud pumps and the capability to drill in water depths of 7,500 feet or greater. Our drilling rigs are mobile and can be moved to new locations in response to customer demand. They are designed to operate in locations away from port for extended periods of time and have living quarters for the crews, a helicopter landing deck and storage space for drill pipe, riser and drilling supplies.

Our drilling rigs are classed by either Det Norske Veritas ("DNV") or the American Bureau of Shipping ("ABS"), and all hold valid classification and statutory certificates. Every offshore drilling rig is a registered marine vessel and must be "classed" by a classification society. The classification society certifies that the drilling rig is "in-class," signifying that such drilling rig has been built and maintained in accordance with the rules of the classification society and complies with applicable rules and regulations of the drilling rig's country of registry and the international conventions of which that country is a member. Classification societies are considered non-governmental organizations that establish and maintain technical standards for the construction and operation of ships and offshore structures. DNV and ABS are also recognized by flag states as entities authorized to conduct regular statutory surveys as part of the flag state requirements.

Drillships—Drillships are generally self-propelled vessels, shaped like conventional ships, and are the most mobile of the major rig types. Both of our high-specification drillships are equipped with a computer-controlled dynamic positioning thruster system, which allows them to maintain position without anchors through the use of their onboard propulsion and station-keeping systems. Ultra-deepwater drillships typically have greater deck load and storage capacity than semisubmersible rigs. This enables them to carry more supplies on board, which provides logistical and resupply efficiency benefits for customers. However, drillships are better suited to operations in calmer sea conditions and typically do not operate in areas considered to be harsh environments. Our drillships are equipped with Transocean's patented dual-activity technology, which employs structures, equipment and techniques using two drilling stations within a dual derrick to allow these drillships to perform simultaneous tasks in a parallel, rather than a sequential, manner, reducing critical path activity, to improve efficiency in both exploration and development drilling.

Discoverer Inspiration and *Discoverer Clear Leader* are sixth generation, dynamically positioned, ultra-deepwater drillships. Each of these double-hulled, Enhanced Enterprise-class drillships features advanced offshore drilling technology, including an enhanced top drive system, an expanded high-pressure mud-pump system, a variable deckload of 20,000 metric tons, completion capabilities and Transocean's patented dual-activity technology. Our Enhanced Enterprise-class drillships offer improved reliability, increased pipe handling capacity, two blowout preventer ("BOP") stacks and flexible fluid capabilities. The primary derrick is rated to 2.5 million pounds, which enables increased water depth and drilling depth and heavier casing loads. *Discoverer Inspiration* and *Discoverer Clear Leader* also have crude oil storage capacity for up to 120,000 barrels that can be used during testing. Both rigs are capable of operating in moderate environments and are equipped for drilling in water depths of up to 12,000 feet.

Semisubmersible—Semisubmersibles are floating vessels that can be partially submerged by means of a water ballast system such that the lower column sections and pontoons are below the water surface during drilling operations. These rigs are capable of maintaining their position over a well either through a computer-controlled dynamic positioning thruster system, as is the case for *Development Driller III*, or the use of an anchoring system. Although most semisubmersible rigs are relocated with the assistance of tugs, some units, including *Development Driller III*, are self-propelled and move between locations under their own power when afloat on pontoons. In addition, semisubmersibles are capable of operating in rougher sea conditions than drillships.

Development Driller III is a dynamically positioned, ultra-deepwater semi-submersible drilling rig. It features advanced offshore drilling technology, including a dual mud system design, which allows preparation, storage and offloading of two separate drilling fluids, variable deckload of 7,000 metric tons and Transocean's patented dual-activity drilling technology. *Development Driller III* can deploy mooring or operate with dynamic positioning. The rig has a 125-ton heave-compensated winch that can be utilized offline with drilling operations for subsea tree handling and running. *Development Driller III* is equipped for drilling in water depths up to 7,500 feet, upgradable to 10,000 feet, and for drilling wells up to 37,500 feet total depth.

Relationship with Transocean

One of our principal strengths is our relationship with Transocean. Transocean is a leading international provider of offshore contract drilling services for oil and gas wells. As of February 17, 2015, Transocean owned or had partial ownership interests in and operated 71 mobile offshore drilling units, including our drilling rigs. As of February 17, 2015, Transocean's fleet, including the rigs in our fleet, consisted of 44 high-specification floaters (ultra-deepwater, deepwater and harsh environment semisubmersibles and drillships), 17 midwater floaters and 10 high-specification jackups. At such date, Transocean also had seven ultra-deepwater drillships and five high-specification jackups under construction or under contract to be constructed.

Transocean retains a significant interest in us through its ownership of common and subordinated units, representing an aggregate 70.8 percent limited liability company interest in us, and all of our incentive distribution rights. Transocean Partners Holdings Limited (the "Transocean Member"), an indirect wholly owned subsidiary of Transocean Ltd., holds the Transocean Member interest, which is a non-economic interest in us that includes the right to appoint three of the seven members of our board of directors. Under our limited liability company agreement, common unitholders that own 50 percent or more of our common units have the ability to request that cumulative voting be in effect for the election of elected directors. Cumulative voting is an irrevocable election that allows for the unitholder to allocate its votes cumulatively, rather than proportionally. Therefore, for so long as Transocean owns 50 percent or more of our common units, it will have the ability to request that cumulative voting be in effect for the election of elected directors, which would enable Transocean to elect one or more of the elected directors even after it owns less than 50 percent of our common units. As a result, if cumulative voting was in effect, Transocean would have the ability to appoint the majority of our board as long as it retains at least 20 percent of our common units. The directors appointed by Transocean may designate a member of the board of directors to be the chairman of the board of directors. Specific rights of the Transocean Member are designated in our limited liability company agreement.

We believe that our relationship with Transocean will provide us with access to leading international energy companies, as well as suppliers and other key service providers for our industry. We also believe that Transocean's operational and managerial expertise will enable us to compete more effectively for contract opportunities than other contract drilling companies similar in size to us. In addition to the drillships discussed below, Transocean has a number of newer rigs that are operating under long-term drilling contracts and rigs under construction. Although Transocean is not obligated to offer these rigs to us, we believe that these rigs would be particularly suitable for future contribution or sale to us.

On August 5, 2014, we entered into an omnibus agreement (the "Omnibus Agreement") with Transocean and certain of its affiliates. Under the Omnibus Agreement, Transocean granted us a right of first offer for its remaining ownership interests in each of the RigCos should Transocean decide to sell such interests. By August 5, 2019, Transocean also is required to offer us the opportunity to purchase, subject to requisite government and other third-party consents, not less than a 51 percent interest in any four of the six ultra-deepwater drillships listed below at a purchase price equal to the greater of the fair market value, taking into account the anticipated cash flows under the associated drilling contracts, or the all-in construction cost, plus transaction costs. Transocean will select which of these drillships it will offer to us, the timing of the offers and whether it will offer us the opportunity to purchase a greater than 51 percent interest in any offered drillship.

					Contract term, dayrate and customer			
Rig	Expected construction completion	Water depth (feet)	Drilling depth (feet)	Location	Start date	Completion date	Dayrate	Customer
Deepwater Invictus	Completed	12,000	40,000	US Gulf of Mexico	3Q2014	2Q2017	$ 595,000	BHP Billiton
Deepwater Thalassa	1Q2016	12,000	40,000	TBA	1Q2016	4Q2025	$ 519,000	Shell
Deepwater Proteus	2Q2016	12,000	40,000	TBA	2Q2016	2Q2026	$ 519,000	Shell
Deepwater Pontus	1Q2017	12,000	40,000	TBA	1Q2017	1Q2026	$ 519,000	Shell
Deepwater Poseidon	2Q2017	12,000	40,000	TBA	2Q2017	2Q2027	$ 519,000	Shell
Deepwater Conqueror	4Q2016	12,000	40,000	U.S. Gulf of Mexico	4Q2016	4Q2021	$ 599,000	Chevron

The consummation and timing of any acquisitions from Transocean will depend upon, among other things, our ability to obtain any necessary consents, the determination that the acquisition is appropriate for our business at that particular time, our ability to agree on mutually acceptable terms of purchase, including price, and our ability to obtain financing on acceptable terms.

In addition, Transocean agreed not to acquire, own or operate any new drilling rig or contract for any drilling rig, in each case that was constructed in 2009 or later and is operating under a contract for five or more years ("Five-Year Drilling Rigs"), subject to certain exceptions, without offering us the opportunity to purchase such rig. We also agreed not to acquire, own, operate or contract for any drilling rig that is not a Five-Year Drilling Rig, subject to certain exceptions, without first offering the contract to Transocean.

Business Strategies

Our primary business objectives are to operate and maintain our fleet to generate stable cash flows and increase our quarterly cash distributions per unit over time. We intend to accomplish these objectives by executing the following business strategies:

Grow through strategic acquisitions—We intend to pursue strategic opportunities to grow our company and fleet through acquisitions from Transocean or third parties that will enable us to increase our quarterly distributions per unit. Pursuant to the Omnibus Agreement, Transocean is required, under certain circumstances, to offer us the opportunity to purchase its remaining interests in one or more of the RigCos, as well as certain drilling rigs, including a majority ownership interest in four of the ultra-deepwater drillships that are currently under construction and are supported by long-term contracts.

Pursue assets with contracts that help maintain stable cash flows—We are focused on generating and maintaining stable cash flows by pursuing drilling rigs operated under long-term contracts with creditworthy counterparties. We believe that employing our rigs under long-term contracts will improve the stability and predictability of our cash flows and should also contribute to our growth strategy by facilitating our access to debt and equity financing. We also believe that our relationship with Transocean will enhance our ability to compete for contract opportunities.

Conduct safe, efficient and reliable operations—We participate in Transocean's programs designed to maintain and improve the safety, reliability and efficiency of all our operations, which are vital to our ability to retain and attract our customers. We believe that our relationship with Transocean and our relatively young and high-specification fleet will enable us to operate safely, efficiently and cost effectively. We expect that these factors will enhance our ability to secure additional long-term contracts and extend existing contracts, enabling us to maintain high asset utilization.

Maintain a modern and reliable fleet—We have one of the most capable and technologically advanced fleets in the industry. We plan to invest both in growing our modern and reliable fleet and in continually maintaining the quality and operational integrity of our assets. We believe that investing in high-quality assets with proven and reliable drilling rig technology is an important component in our strategy to provide our customers with safe and reliable operations and services.

Market

Although our contract drilling services operations are currently concentrated in the U.S. Gulf of Mexico, we can provide our services anywhere in the world. We operate in a single, global offshore drilling market, given that our drilling rigs are mobile assets we are able to respond to prevailing market conditions, as we have the ability to mobilize our drilling rigs between regions based on customer contracting requirements or reposition the drilling rigs to capture demand.

The market for offshore drilling rigs and associated services reflects oil companies' demand for equipment for drilling exploration, appraisal and development wells and for performing maintenance on existing production wells. Activity levels of exploration and production companies and their associated capital expenditures are to a large extent driven by the worldwide demand for energy, including crude oil and natural gas. Demand and supply for hydrocarbons drives commodity prices which in turn impact exploration and production companies' ability to fund investments in exploration, development and production activities.

In addition to absolute levels of demand from oil companies, the offshore drilling industry has experienced significant improvements in the technical specifications for rigs required for many regions. Factors such as water depth, more advanced well designs, deeper drilling depth, high pressure and temperature, sub-salt, and harsh environments, as well as heightened regulatory standards, are driving the need for more sophisticated drilling units. We expect the production of hydrocarbons from these more challenging environments to support the demand for modern, technologically advanced mobile offshore drilling units.

The global offshore drilling market is becoming more specialized as new technology enables drilling activities in deeper waters and harsher environments, facilitating exploration and development drilling in new geographical areas. As a result, drilling contractors have been turning their focus to water depth, technical capacities and rig types required to meet changes in rig requirements from oil companies.

Notwithstanding the recent cyclical downturn, deepwater oil and gas production has increased in importance. Evolving drilling technology combined with a period of continued growth in energy demand has led to the discovery of several new deepwater basins and plays in the past several years. These discoveries marked the beginning of our customers' increasing strategic focus on deepwater and represent a backlog of deepwater development opportunities, with Brazil, the U.S. Gulf of Mexico and West Africa being the key ultra-deepwater provinces. Outside of these core regions, activity has also increased in the Mediterranean, East Africa, Mexico and Asia, among other areas. Because offshore discoveries have been concentrated in deepwater, the majority of the global ultra-deepwater fleet operates in this space; however, the design of ultra-deepwater drilling rigs enables them to operate in ultra-deepwater areas, which have experienced growing interest in exploration and development activity. Ultra-deepwater rigs represent the newest and most modern class of the offshore fleet and have capabilities that are attractive to exploration and production companies operating in many water depths.

Additionally, licensing activity during the past several years demonstrates the increased interest in deepwater as exploration and production companies look to explore new frontiers. This significant reloading of exploration portfolios, particularly by the major oil companies, reflects the strategic importance of deepwater as companies look to areas they can access and that are prospective for material discoveries. Deepwater is, therefore, an increasingly important part of the major oil companies' long-term strategies.

Although our long-term view of the offshore drilling market remains favorable, particularly for high-specification assets, we expect the near to medium term to be challenging given customers' decisions to focus on capital allocation, reduce costs and delay various exploration and development programs. The significant and rapid decline in oil and natural gas prices has accelerated the rapid decrease in demand in all markets. We currently expect the pace of contracting for the global floater fleet to remain slow in the near to medium term, resulting in excess capacity, lower dayrates and idle time for some rigs. Additionally, this excess capacity may result in some lower capability assets in the industry being permanently retired, ultimately reducing the available supply of drilling rigs, all else being equal.

Financial Information about Geographic Areas

For each of the three years ended December 31, 2014, all of our operating revenues were earned in the U.S. At December 31, 2014 and 2013, all of our long-lived assets were located in the U.S.

Drilling Contracts

Our contracts to provide offshore drilling services are individually negotiated and vary in their terms and provisions. Our current drilling contracts were directly negotiated. We expect to obtain most of our future drilling contracts through competitive bidding against other contractors and direct negotiations with operators. Our drilling contracts generally provide for payment on a dayrate basis, with higher rates for periods while the drilling unit is operating and lower rates or zero rates for periods of mobilization or when drilling operations are interrupted or restricted by equipment breakdowns, adverse environmental conditions or other conditions beyond our control.

A dayrate drilling contract generally extends over a period of time covering either the drilling of a single well or group of wells or covering a stated term. Certain of our drilling contracts with customers may be cancelable for the convenience of the customer only upon payment of an early termination payment. Such payments, however, may not fully compensate us for the loss of the contract. Contracts also customarily provide for either automatic termination or termination at the option of the customer typically without the payment of any termination fee, under various circumstances such as non-performance, in the event of extended downtime or impaired performance caused by equipment or operational issues, or periods of extended downtime due to force majeure events. Many of these events are beyond our control. The contract term in some instances may be extended by the customer exercising options for the drilling of additional wells or for an additional term. Our contracts also include a provision that allows the customer to extend the contract to finish drilling a well in progress. During periods of depressed market conditions, our customers may seek to renegotiate firm drilling contracts to reduce their obligations or may seek to repudiate their contracts. Suspension of drilling contracts will result in the reduction in or loss of dayrate for the period of the suspension. If our customers cancel some of our contracts and we are unable to secure new contracts on a timely basis and on substantially similar terms, or if contracts are suspended for an extended period of time or if a number of our contracts are renegotiated, it could adversely affect our consolidated results of operations or cash flows. See "Risk Factors—Risks Inherent in Our Business—Our drilling contracts may be terminated due to a number of events."

Consistent with standard industry practice, our customers generally assume, and indemnify us against, well control and subsurface risks under dayrate drilling contracts. Under all of our current drilling contracts, the operator indemnifies us for pollution damages in connection with reservoir fluids stemming from operations under the contract and we indemnify the operator for pollution from substances in our control that originate from the rig, such as diesel used onboard the rig or other fluids stored onboard the rig and above the water surface. Also, under all of our current drilling contracts, the operator indemnifies us against damage to the well or reservoir and loss of subsurface oil and gas and the cost of bringing the well under control. However, our drilling contracts are individually negotiated, and the degree of indemnification we receive from the operator against the liabilities discussed above can vary from contract to contract, based on market conditions and customer requirements existing when the contract was negotiated. In some instances, we have agreed and may contractually agree upon certain limits to our indemnification rights and can be responsible for damages up to a specified maximum dollar amount, which amount is usually $5 million or less, although the amount can be greater depending on the nature of our liability. In some instances in which we are indemnified for damages to the well, we have the responsibility to re-drill the well at a reduced dayrate. Notwithstanding a contractual indemnity from a customer, there can be no assurance that our customers will be financially able to indemnify us or will otherwise honor their contractual indemnity obligations. See "Item Risk Factors—Risks Inherent in Our Business—Our business involves numerous operating hazards, and our insurance and indemnities from our customers may not be adequate to cover potential losses from our operations."

The interpretation and enforceability of a contractual indemnity depends upon the specific facts and circumstances involved, as governed by applicable laws, and may ultimately need to be decided by a court or other proceeding which will need to consider the specific contract language, the facts and applicable laws. In connection with the Macondo well incident, although certain aspects of its contractual indemnity was enforced, a court refused to enforce Transocean's indemnity in respect of certain penalties and punitive damages under the Clean Water Act. The law generally considers contractual indemnity for criminal fines and penalties to be against public policy. The inability or other failure of our customers to fulfill their indemnification obligations to us could have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. Courts also restrict indemnification for criminal fines and penalties.

The terms of the drilling contracts for *Discoverer Inspiration*, *Discoverer Clear Leader* and *Development Driller III* generally conform to the summary description above. In addition, Transocean has provided a financial and performance guarantee to our customer, BP, for the contract for *Development Driller III*. Transocean is under no obligation to continue to provide such guarantees in the future or to extend the current guarantee for any amendment or extension of the current drilling contract.

Seasonality

In general, seasonal factors do not have a significant direct effect on our business. Our drilling rigs are currently operating in the U.S. Gulf of Mexico, which experiences hurricane season between June 1 and November 30 each year. Although weather conditions during parts of the year could adversely impact the operation of our rigs, generally such operational interruptions do not have a significant impact on our revenues. See "—Drilling Contracts."

Customers

For the year ended December 31, 2014, our customers were Chevron and BP, accounting for approximately 67 percent and 33 percent, respectively, of our combined operating revenues (see "Risk Factors—Risks Inherent in Our Business—We currently derive all our revenues from two customers, and the loss of either of these customers or a dispute that leads to a loss of a customer could have a material adverse impact on our financial condition, results of operations and cash flows and may reduce cash available for distribution"). Typical customers for the types of rigs included in our fleet are leading international oil companies or their affiliates, government controlled oil companies and independent oil companies.

Competition

The offshore drilling market is highly competitive with numerous industry participants, none of which has a dominant market share. Drilling contracts are generally awarded through competitive bidding processes, where our customers and potential customers' main considerations are price, quality and technical capability of services and equipment. Industry supply and demand economics play an important role in the contractual terms, including the dayrates, we and our customers ultimately agree to. As a result of these economic forces, in general, and the increased number of newbuild units entering the drilling market, specifically, our ability to obtain future drilling contracts, if at all, may be subject to increased competition and impact our dayrates and utilization rates. See "Risk Factors—Risks Inherent in Our Business—The offshore drilling industry is highly competitive and cyclical, with intense price competition."

In recent years, oil companies have placed increased emphasis on exploring for hydrocarbons in deeper waters. This deepwater focus is due, in part, to technological developments that have made such exploration more feasible and cost effective. Therefore, water depth capability is a key component in determining rig suitability for a particular drilling project. We believe that our fleet of recently constructed high-specification drilling rigs provides us with a competitive advantage over competitors with older fleets.

Employees

We require highly skilled personnel to operate our drilling units. Consequently, Transocean conducts extensive personnel recruiting, training and safety programs for our crews. At December 31, 2014, there were approximately 570 employees associated with the operation of the rigs in our current fleet, substantially all of which are Transocean employees that will provide services to us under our contracts with Transocean. None of the employees associated with our operations are members of labor unions and our relationship with our labor force is good, although portions of Transocean's global workforce are unionized in parts of the world where we could operate in the future.

Legislation has been introduced in the U.S. Congress that could encourage additional unionization efforts in the U.S., as well as increase the chances that such efforts succeed. Additional unionization efforts, if successful, new collective bargaining agreements or work stoppages could materially increase our labor costs and operating restrictions. See "Risk Factors—Any operations outside the U.S. may involve additional risks."

Joint Venture, Agency and Sponsorship Relationships

In some areas of the world where our drilling rigs may operate in the future, local customs and practice or governmental requirements necessitate the formation of joint ventures with local participation. We may or may not control these joint ventures. Local laws or customs in some areas of the world also effectively mandate establishment of a relationship with a local agent or sponsor. When appropriate in these areas, we will enter into agency or sponsorship agreements.

Environmental Compliance

Overview—Our operations are subject to a variety of global environmental regulations. We monitor our compliance with environmental regulation in each country of operation and, while we see an increase in general environmental regulation, we have made and will continue to make the required expenditures to comply with current and future environmental requirements. Together with Transocean, we make expenditures to further our commitment to environmental improvement and the setting of a global environmental standard as part of Transocean's wider corporate responsibility effort. We assess the environmental impacts of our business, focusing on the areas of greenhouse gas emissions, climate change, discharges and waste management. Our actions are designed to reduce risk in our current and future operations, to promote sound environmental management and to create a proactive environmental program. To date, we have not incurred material costs in order to comply with recent environmental legislation, and we do not believe that our compliance with such requirements will have a material adverse effect on our competitive position, consolidated results of operations or cash flows.

For a discussion of the effects of environmental regulation, see "Risk Factors—Risks Inherent in Our Business—Compliance with or breach of environmental laws can be costly, expose us to liability and could limit our operations" and "—Regulation of greenhouse gases and climate change could have a negative impact on our business."

Consent Decree and EPA Agreement—On January 3, 2013, Transocean entered into certain agreement with the U.S. Department of Justice (the "DOJ") to resolve certain outstanding civil and potential criminal charges against Transocean arising from the Macondo well incident, including a civil consent decree ("Consent Decree"), and subsequently entered into an administrative agreement with the U.S. Environmental Protection Agency (the "EPA Agreement"). We are not party to the Consent Decree or the EPA Agreement. Because we are an affiliate of Transocean, however, our operations in the waters of the U.S. are subject to the safety, environmental, reporting, operational and other requirements of the Consent Decree and the EPA Agreement. These requirements are in addition to the regulations applicable to all industry participants and may add additional costs and liabilities.

Pursuant to the Consent Decree, Transocean agreed to take specified actions relating to operations in U.S. waters, including, among other things, the design and implementation of, and compliance with, additional systems and procedures; blowout preventer certification and reports; measures to strengthen well control competencies, drilling monitoring, recordkeeping, incident reporting, risk management and oil spill training, exercises and response planning; communication with operators; alarm systems; transparency and responsibility for matters relating to the Consent Decree; and technology innovation, with a first emphasis on more efficient, reliable blowout preventers.

The Consent Decree also provides for the appointment of (i) an independent auditor to review, audit and report on Transocean's compliance with the injunctive provisions of the Consent Decree and (ii) an independent process safety consultant to review, report on and assist with respect to the process safety aspects of the Consent Decree, including operational risk identification and risk management. The Consent Decree requires certain plans, reports and submissions be made and be acceptable to the U.S. and also requires certain publicly available filings.

In the EPA Agreement, Transocean agreed to, among other things, continue the implementation of certain programs and systems; comply with certain employment and contracting procedures; engage independent compliance auditors and a process safety consultant; and give reports and notices with respect to various matters. Subject to certain exceptions, the EPA Agreement prohibits Transocean and its affiliates from entering into, extending or engaging in certain business relationships with individuals or entities that are debarred, suspended, proposed for debarment or similarly restricted. In addition, if we or Transocean fail to comply with the terms of the EPA Agreement, we may be subject to suspension, debarment or statutory disqualification.

Available Information

Our website address is *www.transoceanpartners.com*. Information contained on or accessible from our website is not incorporated by reference into this annual report on Form 10-K and should not be considered a part of this report or any other filing that we make with the SEC. We make available on this website free of charge, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports as soon as reasonably practicable after we electronically file those materials with, or furnish those materials to, the SEC. You may also find on our website information related to our corporate governance, board committees and company code of business conduct and ethics. The SEC also maintains a website, *www.sec.gov*, which contains reports, proxy statements and other information regarding SEC registrants, including us.

We intend to satisfy the requirement under Item 5.05 of Form 8-K to disclose any amendments to our Code of Integrity and any waiver from any provision of our Code of Integrity by posting such information in the Corporate Governance section of our website at *www.transoceanpartners.com*.

Item 1A. Risk Factors

Risks related to our business

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses to enable us to pay the minimum quarterly distribution on our common units and subordinated units.

We may not have sufficient cash from operations to pay the minimum quarterly distribution of $0.3625 per unit, or $1.45 per unit on an annualized basis, to the holders of our common units and subordinated units, which will require us to have available cash of approximately $25 million per quarter, or $100 million per year. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which may fluctuate from quarter to quarter based on the risks described in this section, including, among other things:

- our ability to re-contract our drilling rigs in their current configuration upon expiration or termination of an existing drilling contract and the dayrates we obtain under such contracts;
- the dayrates we obtain under our drilling contracts;
- the level of reimbursable revenues and expenses;
- the level of our rig operating costs, such as the cost of crews, repairs, maintenance and insurance;
- the effect of governmental regulations and maritime self-regulatory organization standards on the conduct of our business;
- rig downtime or less than full utilization, which would result in a reduction of revenues under our drilling contracts;
- changes in local income tax rates, tax treaties and tax laws;
- the timeliness of payments from customers under drilling contracts;
- time spent mobilizing drilling rigs to the customer location;
- resolution of tax assessments;
- currency exchange rate fluctuations and currency controls; and
- prevailing global economic and market conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

- the level and timing of capital expenditures;
- the level of our operating, maintenance and rig and shore-based general and administrative expenses, including reimbursements to Transocean and its affiliates for services provided to us and additional expenses we will incur as a result of being a public company;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- the cost of acquisitions, if any;
- our ability to borrow funds and access capital markets;
- restrictions on distributions contained in our debt agreements; and
- the amount of cash reserves, including reserves for future maintenance and replacement capital expenditures, working capital and other matters, established by our board of directors.

We may be unable to renew or obtain new and favorable drilling contracts for rigs whose contracts are expiring or are terminated, which could adversely affect our revenues and profitability.

Our ability to renew expiring drilling contracts or obtain new drilling contracts will depend on the prevailing market conditions at the time. If we are unable to obtain new drilling contracts, if new drilling contracts are entered into at dayrates substantially below the existing dayrates or on terms otherwise less favorable compared to existing contract terms or if our customers request modifications of our drilling rigs in connection with new drilling contracts, our revenues and profitability could be adversely affected.

The offshore drilling market in which we compete experiences fluctuations in the demand for drilling services, as measured by the level of exploration and development expenditures. The existing drilling contracts for our drilling rigs are scheduled to expire from 2016 through 2020. We cannot guarantee that we will be able to obtain drilling contracts for our rigs upon the completion or termination of their current contracts or that there will not be a gap in employment of the rigs between current contracts and subsequent contracts. In particular, if oil and natural gas prices are low, or it is expected that such prices will decrease in the future, at a time when we are seeking to arrange drilling contracts for our rigs, we may be unable to obtain drilling contracts at attractive dayrates or at all. In addition, our customers may require modifications to our drilling rigs in connection with a new drilling contract and, depending on the market conditions at the time we enter into the contract, we may not be reimbursed for some or all of such modifications.

If the dayrates which we receive for the reemployment of our current drilling rigs are less favorable, we will recognize less revenue from their operations. Our ability to meet our cash flow obligations will depend on our ability to consistently secure drilling contracts for our drilling rigs at sufficiently high dayrates. We cannot predict the future level of demand for our services or future conditions in the oil and gas industry. If oil and gas companies do not continue to maintain or increase exploration, development and production expenditures, we may have difficulty securing drilling contracts, or we may be forced to enter into contracts at unattractive dayrates, which would adversely affect our ability to make distributions to our unitholders.

The amount of cash we have available for distribution to holders of our common and subordinated units depends primarily on our cash flow rather than on our profitability, which may prevent us from making distributions, even during periods in which we record net income.

The amount of cash we have available for distribution depends primarily upon our cash flow rather than on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

Our ability to grow may be adversely affected by our cash distribution policy.

Our cash distribution policy, which is consistent with our limited liability company agreement, requires us to distribute all of our available cash each quarter. In determining the amount of available cash each quarter, our board of directors will approve the amount of cash reserves to set aside, including reserves for anticipated maintenance and replacement capital expenditures, working capital and other matters. We will also rely upon external financing sources, including commercial borrowings, to fund our capital expenditures. To the extent we do not have sufficient cash reserves or are unable to obtain financing, our cash distribution policy may significantly impair our ability to meet our financial needs or to grow. Accordingly, our growth may not be as fast as businesses that reinvest their available cash to expand ongoing operations.

In establishing cash reserves, our board of directors may reduce the amount of cash available for distribution to our unitholders.

Our limited liability company agreement requires our board of directors to deduct from operating surplus cash reserves that it determines are necessary to fund our future operating expenditures. Our limited liability company agreement also permits our board of directors to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party, or to provide funds for future distributions to our unitholders. In addition, our limited liability company agreement requires our board of directors each quarter to deduct from operating surplus estimated maintenance and replacement capital expenditures, as opposed to actual maintenance and replacement capital expenditures, which could reduce the amount of available cash for distribution. The amount of estimated maintenance and replacement capital expenditures deducted from operating surplus is subject to review and change by our board of directors at least once a year, provided that any change must be approved by the conflicts committee of our board of directors. These cash reserves affect the amount of cash available for distribution to unitholders.

We must make substantial capital and operating expenditures to maintain the operating capacity of our fleet and our competitiveness, to comply with laws and the applicable regulations and standards of governmental authorities and organizations, and to execute our growth plan, each of which could negatively affect our financial condition, results of operations and cash flows and reduce cash available for distribution.

We must make substantial capital and operating expenditures to maintain and replace, over the long-term, the operating capacity of our fleet. We estimate that maintenance and replacement capital expenditures will average approximately $67 million per year, including amounts for replacing current drilling rigs at the end of their useful lives. Maintenance and replacement capital expenditures include capital expenditures for maintenance, including special classification surveys, and capital expenditures associated with modifying an existing drilling rig, including to upgrade its technology, extending the useful life of existing drilling rigs, acquiring a new drilling rig or otherwise replacing current drilling rigs at the end of their useful lives to the extent these expenditures are incurred to maintain or replace the operating capacity of our fleet. These expenditures could vary significantly from quarter to quarter, and from year to year, and could increase as a result of changes in the following:

- the cost of labor and materials;
- customer requirements;
- fleet size;
- the cost of replacement drilling rigs;
- the cost of replacement parts for existing drilling rigs;
- the geographic location of the drilling rigs;
- length of drilling contracts;
- governmental regulations and maritime self-regulatory organization and technical standards relating to safety, security or the environment;
- compliance with Transocean's consent decree with the DOJ (the "Consent Decree"), Transocean's administrative agreement with the U.S. Environmental Protection Agency (the "EPA Agreement") and other governmental agreements; and
- industry standards.

Changes in offshore drilling technology, customer requirements for new or upgraded equipment and competition within our industry may require us to make significant capital expenditures in order to maintain our competitiveness. Our competitors may have greater financial and other resources than we have, which may enable them to make technological improvements to existing equipment or replace equipment that becomes obsolete. In addition, changes in governmental regulations, safety or other equipment standards, as well as compliance with standards imposed by maritime self-regulatory organizations, may require us to make additional unforeseen capital expenditures. As a result, we may be required to take our rigs out of service for extended periods of time, with corresponding losses of revenues, in order to make such alterations or to add such equipment. In the future, market conditions may not justify these expenditures or enable us to operate our older rigs profitably during the remainder of their economic lives.

If capital expenditures are financed through cash from operations or by issuing debt or equity securities, our ability to make cash distributions may be diminished, our financial leverage could increase or our unitholders could be diluted.

In order to maintain our fleet and execute our growth plan, we may require additional capital in the future. If we are unable to fund capital expenditures with cash flow from operations, we may be required to either incur additional borrowings or raise capital through the sale of debt or equity securities. Our ability to access the capital markets for future offerings may be limited by our financial condition at the time, by changes in laws and regulations, or interpretation thereof, and by adverse market conditions resulting from, among other things, general economic conditions, changes in the offshore drilling industry and contingencies and uncertainties that are beyond our control. Failure to obtain the funds for future capital expenditures could have a material adverse effect on our business, results of operations and financial condition and on our ability to make cash distributions. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional equity securities may result in significant unitholder dilution and would increase the aggregate amount of cash required to pay the minimum quarterly distribution to unitholders, both of which could have a material adverse effect on our ability to make cash distributions.

We currently derive all our revenues from two customers, and the loss of either of these customers or a dispute that leads to a loss of a customer could have a material adverse impact on our financial condition, results of operations and cash flows and may reduce cash available for distribution.

We currently derive all of our revenues and cash flow from two customers. For the year ended December 31, 2014, Chevron and BP accounted for 67 percent and 33 percent, respectively, of our total revenues. All of our drilling contracts have fixed terms, but may be terminated early due to certain events or might nevertheless be lost in the event of unanticipated developments, such as the deterioration in the general business or financial condition of a customer, resulting in its inability to meet its obligations under our contracts. Transocean's relationship with BP, whose affiliate was the operator of the Macondo well, has been and could continue to be negatively impacted by the Macondo well incident. The loss of any customers, drilling contracts or drilling rigs, or a decline in payments under any of our drilling contracts, could have a material adverse effect on our business, financial condition, results of operations or cash flows and could reduce our cash available for distribution.

In addition, 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 and may include, among other things, general economic conditions, the condition of the offshore drilling industry, prevailing prices for oil and natural gas, the overall financial condition of the counterparty, the dayrates received and the level of expenses necessary to maintain drilling activities. In addition, in depressed market conditions, our customers may no longer need a drilling rig that is currently under contract or may be able to obtain a comparable drilling rig at a lower dayrate. Should a 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, results of operations and cash available for distribution.

Any limitation in the availability or operation of any of our three drilling rigs could have a material adverse effect on our business, results of operations and financial condition and could significantly reduce our ability to make distributions to our unitholders.

Our fleet currently consists of two drillships and one semi-submersible drilling rig. Our limited number of rigs makes us more susceptible to incremental loss in the event of any downtime with respect to any rig. If any of our drilling rigs is unable to generate revenues as a result of sustained periods of downtime or the expiration or termination of its drilling contracts, and we are unable to recontract such rig, our financial condition, results of operations or cash flows could be materially adversely affected and our cash available for distribution could be reduced.

Our revenues are currently derived solely from assets that are operating in the U.S. Gulf of Mexico, making us vulnerable to risks associated with operating in that single geographic area.

Currently, all of our operations are conducted in the U.S. Gulf of Mexico. This concentration could disproportionately expose us to operational and regulatory risk or other adverse developments in this area, including, for example, delays or decreases in the availability of equipment, facilities or services, severe weather, including tropical storms and hurricanes, and changes in the regulatory environment, including a complete moratorium on drilling in the U.S. Gulf of Mexico. These factors could have a significantly greater impact on our financial condition, results of operations and cash flows than if our operations were more diversified. Because our fleet is mobile, we may have similar concentration risk in other geographic locations in the future.

If we are unable to make acquisitions from Transocean or third parties on economically acceptable terms, our future growth would be limited, and any acquisitions we may make may reduce, rather than increase, our cash flows and ability to make distributions to unitholders.

Our strategy to grow our business and increase distributions to unitholders is dependent in part on our ability to make acquisitions that result in an increase in cash available for distribution per unit. Our growth strategy is based in part on Transocean's obligation to offer us the opportunity to purchase four specified drilling rigs or other acquisitions that we expect to make from Transocean. There can be no assurance that such acquisitions will be available to us on an accretive basis, on acceptable terms or at all. Other than the obligation to offer us the opportunity to purchase these four drilling rigs, Transocean has no obligation to make any acquisitions available to us. The consummation and timing of any future acquisitions will depend upon, among other things, whether:

- we are able to identify attractive acquisition candidates;
- we are able to negotiate acceptable purchase agreements;
- we are able to obtain financing for these acquisitions on economically acceptable terms; and
- we are outbid by competitors.

We can offer no assurance that we will be able to successfully consummate any future acquisitions, whether from Transocean or any third parties. Any acquisitions that may be available to us may require that we access the debt and equity markets. However, we may be unable to access such markets on attractive terms or at all. If we are unable to make future acquisitions, our future growth and ability to increase distributions will be limited. Furthermore, even if we do consummate acquisitions that we believe will be accretive, they may in fact result in a decrease in cash available for distribution as a result of incorrect assumptions in our evaluation of such acquisitions or unforeseen consequences or other external events beyond our control. Acquisitions involve numerous risks, including difficulties in integrating acquired businesses, inefficiencies and unexpected costs and liabilities.

The continuing effects of the enhanced regulations enacted following the Macondo well incident, the Consent Decree and the EPA Agreement could materially and adversely affect our operations.

New governmental safety and environmental requirements applicable to both deepwater and shallow water operations have been adopted for drilling in the U.S. Gulf of Mexico following the Macondo well incident in the U.S. Gulf of Mexico in 2010. In order to obtain drilling permits, operators must submit applications that demonstrate compliance with the enhanced regulations, which require independent third-party inspections, certification of well design and well control equipment and emergency response plans in the event of a blowout, among other requirements. Operators have previously had, and may in the future have, difficulties obtaining drilling permits in the U.S. Gulf of Mexico. In addition, the oil and gas industry has adopted new equipment and operating standards, such as the American Petroleum Institute Standard 53 relating to the installation and testing of well control equipment. These new safety and environmental guidelines and standards and any further new guidelines or standards the U.S. government or industry may issue or any other steps the U.S. government or industry may take, could disrupt or delay operations, increase the cost of operations, increase out-of-service time or reduce the area of operations for drilling rigs in U.S. and non-U.S. offshore areas.

Other governments could take similar actions relating to implementing new safety and environmental regulations in the future. Additionally, some of our customers have elected or may elect to voluntarily comply with some or all of the new inspections, certification requirements and safety and environmental guidelines on rigs operating outside of the U.S. Gulf of Mexico. Additional governmental regulations and requirements concerning licensing, taxation, equipment specifications and training requirements or the voluntary adoption of such requirements or guidelines by our customers could increase the costs of our operations, increase certification and permitting requirements, increase review periods and impose increased liability on offshore operations.

Because we are an affiliate of Transocean, our operations in the waters of the U.S. are subject to the safety, environmental, reporting, operational and other requirements of the Consent Decree and the EPA Agreement. These requirements are in addition to the regulations applicable to all industry participants and may add additional costs and liabilities and may adversely affect our customers' perception of us and may place us at a competitive disadvantage to other offshore drillers.

Pursuant to the Consent Decree, Transocean agreed to take specified actions relating to operations in U.S. waters, including, among other things, the design and implementation of, and compliance with, additional systems and procedures; blowout preventer certification and reports; measures to strengthen well control competencies, drilling monitoring, recordkeeping, incident reporting, risk management and oil spill training, exercises and response planning; communication with operators; alarm systems; transparency and responsibility for matters relating to the Consent Decree; and technology innovation, with a first emphasis on more efficient, reliable blowout preventers. The Consent Decree provides for independent auditors for compliance with the Consent Decree and an independent process safety consultant and requires certain plans, reports and submissions be made and be acceptable to the U.S. and also requires certain publicly available filings.

In the EPA Agreement, Transocean agreed to, among other things, continue the implementation of certain programs and systems; comply with certain employment and contracting procedures; engage independent compliance auditors and a process safety consultant; and give reports and notices with respect to various matters.

The continuing effects of the enhanced regulations may also decrease the demand for drilling services, negatively affect dayrates and increase out-of-service time, which could ultimately have a material adverse effect on our revenue and profitability. We are unable to predict the full impact that the continuing effects of the enhanced regulations will have on our operations.

In addition, subject to certain exceptions, the EPA Agreement prohibits us from entering into, extending or engaging in certain business relationships with individuals or entities that are debarred, suspended, proposed for debarment or similarly restricted in the U.S. The loss of any of our customers due to such restrictions could, at least in the short term, have a material adverse effect on our financial condition, results of operations and cash flows.

Our growth and our business depend on the level of activity in oil and gas exploration, development and production in offshore areas.

Our growth and our business depend on the level of activity in oil and gas exploration, development and production in offshore areas. Demand for our services depends on oil and natural gas industry activity and expenditure levels that are directly affected by trends in oil and natural gas prices.

Oil and gas prices are extremely volatile and are affected by numerous factors, including the following:

- worldwide demand for oil and gas, including economic activity in the U.S. and other large energy-consuming markets;
- the ability of the Organization of the Petroleum Exporting Countries ("OPEC") to set and maintain production levels, productive spare capacity and pricing;
- the level of production in non-OPEC countries;
- the policies of various governments regarding exploration and development of their oil and gas reserves;
- advances in exploration, development and production technology;
- the discovery rate of new oil and gas reserves;
- the rate of decline of existing oil and gas reserves;
- laws and regulations related to environmental matters, including those addressing alternative energy sources and the risks of global climate change;
- the development and exploitation of alternative fuels;
- the development of new technology to exploit oil and gas reserves, such as shale oil;
- accidents, adverse weather conditions, natural disasters and other similar incidents relating to the oil and gas industry; and
- the worldwide security and political environment, including uncertainty or instability resulting from an escalation or outbreak of armed hostilities, civil unrest or other crises in the Middle East or Eastern Europe or other geographic areas or acts of terrorism.

Demand for our services is particularly sensitive to the level of exploration, development and production activity of, and the corresponding capital spending by, oil and natural gas companies, including national oil companies. Any prolonged reduction in oil and natural gas prices could depress the immediate levels of exploration, development and production activity. Perceptions of longer-term lower oil and natural gas prices by oil and gas companies could similarly reduce or defer major expenditures given the long-term nature of many large-scale development projects. Lower levels of activity result in a corresponding decline in the demand for our services, which could have a material adverse effect on our revenue and profitability. Oil and gas prices and market expectations of potential changes in these prices significantly affect this level of activity. However, higher near-term commodity prices do not necessarily translate into increased drilling activity since customers' expectations of longer-term future commodity prices typically drive demand for our rigs. Also, increased competition for customers' drilling budgets could come from, among other areas, offshore areas where we do not currently operate and land-based energy markets in Africa, Russia, China, the Middle East, the U.S. and elsewhere. The availability of quality drilling prospects, exploration success, relative production costs, the stage of reservoir development and political and regulatory environments also affect customers' drilling campaigns. Worldwide military, political and economic events have contributed to oil and gas price volatility and are likely to do so in the future.

Our current backlog of contract drilling revenue may not be fully realized, which may have a material adverse impact on our financial position, results of operations or cash flows, and will reduce cash available for distribution.

Our contract backlog represents the firm term of the drilling contract multiplied by the maximum contractual operating rate, which may be higher than the actual dayrate we receive or we may receive other dayrates included in the contract such as waiting-on-weather rate, repair rate, standby rate or force majeure rate. The contractual operating dayrate may also be higher than the actual dayrate we receive because of a number of factors, including rig downtime or suspension of operations.

Several factors could cause rig downtime or a suspension of operations, including:

- breakdowns of equipment and other unforeseen engineering problems;
- work stoppages, including labor strikes;
- shortages of material and skilled labor;
- surveys by government and maritime authorities;
- periodic classification surveys;
- severe weather, strong ocean currents or harsh operating conditions; and
- force majeure events.

In certain drilling contracts, the dayrate may be reduced to zero or result in customer credit against future dayrate if, for example, repairs extend beyond a stated period of time. Our contract backlog currently includes signed drilling contracts, although, in some cases, we may include contracts represented by other definitive agreements awaiting contract execution. We may be unable to realize the full amount of our contract backlog due to events beyond our control. Our customers could experience liquidity issues if commodity prices decline to lower levels for an extended period of time. Liquidity issues could lead our customers to go into bankruptcy or could encourage our customers to seek to repudiate, cancel or renegotiate these agreements for various reasons, as described under "Our drilling contracts may be terminated due to a number of events" below. Our inability to realize the full amount of our contract backlog may have a material adverse effect on our financial condition, results of operations or cash flows and could reduce our cash available for distribution.

Our drilling contracts may be terminated due to a number of events.

Drilling contracts with customers may be cancelable at the option of the customer upon payment of an early termination payment. Such payments may not, however, fully compensate us for the loss of the contract. Drilling contracts also customarily provide for either automatic termination or termination at the option of the customer typically without the payment of any termination fee, under various circumstances such as non-performance, as a result of significant downtime or impaired performance caused by equipment or operational issues, or sustained periods of downtime due to force majeure events. Many of these events are beyond our control. During periods of depressed market conditions, we are subject to an increased risk of our customers seeking to repudiate their contracts, including through claims of non-performance. Our customers' ability to perform their obligations under their drilling contracts, including their ability to fulfill their indemnity obligations to us, may also be negatively impacted by an economic downturn. Our customers often have significant bargaining leverage over us. If our customers cancel some of our contracts, and we are unable to secure new contracts on a timely basis and on substantially similar terms, or if contracts are suspended for an extended period of time or if a number of our contracts are renegotiated, it could adversely affect our financial condition, results of operations or cash flows and reduce our cash available for distribution. See "Item 1. Business—Drilling Contracts."

Our debt levels may limit our flexibility in obtaining additional financing and paying distributions to unitholders, and we may suffer competitive disadvantages.

At December 31, 2014, our consolidated debt was approximately $43 million. We have the ability to incur additional debt (see "Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources"). Our level of debt and other obligations could have significant adverse consequences for our business and future prospects, including the following:

- we may be unable to obtain financing on favorable terms or at all in the future for working capital, capital expenditures, acquisitions, debt service requirements, distributions or other purposes;
- we may not be able to use operating cash flow in other areas of our business or to make distributions because we must dedicate a substantial portion of these funds to service the debt;
- we could become more vulnerable to general adverse economic and industry conditions, including increases in interest rates, particularly if we have substantial indebtedness that bears interest at variable rates;
- we may not be able to meet financial ratios or satisfy certain other conditions included in our credit facilities, which could result in our inability to meet requirements for borrowings under our credit facilities or a default under our credit facilities and trigger cross default provisions in our other debt instruments; and
- we may be less able to take advantage of significant business opportunities and to react to changes in market or industry conditions than our less levered competitors.

We may require a significant amount of cash to service our indebtedness and other obligations. Our ability to generate cash depends on many factors beyond our control.

Our ability to make payments on, or refinance, our indebtedness and to fund our working capital needs and planned capital expenditures will depend on our ability to generate cash in the future. A significant reduction in our operating cash flows, including as a result of changes in general economic conditions, timing of contracts or payments, expiration or termination of drilling contracts, legislative or regulatory conditions, increased competition or other events beyond our control, could increase the need for additional or alternative sources of liquidity and could have a material adverse effect on our financial condition, results of operations, cash flows and ability to service our debt and other obligations.

If we are unable to service our indebtedness or to fund our liquidity needs, we may be forced to adopt an alternative strategy that may include actions such as reducing capital expenditures, reducing distributions, selling assets, restructuring or refinancing indebtedness, seeking additional capital or any combination of the foregoing. We cannot assure you that any of these alternative strategies could be affected on satisfactory terms, or at all, or that they would yield sufficient funds to enable us to make required payments on our indebtedness or to fund our other liquidity needs. Reducing or delaying capital expenditures or selling assets could delay future cash flows. In addition, the terms of existing or future debt agreements may restrict us from adopting any of these alternatives.

Our failure to generate sufficient operating cash flow or to achieve any of these alternatives could significantly adversely affect the value of our common units. In addition, if we default in the payment of amounts due on any indebtedness, such default would give rise to an event of default under the agreements governing our indebtedness and could lead to the possible acceleration of amounts due under any of our outstanding indebtedness. In the event of any acceleration, we may not have enough cash to repay our outstanding indebtedness.

Financing agreements, including Transocean's financing agreements, containing operating and financial restrictions and other covenants may restrict our business and financing activities.

The operating and financial restrictions and covenants in our financing agreements and those of Transocean and any future financing agreements of Transocean or us could adversely affect our ability to finance future operations or capital needs or to engage, expand or pursue our business activities. We will be required to comply with the terms of Transocean's agreements regarding indebtedness and have agreed to take no actions that would cause Transocean not to be in compliance with such agreements. For example, the indentures governing Transocean's outstanding senior notes may restrict our ability to create or permit liens on our assets. Transocean may incur liens solely for reasons relating to its business that does not affect or benefit us, and it will have no obligation to take into account the impact of the creation of such liens on us. As such, our ability to incur secured indebtedness will depend in part on Transocean's financial condition, capital needs and plans. In addition, subject to certain exceptions, the financing agreements may restrict our ability to:

- pay distributions to our unitholders;
- enter into other financing agreements;
- incur additional indebtedness;
- create or permit liens on our assets;
- sell our drilling rigs or the capital stock of our subsidiaries;
- change the nature of our business;
- make investments;
- change the management or ownership of our drilling rigs;
- make capital expenditures; and
- compete effectively to the extent our competitors are subject to less onerous restrictions.

Transocean may enter into agreements in the future with different or additional restrictions and covenants that will apply to us.

Our ability to comply with the restrictions and covenants, including financial ratios and tests, contained in any financing agreements of Transocean or us, is dependent on our or Transocean's future performance and may be affected by events beyond our control, including actions by Transocean and prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we are unable to comply with the restrictions and covenants in the agreements governing our indebtedness or in current or future debt financing agreements, there could be a default under the terms of those agreements. If a default occurs under these agreements, lenders could terminate their commitments to lend or accelerate the outstanding loans and declare all amounts borrowed due and payable. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Restrictions in our debt agreements may prevent us from paying distributions.

The payment of principal and interest on our debt will reduce our cash available for distribution. In addition, our financing agreements are expected to contain provisions that, upon the occurrence of certain events, permit lenders to terminate their commitments or accelerate the outstanding loans and declare all amounts due and payable, which may prevent us from paying distributions to our unitholders. These events may include, among others:

- a failure to pay any principal, interest, fees, expenses or other amounts when due;
- a violation of covenants requiring us to maintain certain financial ratios;
- a default under any other provision of the financing agreement, as well as a default under any provision of related security documents;
- a material breach of any representation or warranty contained in the applicable financing agreement;
- a default under other indebtedness;
- a failure to comply with a final legal judgment from a court of competent jurisdiction;
- a bankruptcy or insolvency event;
- a suspension or cessation of our business;
- the destruction or abandonment of our assets, or the seizure or appropriation thereof by any governmental, regulatory or other authority if the lenders determine such occurrence could have a material adverse effect on our business or our ability to satisfy our obligations under or otherwise comply with the applicable financing agreement;
- the invalidity, unlawfulness or repudiation of any financing agreement or related security document;
- an enforcement of any liens or other encumbrances covering our assets; and
- the occurrence of certain other events that are likely to have a material adverse effect on our business or our ability to satisfy our obligations under or otherwise comply with the applicable financing agreement.

See "Management's Discussion and Analysis of Financial Conditions and Results of Operations—Liquidity and Capital Resources—Revolving credit facilities."

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

The offshore contract drilling industry is highly competitive with numerous industry participants, none of which has a dominant market share. Drilling contracts are generally awarded on a competitive bid basis. Intense price competition is often the primary factor in determining which qualified contractor is awarded a job, although rig availability and the quality and technical capability of services and equipment are also considered.

The offshore contract drilling industry has historically been cyclical and is impacted by oil and gas price levels and volatility. There have been periods of high demand, short rig supply and high dayrates, followed by periods of low demand, excess rig supply and low dayrates. Changes in commodity prices can have a dramatic effect on rig demand, and periods of excess rig supply may intensify competition in the industry and result in rigs being idle for long periods of time. In addition, certain competitors have greater financial resources than we do, which may enable them to better withstand periods of low utilization and compete more effectively on the basis of price.

During prior periods of high dayrates and rig utilization rates, industry participants have increased the supply of rigs by ordering the construction of new units. This has historically resulted in an oversupply of rigs and has caused a subsequent decline in dayrates and rig utilization rates, sometimes for extended periods of time. Presently, there are numerous recently constructed high-specification floaters and other drilling units that are capable of competing with our rigs that have entered the global market, and there are more that are under contract for construction. The entry into service of these new units has increased and will continue to increase supply and has and could curtail a strengthening, or trigger a reduction, in dayrates as rigs are absorbed into the active fleet and lead to accelerated stacking of the existing fleet. A significant number of the newbuild units have not been contracted for work, which may intensify price competition. Any further increase in construction of new units would likely exacerbate the negative impact on dayrates and utilization rates. Lower dayrates and rig utilization rates could adversely affect our revenues, profitability and cash available for distribution.

We depend on affiliates of Transocean to assist us in operating and expanding our business.

Our ability to enter into new drilling contracts and expand our customer and supplier relationships will depend largely on our ability to leverage our relationship with Transocean and its reputation and relationships in the offshore drilling industry. If Transocean suffers material damage to its reputation, relationships or financial condition, it could adversely affect us and limit the benefits we expect to derive from our present and future relationship with Transocean. Among other things, such damage may adversely affect Transocean's ability to provide services to us and to enter into newbuild, acquisition or sale transactions that may benefit us and may harm our business and prospects, including our ability to:

- renew existing drilling contracts upon their expiration;
- obtain new drilling contracts;
- efficiently and productively carry out our business activities;
- acquire additional assets from Transocean;
- successfully interact with shipyards;
- obtain financing and maintain insurance on commercially acceptable terms;
- maintain satisfactory relationships with suppliers, labor and other third parties; or
- enforce our contractual rights against Transocean, including indemnification rights.

Such damage and other adverse effects could arise from events beyond our control, including developments relating to the Macondo well incident. In addition, pursuant to the master services agreements and the support and secondment agreements, affiliates of Transocean will provide us with significant operational, administrative, financial and other support services or personnel. Our operational success and ability to execute our growth strategy will depend significantly upon the satisfactory performance of these services.

See "Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 11—Related Party Transactions."

Our shipyard projects and operations are subject to delays and cost overruns.

Our rigs will undergo shipyard projects from time to time. These shipyard projects are subject to the risks of delay or cost overruns inherent in any such construction project resulting from numerous factors, including the following:

- shipyard availability, failures and difficulties;
- shortages of equipment, materials or skilled labor;
- unscheduled delays in the delivery of ordered materials and equipment;
- design and engineering problems, including those relating to the commissioning of newly designed equipment;
- latent damages or deterioration to hull, equipment and machinery in excess of engineering estimates and assumptions;
- unanticipated actual or purported change orders;
- disputes with shipyards and suppliers;
- failure or delay of third-party vendors or service providers;
- availability of suppliers to recertify equipment for enhanced regulations;
- strikes, labor disputes and work stoppages;
- customer acceptance delays;
- adverse weather conditions, including damage caused by such conditions;
- terrorist acts, war, piracy and civil unrest;
- unanticipated cost increases; and
- difficulty in obtaining necessary permits or approvals.

These factors may contribute to cost variations and delays in the delivery of our rigs undergoing shipyard projects. Delays in the delivery of these units would result in delay in contract commencement, resulting in a loss of revenue to us, and may also cause customers to terminate or shorten the term of the drilling contract for the rig pursuant to applicable late delivery clauses. In the event of termination of any of these drilling contracts, we may not be able to secure a replacement contract on as favorable terms, if at all.

Our operations also rely on a significant supply of capital and consumable spare parts and equipment to maintain and repair our fleet. We also rely on the supply of ancillary services, including supply boats and helicopters. Shortages in materials, manufacturing defects, delays in the delivery of necessary spare parts, equipment or other materials, or the unavailability of ancillary services could negatively impact our future operations and result in increases in rig downtime and delays in the repair and maintenance of our fleet.

Our business involves numerous operating hazards, and our insurance and indemnities from our customers may not be adequate to cover potential losses from our operations.

Our operations are subject to the usual hazards inherent in the drilling of oil and gas wells, such as blowouts, reservoir damage, loss of production, loss of well control, lost or stuck drill strings, equipment defects, craterings, fires, explosions and pollution. Contract drilling requires the use of heavy equipment and exposure to hazardous conditions, which may subject us to liability claims by employees, customers and other parties. These hazards can cause personal injury or loss of life, severe damage to or destruction of property and equipment, pollution or environmental damage, claims by third parties or customers and suspension of operations. Our offshore fleet is also subject to hazards inherent in marine operations, either while on site or during mobilization, such as capsizing, sinking, grounding, collision, piracy, damage from severe weather and marine life infestations. The U.S. Gulf of Mexico area is subject to hurricanes or other extreme weather conditions on a relatively frequent basis, and our drilling rigs in this region may be exposed to damage or total loss by these storms, some of which may not be covered by insurance. The occurrence of these events could result in the suspension of drilling operations, damage to or destruction of the equipment involved and injury to or death of rig personnel. Some experts believe global climate change could increase the frequency and severity of these extreme weather conditions. Operations may also be suspended because of machinery breakdowns, abnormal drilling conditions, failure of subcontractors to perform or supply goods or services or personnel shortages. We customarily provide contract indemnity to our customers for certain claims that could be asserted by us relating to damage to or loss of our equipment, including rigs, and claims that could be asserted by us or our employees relating to personal injury or loss of life.

Damage to the environment could also result from our operations, particularly through spillage of hydrocarbons, fuel, lubricants or other chemicals and substances used in drilling operations, or extensive uncontrolled fires. We may also be subject to property damage, environmental indemnity and other claims by oil and natural gas companies. Drilling involves certain risks associated with the loss of control of a well, such as blowout, cratering, the cost to regain control of or re-drill the well and remediation of associated pollution. Our customers may be unable or unwilling to indemnify us against such risks. In addition, a court may decide that certain indemnities in our current or future drilling contracts are not enforceable. The law generally considers contractual indemnity for criminal fines and penalties to be against public policy, and the enforceability of an indemnity as to other matters may be limited.

Our insurance policies and drilling contracts contain rights to indemnity that may not adequately cover our losses, and we do not have insurance coverage or rights to indemnity for all risks. We participate in Transocean's insurance program and have two main types of coverage: (1) hull and machinery coverage for physical damage to our property and equipment and (2) excess liability coverage which generally covers offshore risks, such as personal injury, third-party property claims and third-party non-crew claims, including wreck removal and pollution. We will not generally carry commercial market insurance coverage for loss of revenues unless we are contractually required or for losses resulting from physical damage to our fleet caused by named windstorms in the U.S. Gulf of Mexico, including liability for wreck removal costs.

If a significant accident or other event occurs that is not fully covered by our insurance or an enforceable or recoverable indemnity from any agreement, the occurrence could adversely affect our consolidated statement of financial position, results of operations or cash flows. The amount of our insurance may also be less than the related impact on enterprise value after a loss. Our insurance coverage will not in all situations provide sufficient funds to protect us from all liabilities that could result from our drilling operations. Our coverage includes annual aggregate policy limits. As a result, we generally retain the risk for any losses in excess of these limits. We generally do not carry insurance for loss of revenue unless contractually required, and certain other claims may also not be reimbursed by insurance carriers. Any such lack of reimbursement may cause us to incur substantial costs. In addition, we could decide to retain more risk in the future, resulting in higher risk of losses, which could be material. Moreover, we may not be able to maintain adequate insurance in the future at rates that we consider reasonable or be able to obtain insurance against certain risks.

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

Our reliance on third-party suppliers, manufacturers and service providers to secure equipment, parts, components and sub-systems used in our operations exposes us to volatility in the quality, prices and availability of such items. Certain parts and equipment that we use in our operations may be available only from a small number of suppliers, manufacturers or service providers, or in some cases must be sourced through a single supplier, manufacturer or service provider. Recent industry developments have reduced the number of available suppliers. A disruption in the deliveries from such third-party suppliers, manufacturers or service providers, capacity constraints, production disruptions, price increases, quality control issues, recalls or other decreased availability of parts and equipment could adversely affect our ability to meet our commitments to customers, adversely impact our operations and revenues or increase our operating costs.

Our operating and maintenance costs will not necessarily fluctuate in proportion to changes in operating revenues.

Our operating and maintenance costs will not necessarily fluctuate in proportion to changes in operating revenues. Costs for operating a rig are generally fixed or only semi-variable regardless of the dayrate being earned. In addition, should our rigs incur unplanned downtime while on contract or idle time between drilling contracts, we typically will not reduce the staff on those rigs because we will use the crew to prepare the rig for its next contract. During times of reduced activity, reductions in costs may not be immediate as portions of the crew may be required to prepare rigs for stacking, after which time the crew members are assigned to active rigs or dismissed. In general, labor costs increase primarily due to higher salary levels and inflation. Equipment maintenance expenses fluctuate depending upon the type of activity the unit is performing and the age and condition of the equipment, and these expenses could increase for short or extended periods as a result of regulatory or customer requirements that raise maintenance standards above historical levels. Contract preparation costs vary based on the scope and length of contract preparation required and the duration of the firm contractual period over which such expenditures are amortized.

Our drilling contracts may not permit us to fully recoup our cost increases in the event of an increase in expenses.

Our drilling contracts have dayrates that are fixed over the contract term. In order to mitigate the effects of inflation on revenues from these term contracts, our drilling contracts include cost escalation and de-escalation provisions. These provisions allow or require us to adjust the dayrates based on certain published indices and our historical costs. These provisions are designed to adjust commensurately with certain changes to our costs, including wages, insurance and maintenance costs. However, actual cost increases may result from events or conditions that do not cause correlative changes to the applicable indices. Furthermore, certain indices may be outdated at the time of adjustment. In addition, the adjustments are normally performed only periodically. For these reasons, the timing and amount received as a result of the adjustments may differ from the timing and amount of expenditures associated with actual cost increases or decreases, which could adversely affect our cash flow and ability to make cash distributions. In addition, certain of our future drilling contracts may not include such provisions, which would further expose our results of operations to the effects of inflation on our expenses.

Failure to recruit and retain key personnel could hurt our operations.

We depend on the continuing efforts of highly skilled personnel to operate and provide technical services and support for our business. Historically, competition for the personnel required for drilling operations has intensified as the number of rigs activated, added to fleets or under construction increased, leading to shortages of qualified personnel in the industry and creating upward pressure on wages and higher turnover. Our personnel are employed by Transocean and seconded to us. We may experience a reduction in the experience level of the personnel involved in our operations as a result of any increased turnover, which could lead to higher downtime and more operating incidents, which in turn could decrease revenues and increase costs. If increased competition for qualified personnel were to intensify in the future, we may experience increases in costs or limits on operations.

Our labor costs and the operating restrictions under which we operate could increase as a result of collective bargaining negotiations and changes in labor laws and regulations.

Legislation has been introduced in the U.S. Congress that could encourage unionization efforts in the U.S., as well as increase the chances that such efforts succeed. Unionization efforts, if successful, new collective bargaining agreements or work stoppages could materially increase our labor costs and operating restrictions.

Any operations outside the U.S. may involve additional risks.

Although all of our operations are currently in the U.S. Gulf of Mexico, our drilling units are capable of operating in various regions throughout the world, which may expose us to additional political and other uncertainties, including risks of:

- terrorist acts, war, piracy and civil unrest;
- seizure, expropriation or nationalization of our equipment;
- expropriation or nationalization of our customers' property;
- repudiation or nationalization of contracts;
- imposition of trade or immigration barriers;
- Import-export quotas;
- wage and price controls;
- changes in law and regulatory requirements, including changes in interpretation and enforcement;
- involvement in judicial proceedings in unfavorable jurisdictions;
- damage to our equipment or violence directed at our employees, including kidnappings;
- complications associated with supplying, repairing and replacing equipment in remote locations;
- the inability to move income or capital; and
- currency exchange fluctuations.

Non-U.S. contract drilling operations are subject to various laws and regulations in certain countries in which we may operate, including laws and regulations relating to the import and export, equipment and operation of drilling units, currency conversions and repatriation, oil and gas exploration and development, and taxation of offshore earnings and earnings of expatriate personnel. Any non-U.S. operations also will be subject to the U.S. Treasury Department's Office of Foreign Assets Control ("OFAC") and other U.S. laws and regulations governing our international operations. In addition, various state and municipal governments, universities and other investors, including, with respect to state governments, by state retirement systems, have proposed or adopted divestment and other initiatives regarding investments in companies that do business with countries that have been designated as state sponsors of terrorism by the U.S. State Department. Failure to comply with applicable laws and regulations, including those relating to sanctions and export restrictions, may subject us to criminal sanctions or civil remedies, including fines, denial of export privileges, injunctions or seizures of assets. Investors could view any potential violations of OFAC regulations negatively, which could adversely affect our reputation and the market for our common units.

Governments in some foreign countries have become increasingly active in regulating and controlling the ownership of concessions and companies holding concessions, the exploration for oil and gas and other aspects of the oil and gas industries in their countries, including local content requirements for participating in tenders for certain drilling contracts. Many governments favor or effectively require the awarding of drilling contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction or require use of a local agent or interest owner. In addition, government action, including initiatives by OPEC, may continue to cause oil or gas price volatility. In some areas of the world, this governmental activity has adversely affected the amount of exploration and development work by oil companies and may continue to do so.

The shipment of goods, services and technology across international borders subjects us to extensive trade laws and regulations. Our import and export activities are governed by unique customs laws and regulations in each of the countries where we operate. Moreover, many countries, including the U.S., control the import and export of certain goods, services and technology and impose related import and export recordkeeping and reporting obligations. Governments also may impose economic sanctions against certain countries, persons and other entities that may restrict or prohibit transactions involving such countries, persons and entities, and we are also subject to the U.S. anti-boycott law.

The laws and regulations concerning import and export activity, recordkeeping and reporting, import and export control and economic sanctions are complex and constantly changing. These laws and regulations may be enacted, amended, enforced or interpreted in a manner materially impacting our operations. Ongoing economic challenges may increase some foreign governments' efforts to enact, enforce, amend or interpret laws and regulations as a method to increase revenue. Shipments can be delayed and denied import or export for a variety of reasons, some of which are outside our control and some of which may result from failure to comply with existing legal and regulatory regimes. Shipping delays or denials could cause unscheduled operational downtime.

Our ability to operate worldwide will depend on our ability to obtain the necessary visas and work permits for our personnel to travel in and out of, and to work in, the jurisdictions in which we plan to operate. Governmental actions in some of the jurisdictions in which we plan to operate may make it difficult for us to move our personnel in and out of these jurisdictions by delaying or withholding the approval of these permits. If we are not able to obtain visas and work permits in the future for the employees we will need to operate our rigs on a timely basis, we might not be able to perform our obligations under future drilling contracts, which could allow our customers to cancel such contracts. If our customers cancel future drilling contracts, and we are unable to secure replacement drilling contracts on a timely basis and on substantially similar terms, it may adversely affect our financial condition, results of operations or cash flows.

If any of our drilling rigs fails to maintain its class certification or fails any required survey, that drilling rig would be unable to operate, thereby reducing our revenues and profitability.

Every offshore drilling rig is a registered marine vessel and must be "classed" by a classification society. The classification society certifies that the drilling rig is "in-class," signifying that such drilling rig has been built and maintained in accordance with the rules of the classification society and complies with applicable rules and regulations of the drilling rig's country of registry and the international conventions of which that country is a member. In addition, where surveys are required by international conventions and corresponding laws and ordinances of a flag state, the classification society will undertake such surveys on application or by official order, acting on behalf of the authorities concerned. If any drilling rig does not maintain its class or fails any annual survey or special survey, the drilling rig will be unable to carry on operations and will be unemployable and uninsurable, which could cause us to be in violation of certain covenants in our credit facility. Any such inability to carry on operations or be employed could have a material adverse impact on our financial condition, results of operations or our ability to make distributions to our unitholders.

We have significant carrying amounts of long-lived assets and goodwill, which are subject to impairment testing, and we could be required to recognize losses on impairment of our long-lived assets or goodwill.

At December 31, 2014, the carrying amount of our property and equipment was $2.0 billion, representing 75 percent of our total assets, and the carrying amount of our goodwill was $356 million, representing 14 percent of our total assets. In accordance with our critical accounting policies, we review our property and equipment for impairment when events or changes in circumstances indicate that the aggregate carrying amount of our assets held and used may not be recoverable, and we review our goodwill for impairment annually and when events occur or circumstances change that would more likely than not reduce the fair value of our reporting unit below its carrying amount. During the three months ended December 31, 2014, we observed a rapid and significant decline in the market value of our stock, the market value of Transocean's stock, prices of oil and natural gas and the actual and projected declines in dayrates and utilization. We considered these indicators that the fair value of our goodwill could have fallen below its carrying amount, and as a result, we performed an interim goodwill impairment test. Although we determined that our goodwill was not impaired as of December 31, 2014, we concluded that our reporting unit was at risk of failing the first step of our goodwill impairment test, as the reporting unit's estimated fair value exceeded its carrying amount by less than 5 percent. Future expectations of lower dayrates or rig utilization rates or changes in market conditions could lead us to believe that the aggregate carrying amount of the drilling units in our asset group is unrecoverable or that the fair value of our reporting unit has fallen below its carrying amount. If we determine that either of these situations has occurred, we could be required to recognize losses on impairment of our long-lived asset group or our goodwill, which could adversely affect our consolidated statement of financial position and results of operations.

Increases in interest rates could adversely impact the price of our common units, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

Interest rates on future borrowings under credit facilities and on debt offerings could be higher than current levels causing our financing costs to increase accordingly. As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on the price of our common units, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

Compliance with or breach of environmental laws can be costly, expose us to liability and could limit our operations.

Our business in the offshore drilling industry is affected by laws and regulations relating to the energy industry and the environment, including international conventions and treaties, and regional, national, state and local laws and regulations. The offshore drilling industry depends on demand for services from the oil and gas exploration and production industry, and, accordingly, we are directly affected by the adoption of laws and regulations that, for economic, environmental or other policy reasons, curtail exploration and development drilling for oil and gas. Compliance with such laws, regulations and standards, where applicable, may require us to make significant capital expenditures, such as the installation of costly equipment or operational changes, and may affect the resale values or useful lives of our rigs. We may also incur additional costs in order to comply with other existing and future regulatory obligations, including, but not limited to, costs relating to air emissions, including greenhouse gases, the management of ballast waters, maintenance and inspection, development and implementation of emergency procedures and insurance coverage or other financial assurance of our ability to address pollution incidents.

Offshore drilling in certain areas has been curtailed and, in certain cases, prohibited because of concerns over protection of the environment. These costs could have a material adverse effect on our financial condition, results of operations or cash flows. A failure to comply with applicable laws and regulations may result in administrative and civil penalties, criminal sanctions or the suspension or termination of our operations.

To the extent new laws are enacted or other governmental actions are taken that prohibit or restrict offshore drilling or impose additional environmental protection requirements that result in increased costs to the oil and gas industry, in general, or the offshore drilling industry, in particular, our business or prospects could be materially adversely affected. The operation of our drilling rigs will require certain governmental approvals. These governmental approvals may involve public hearings and costly undertakings on our part. We may not obtain such approvals or such approvals may not be obtained in a timely manner. If we fail to timely secure the necessary approvals or permits, our customers may have the right to terminate or seek to renegotiate their drilling contracts to our detriment. The amendment or modification of existing laws and regulations or the adoption of new laws and regulations curtailing or further regulating exploratory or development drilling and production of oil and gas could have a material adverse effect on our business, consolidated statement of financial position or results of operations. Compliance with any such new legislation or regulations could have an adverse effect on our statements of operations and cash flows.

As an operator of mobile offshore drilling units in some offshore areas, we may be liable for damages and costs incurred in connection with oil spills or waste disposals related to those operations, and we may also be subject to significant fines in connection with spills. For example, an oil spill could result in significant liability, including fines, penalties and criminal liability and remediation costs for natural resource damages, as well as third-party damages, to the extent that the contractual indemnification provisions in our drilling contracts are not enforceable or are otherwise insufficient, or if our customers are unwilling or unable to contractually indemnify us from these risks. Additionally, we may not be able to obtain such indemnities in our future drilling contracts, and our customers may not have the financial capability to fulfill their contractual obligations to us. Also, these indemnities may be held to be unenforceable in certain jurisdictions, as a result of public policy considerations or for other reasons. Laws and regulations protecting the environment have become more stringent in recent years, and may in some cases impose strict liability, rendering a person liable for environmental damage without regard to negligence. These laws and regulations may expose us to liability for the conduct of or conditions caused by others or for acts that were in compliance with all applicable laws at the time they were performed. The application of these requirements or the adoption of new requirements or measures could have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. In addition, the Consent Decree and the EPA Agreement add to these regulations, requirements and liabilities.

Worldwide financial and economic conditions could have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

A slowdown in economic activity could reduce worldwide demand for energy and result in an extended period of lower oil and natural gas prices. A decline in oil and natural gas prices could reduce demand for our drilling services and have a material adverse effect on our statement of financial position, results of operations or cash flows. Worldwide financial and economic conditions could also cause our ability to access the capital markets to be severely restricted at a time when we would like, or need, to access such markets, which could have an impact on our flexibility to react to changing economic and business conditions. Worldwide economic conditions have in the past impacted, and could in the future impact, the lenders participating in our credit facilities and our customers, causing them to fail to meet their obligations to us.

Failure to comply with the U.S. Foreign Corrupt Practices Act and the U.K. Bribery Act 2010 could result in fines, criminal penalties, drilling contract terminations and an adverse effect on our business.

The U.S. Foreign Corrupt Practices Act ("FCPA") the U.K. Bribery Act 2010 ("Bribery Act") and similar anti-bribery laws in other jurisdictions generally prohibit companies and their intermediaries from making improper payments for the purpose of obtaining or retaining business. We may operate in many parts of the world that have experienced corruption to some degree and, in certain circumstances, strict compliance with anti-bribery laws may conflict with local customs and practices. If we are found to be liable for violations under the FCPA, the Bribery Act or other similar laws, either due to our acts or omissions or due to the acts or omissions of others, we could suffer from civil and criminal penalties or other sanctions, which could have a material adverse effect on our business, financial condition and results of operations.

Civil penalties under the anti-bribery provisions of the FCPA could range up to $10,000 per violation, with a criminal fine up to the greater of $2 million per violation or twice the gross pecuniary gain to us or twice the gross pecuniary loss to others, if larger. Civil penalties under the accounting provisions of the FCPA can range up to $500,000 per violation and a company that knowingly commits a violation can be fined up to $25 million per violation. In addition, both the SEC and the DOJ could assert that conduct extending over a period of time may constitute multiple violations for purposes of assessing the penalty amounts. Often, dispositions for these types of matters result in modifications to business practices and compliance programs and possibly the appointment of a monitor to review future business and practices with the goal of ensuring compliance with the FCPA.

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

Some scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases ("GHGs") and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere and other climatic changes. In response to such studies, the issue of climate change and the effect of GHG emissions, in particular emissions from fossil fuels, is attracting increasing attention worldwide.

Legislation to regulate emissions of GHGs has been introduced in the U.S. Congress. Some of the proposals would require industries to meet stringent new standards that may require substantial reductions in carbon emissions. Such reductions could be costly and difficult to implement. 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.

In the U.S., the EPA has undertaken efforts to regulate GHG emissions and has finalized motor vehicle GHG emissions standards, the effect of which could reduce demand for motor fuels refined from crude oil, and has also issued a final rule to address permitting of GHG emissions from stationary sources under the Clean Air Act's Prevention of Significant Deterioration and Title V programs commencing when the motor vehicle standards took effect on January 2, 2011. To the extent that our operations are subject to the EPA's GHG regulations, we may face increased capital and operating costs.

Because our business depends on the level of activity in the offshore oil and gas industry, existing or future laws, regulations, treaties or international agreements related to GHGs and climate change, including incentives to conserve energy or use alternative energy sources, could have a negative impact on our business if such laws, regulations, treaties or international agreements reduce the worldwide demand for oil and gas or limit drilling opportunities. In addition, such laws, regulations, treaties or international agreements could result in increased compliance costs or additional operating restrictions, which may have a negative impact on our business.

We may be subject to litigation that, if not resolved in our favor and not sufficiently insured against, could have a material adverse effect on us.

We may in the future be, from time to time, involved in various litigation matters. These matters may include, among other things, contract disputes, personal injury claims, environmental claims or proceedings, asbestos and other toxic tort claims, employment matters, governmental claims for taxes or duties and other litigation that arises in the ordinary course of our business. We cannot predict with certainty the outcome or effect of any claim or other litigation matter, and the ultimate outcome of any litigation or the potential costs to resolve them may have a material adverse effect on us. Insurance may not be applicable or sufficient in all cases, insurers may not remain solvent and policies may not be located. To the extent that one or more pending or future litigation matters is not resolved in our favor and is not covered by insurance, a material adverse effect on our financial results and condition could result.

Public health threats could have a material adverse effect on our operations and our financial results.

Public health threats, such as Severe Acute Respiratory Syndrome, severe influenza and other highly communicable viruses or diseases, outbreaks of which have already occurred in various parts of the world could adversely impact our operations. Any quarantine of personnel or inability to access our offices or rigs could adversely affect our operations. Travel restrictions or operational problems, or any reduction in the demand for drilling services caused by public health threats in the future, may materially impact operations and adversely affect our financial results.

Our information technology systems are subject to cybersecurity risks and threats.

We depend on digital technologies to conduct our offshore and onshore operations, to collect payments from customers and to pay vendors and employees. Threats to our information technology systems associated with cybersecurity risks and cyber incidents or attacks continue to grow. In addition, breaches to our systems could go unnoticed for some period of time. Risks associated with these threats include disruptions of certain systems on our rigs; other impairments of our ability to conduct our operations; loss of intellectual property, proprietary information or customer data; disruption of our customers' operations; loss or damage to our customer data delivery systems; and increased costs to prevent, respond to or mitigate cybersecurity events. If such a cyber-incident were to occur, it could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Under the master services agreements and certain other agreements, we are required to indemnify Transocean for any damages it may incur, and, except to the extent caused by Transocean's gross negligence, willful misconduct or fraud, Transocean is not required to indemnify us for any damages we may incur, in connection with its performance of services for us.

Pursuant to the master services agreements and certain other agreements, Transocean or its affiliates will provide certain administrative, technical and management services to us and the RigCos. In connection therewith, we are required to indemnify Transocean for any damages it may incur. Transocean, however, is not required to indemnify us for any damages we may incur in connection with its performance of these services except to the extent caused by Transocean's gross negligence, willful misconduct or fraud and except for damages arising from services rendered by Transocean in connection with certain drilling contracts with indemnity provisions that do not conform to Transocean's contracting principles, for which Transocean will not indemnify us, regardless of cause. In addition, Transocean's aggregate liability for such gross negligence or willful misconduct is limited to 10 times the annual services fees it receives under the applicable agreement. Our business will be harmed if Transocean and its affiliates fail to perform these services satisfactorily, if they cancel their agreements with us or if they stop providing these services to us.

See "Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 11—Related Party Transactions."

Acts of terrorism, piracy and political and social unrest could affect the markets for drilling services, which may have a material adverse effect on our results of operations.

Acts of terrorism and social unrest, brought about by world political events or otherwise, have caused instability in the world's financial and insurance markets in the past and may occur in the future. Such acts could be directed against companies such as ours. In addition, acts of terrorism, piracy and social unrest could lead to increased volatility in prices for crude oil and natural gas and could affect the markets for drilling services. Insurance premiums could increase and coverage may be unavailable in the future. U.S. government regulations may effectively preclude us from actively engaging in business activities in certain countries. These regulations could be amended to cover countries where we may wish to operate in the future.

Our drilling contracts do not generally provide indemnification against loss of capital assets or loss revenues resulting from acts of terrorism, piracy or social unrest. We have limited insurance for our assets providing coverage for physical damage losses resulting from risks, such as terrorist acts, piracy, vandalism, sabotage, civil unrest, expropriation and acts of war and we do not carry insurance for loss of revenues resulting from such risks.

Risks inherent in an investment in us

Transocean and its affiliates may compete with us, and we are limited in our ability to compete with Transocean.

Pursuant to the Omnibus Agreement that we and Transocean entered into in connection with the formation transactions, Transocean and its controlled affiliates, other than us, our subsidiaries and any publicly held affiliates of Transocean, agreed not to acquire, own, operate or contract for certain drilling rigs operating under drilling contracts of five or more years, subject to certain exceptions, without offering us the opportunity to purchase such rig. In addition, we agreed not to acquire, own, operate or contract for certain drilling rigs operating under drilling contracts of less than five years, subject to certain exceptions, without first offering the contract to Transocean. Relatively few drilling contracts have a term of five years or greater, particularly in the case of contracts that are not associated with newbuild units. As a result, we expect that Transocean will effectively have a right of first refusal on most drilling contract opportunities. Additionally, the Omnibus Agreement contains significant exceptions that may allow Transocean, any new publicly traded entity that Transocean may form or any of its controlled affiliates to compete with us, which could harm our business. Furthermore, we granted to Transocean a right of first offer on any proposed sale of any of our drilling rigs. Transocean has not granted us any such reciprocal right. As a result of these provisions, we are unable to pursue many new business opportunities without Transocean's consent. See "Part II. Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements—Note 11—Related Party Transactions."

Although we control the RigCos, the directors and officers of those companies owe duties to the RigCos and their other owner, Transocean, which may conflict with the interests of us and our unitholders.

Conflicts of interest may arise as a result of the relationships between us and our unitholders, on the one hand, and the RigCos, and their other owner, Transocean, on the other hand. Transocean currently owns a 49 percent noncontrolling interest in each of the RigCos and a 100 percent ownership interest in the Transocean Member. Our directors have duties to influence, in our role as controlling owner, the decisions made by the RigCos in a manner beneficial to us. At the same time, the directors and officers of the RigCos have a duty to act for the RigCos in a manner beneficial to all of the RigCos' owners, including Transocean. While we have influence in our role as controlling owner of the RigCos, the directors and officers of the RigCos exercise decisions of the RigCos and they have a duty to act in the best interests of the RigCos. Our board of directors may resolve conflicts of interest between Transocean and us and, to the extent acting in our role as the controlling owner of the RigCos, has broad latitude to consider the interests of all parties to the conflict. The resolution of these conflicts may not always be in the best interest of us or our unitholders.

For example, conflicts of interest may arise in the following situations:

- the allocation of shared overhead expenses to the RigCos and us;
- the interpretation and enforcement of contractual obligations between us and our affiliates, other than the RigCos, on the one hand, and the RigCos, on the other hand;
- the determination and timing of the amount of cash to be distributed to the RigCos' owners and the amount of cash to be reserved for the future conduct of the RigCos' business;
- the decision as to whether the RigCos should make asset or business acquisitions or dispositions, and on what terms;
- the determination of the amount and timing of the RigCos' capital expenditures;
- the determination of whether the RigCos should use cash on hand, borrow or issue equity to raise cash to finance maintenance or expansion capital projects, repay indebtedness, meet working capital needs or otherwise; and
- any decision we make to engage in business activities independent of, or in competition with, the RigCos.

Unitholders have limited voting rights.

Unlike the holders of common stock in a corporation, holders of common units have only limited voting rights on matters affecting our business. We will hold annual meetings of the members to elect one or more members of our board of directors and to vote on any other matters that are properly brought before the meeting. Common unitholders will be entitled to elect only four of the seven members of our board of directors. The Transocean Member in its sole discretion appoints the remaining three directors and sets the terms for which those directors will serve. Initially, all four of our elected directors will be elected at our annual meeting and will serve one-year terms. However, upon the election by the Transocean Member to classify our board of directors, the elected directors will be elected on a staggered basis and will serve for three-year terms. Our limited liability company agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management. Unitholders have no right to elect the Transocean Member, and the Transocean Member may not be removed except by a vote of the holders of at least 66 2/3 percent of the outstanding common and subordinated units, including any units owned by the Transocean Member and its affiliates, voting together as a single class. Any removal of the Transocean Member is subject to the approval of a successor Transocean Member by a unit majority.

The Transocean Member and its other affiliates own a controlling interest in us and have conflicts of interest and limited duties to us and our common unitholders, and the Transocean Member and its other affiliates may favor their own interests to the detriment of us and our other common unitholders.

Transocean owns the Transocean Member interest and a 70.8 percent limited liability company interest in us. Transocean also owns and controls the Transocean Member. All of our officers and certain of our directors are officers or directors of Transocean and its affiliates and, as such, they have fiduciary duties to Transocean that may cause them to pursue business strategies that disproportionately benefit Transocean or which otherwise are not in the best interests of us or our unitholders. Conflicts of interest may arise between Transocean and its affiliates on the one hand, and us and our unitholders on the other hand. As a result of these conflicts, Transocean and its affiliates may favor their own interests over the interests of our unitholders. See "—Our limited liability company agreement limits the duties that the Transocean Member and our directors and officers may have to our unitholders and restricts the remedies available to unitholders for actions taken by the Transocean Member or our directors and officers."

In addition to conflicts described elsewhere, these conflicts include, among others, the following situations:

- neither our limited liability company agreement nor any other agreement requires the Transocean Member or Transocean or its affiliates to pursue a business strategy that favors us or utilizes our assets, and Transocean's officers and directors have a fiduciary duty to make decisions in the best interests of the shareholders of Transocean, which may be contrary to our interests;
- our limited liability company agreement provides that the Transocean Member may make determinations or take or decline to take actions without regard to our or our unitholders' interests. Specifically, the Transocean Member may exercise its call right, preemptive rights or registration rights, consent or withhold consent to any merger or consolidation of the company, appoint any appointed directors or vote for the election of any elected director, vote or refrain from voting on amendments to our limited liability company agreement that require a vote of the outstanding units, voluntarily withdraw from the company, transfer, to the extent permitted under our limited liability company agreement, or refrain from transferring its units, the Transocean Member interest or incentive distribution rights or vote upon the dissolution of the company;
- the Transocean Member and our directors and officers have restricted their liabilities and duties they may have under the laws of the Marshall Islands, while also restricting the remedies available to our unitholders, and, as a result of purchasing common units, unitholders are treated as having agreed to the modified duties and to certain actions that may be taken by the Transocean Member and our directors and officers, all as set forth in our limited liability company agreement;
- the Transocean Member is entitled to reimbursement of all costs incurred by it and its affiliates for our benefit;
- our limited liability company agreement does not restrict us from paying the Transocean Member or its affiliates for any services rendered to us on terms that are fair and reasonable or entering into additional contractual arrangements with any of these entities on our behalf;
- the Transocean Member may exercise its right to call and purchase our common units if it and its affiliates own more than 80 percent of our common units; and
- the Transocean Member is not obligated to obtain a fairness opinion, nor will the unitholders be entitled to dissenter's rights of appraisal, regarding the value of the common units to be repurchased by it upon the exercise of its limited call right.

Although a majority of our directors will be elected by common unitholders, the Transocean Member will likely have substantial influence on decisions made by our board of directors due to its ability to appoint certain of our directors and its significant ownership of our common units. Transocean owns 21.3 million of our common units, representing 51.4 percent of our common units. Common unitholders that own 50 percent or more of our common units have the ability to request that cumulative voting be in effect for the election of elected directors. Therefore, for so long as Transocean owns 50 percent or more of our common units, it will have the ability to request that cumulative voting be in effect for the election of elected directors, which would generally enable Transocean to elect one or more of the elected directors even after it owns less than 50 percent of our common units.

Our officers face conflicts in the allocation of their time to our business.

Some of our officers are not required to work full-time on our affairs and also perform services for Transocean. As a result, there could be material competition for the time and effort of our officers who also provide services to other companies, which could have a material adverse effect on our business, results of operations and financial condition.

Our limited liability company agreement limits the duties that the Transocean Member and our directors and officers may have to our unitholders and restricts the remedies available to unitholders for actions taken by the Transocean Member or our directors and officers.

Our limited liability company agreement provides that our board of directors will have the authority to oversee and direct our operations, management and policies on an exclusive basis. The Marshall Islands Limited Liability Company Act of 1996 (the "Marshall Islands Act") states that a member or manager's "duties and liabilities may be expanded or restricted by provisions in a limited liability company agreement." As permitted by the Marshall Islands Act, our limited liability company agreement contains provisions that restrict the standards to which the Transocean Member and our directors and our officers may otherwise be held by Marshall Islands law. For example, our limited liability company agreement:

- provides that the Transocean Member may make determinations or take or decline to take actions without regard to our or our unitholders' interests. The Transocean Member may consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting us, our affiliates or our unitholders. Decisions made by the Transocean Member are made by persons acting only in the interest of its sole owner, Transocean. Specifically, the Transocean Member may, among other things, decide to exercise its call right, preemptive rights or registration rights, consent or withhold consent to any merger or consolidation of the company, appoint any directors or vote for the election of any director, vote or refrain from voting on amendments to our limited liability company agreement that require a vote of the outstanding units, voluntarily withdraw from the company, transfer, to the extent permitted under our limited liability company agreement, or refrain from transferring its units, the Transocean Member interest or incentive distribution rights or vote upon the dissolution of the company;
- provides that our directors and officers are entitled to make other decisions in "good faith," meaning they subjectively believe that the decision is in, or not adverse to, the best interests of the company;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of our board of directors and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be "fair and reasonable" to us and that, in determining whether a transaction or resolution is "fair and reasonable," our board of directors may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and
- provides that neither the Transocean Member nor our officers or our directors will be liable for monetary damages to us, our members or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the Transocean Member, our directors or officers or those other persons engaged in actual fraud or willful misconduct.

Fees and cost reimbursements, which certain affiliates of Transocean will determine for services provided to us and our subsidiaries, are substantial, are payable regardless of our profitability and will reduce our cash available for distribution to our unitholders.

Pursuant to the master services agreements and the support and secondment agreements we entered into with certain Transocean affiliates, we pay fees for services provided to us and our subsidiaries by certain affiliates of Transocean, and reimburse these entities for all expenses they incur on our behalf. These fees and expenses include all costs and expenses incurred in providing certain management, advisory, technical and administrative services to our subsidiaries. In addition, we are required to pay Transocean a services fee for providing services to us, other than third-party costs and expenses. We expect the amount of these fees and expenses to be approximately $43 million for the year ending December 31, 2015. There is no cap on the amount of fees and cost reimbursements that we and our subsidiaries may be required to pay such affiliates of Transocean pursuant to these agreements. The fees and expenses payable pursuant to these agreements are payable without regard to our financial condition or results of operations. The payment of fees to and the reimbursement of expenses of affiliates of Transocean could adversely affect our ability to pay cash distributions to our unitholders.

Our limited liability company agreement contains provisions that may have the effect of discouraging a person or group from attempting to remove our current management or the Transocean Member or acquiring the company, and even if public unitholders are dissatisfied, they will be unable to remove the Transocean Member without Transocean's consent, unless Transocean's ownership interest in us is decreased. The effect of such provisions could diminish the trading price of our common units.

Our limited liability company agreement contains provisions that may have the effect of discouraging a person or group from attempting to remove our current management or the Transocean Member.

- The unitholders will be unable initially to remove the Transocean Member without its consent because the Transocean Member and its affiliates will own sufficient units to be able to prevent its removal. The vote of the holders of at least 66 2⁄3 percent of all outstanding common and subordinated units voting together as a single class is required to remove the Transocean Member. Transocean owns 70.8 percent of our outstanding common and subordinated units.
- If the Transocean Member is removed without "cause" during the subordination period, which lasts until June 30, 2019, and units held by the Transocean Member and Transocean are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units, any existing arrearages on the common units will be extinguished, and the Transocean Member will have the right to convert its incentive distribution rights into common units or to receive cash in exchange for those interests based on the fair market value of those interests at the time. A removal of the Transocean Member under these circumstances would adversely affect the common units by prematurely eliminating their distribution and liquidation preference over the subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Any conversion of the Transocean Member interest or incentive distribution rights would be dilutive to existing unitholders. Furthermore, any cash payment in lieu of such conversion could be prohibitively expensive. "Cause" is narrowly defined to mean that with respect to a director or officer, a court of competent jurisdiction has entered a final, non-appealable judgment finding such director or officer liable for intentional fraud or willful misconduct, and with respect to the Transocean Member, the Transocean Member is in breach of the limited liability company agreement or a court of competent jurisdiction has entered a final, non-appealable judgment finding the Transocean Member liable for intentional fraud or willful misconduct against us or our members, in their capacity as such. Cause does not include most cases of charges of poor business decisions, such as charges of poor management of our business by the directors appointed by the Transocean Member, so the removal of the Transocean Member because of the unitholders' dissatisfaction with the Transocean Member's decisions in this regard would most likely result in the termination of the subordination period.
- Common unitholders, including the Transocean Member as a holder of common units, are entitled to elect only four of the seven members of our board of directors. The Transocean Member in its sole discretion is entitled to appoint the remaining three directors.
- Common unitholders that own 50 percent or more of our common units have the ability to request that cumulative voting be in effect for the election of elected directors. Following such a request, Transocean would generally be able to elect one or more of the elected directors even after it owns less than 50 percent of our common units.
- The Transocean Member can elect to classify our board of directors at any time. Thereafter, the election of the four directors elected by unitholders would be staggered, meaning that the members of only one of three classes of our elected directors will be selected each year. In addition, the directors appointed by the Transocean Member will serve for terms determined by the Transocean Member.
- Our limited liability company agreement contains provisions limiting the ability of unitholders to call meetings of unitholders, to nominate directors and to acquire information about our operations as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.
- There are no restrictions in our limited liability company agreement on our ability to issue additional equity securities.
- Although the Marshall Islands Act does not contain specific provisions regarding "business combinations" between limited companies organized under the laws of the Republic of Marshall Islands and "interested unitholders," our limited liability company agreement includes provisions that impose additional restrictions on our engaging in a business combination with an interested unitholder for a period of three years after the date of the transaction in which the person became an interested unitholder, subject to certain exceptions. Transocean and certain of its transferees are exempt from these additional restrictions.

The effect of these provisions may be to diminish the price at which the common units will trade.

The control of the Transocean Member may be transferred to a third party without unitholder consent.

The Transocean Member may transfer its Transocean Member interest to a third party without the consent of the unitholders. In addition, our limited liability company agreement does not restrict the ability of the members of the Transocean Member from transferring their respective limited liability company interests in the Transocean Member to a third party.

The incentive distribution rights of the Transocean Member may be transferred to a third party without unitholder consent.

The Transocean Member may transfer its incentive distribution rights to a third party at any time without the consent of our unitholders. If the Transocean Member transfers its incentive distribution rights to a third party, Transocean will have less incentive to grow our company and increase distributions. A transfer of incentive distribution rights by the Transocean Member could reduce the likelihood of Transocean selling or contributing additional assets to us, which in turn would impact our ability to grow our asset base.

Substantial future sales of our common units in the public market could cause the price of our common units to fall.

We have granted registration rights to Transocean and certain of its affiliates. These unitholders have the right, subject to some conditions, to require us to file registration statements covering any of our common, subordinated or other equity securities owned by them or to include those securities in registration statements that we may file for ourselves or other unitholders. Transocean owns 21.3 million of our common units and 27.6 million of our subordinated units and all of the incentive distribution rights, through its ownership of the Transocean Member. Following their registration and sale under the applicable registration statement, those securities will become freely tradable. By exercising their registration rights and selling a large number of common units or other securities, these unitholders could cause the price of our common units to decline.

We may issue additional equity securities, including securities senior to the common units, without unitholder approval, which would dilute existing unitholder ownership interests.

We may, without the approval of our unitholders, issue an unlimited number of additional units or other equity securities. In addition, we may issue an unlimited number of units that are senior to the common units in right of distribution, liquidation and voting. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Upon the expiration of the subordination period, the subordinated units will convert into common units and will then participate pro rata with other common units in distributions of available cash.

During the subordination period, the common units will have the right to receive distributions of available cash from operating surplus in an amount equal to the minimum quarterly distribution of $0.3625 per unit, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. Distribution arrearages do not accrue on the subordinated units. The purpose of the subordinated units is to increase the likelihood that during the subordination period there will be available cash from operating surplus to be distributed on the common units. Upon the expiration of the subordination period, the subordinated units will convert into common units and will then participate pro rata with other common units in distributions of available cash, which will dilute the amount of cash our existing common unit holders will receive.

The Transocean Member has a limited call right that may require you to sell your common units at an undesirable time or price.

If at any time the Transocean Member and its affiliates own more than 80 percent of the common units, the Transocean Member will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than the then-current market price of our common units. The Transocean Member is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon the exercise of this limited call right. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. Transocean, which owns and controls the Transocean Member, also owns 51.4 percent of our common units. At the end of the subordination period, assuming no additional issuances of common units and the conversion of our subordinated units into common units, Transocean will own 70.8 percent of our common units.

We can borrow money to pay distributions, which would reduce the amount of credit available to operate our business.

Our limited liability company agreement allows us to make working capital borrowings to pay distributions. Accordingly, if we have available borrowing capacity, we can make distributions on all our units even though cash generated by our operations may not be sufficient to pay such distributions. Any working capital borrowings by us to make distributions will reduce the amount of working capital borrowings we can make for operating our business.

Unitholders may have liability to repay distributions.

Under some circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under the Marshall Islands Act, we generally may not make a distribution to unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. The Marshall Islands Act provides that for a period of three years from the date of the impermissible distribution, members who received the distribution and who knew at the time of the distribution that it violated the Marshall Islands Act will be liable to the limited liability company for the distribution amount. Assignees who become substituted members are liable for the obligations of the assignor to make contributions to the company that are known to the assignee at the time it became a member and for unknown obligations if the liabilities could be determined from the limited liability company agreement. Liabilities to members on account of their limited liability company interest and liabilities that are non-recourse to the company are not counted for purposes of determining whether a distribution is permitted.

We incur increased costs as a result of being a publicly traded company.

We have little history operating as a public traded company. As a publicly traded company, we are subject to the public reporting requirements of the Exchange Act and we incur significant legal, accounting and other expenses that we did not incur as a private company. In addition, the Sarbanes-Oxley Act of 2002, as well as rules implemented by the SEC and the New York Stock Exchange ("NYSE") require publicly traded entities to adopt various corporate governance practices that will further increase our costs.

We also expect to incur significant expenses in order to obtain director and officer liability insurance. Because of the limitations in coverage for directors, it may be more difficult for us to attract and retain qualified persons to serve on our board or as executive officers.

We are a "controlled company" under the NYSE rules, and as such we are entitled to exemption from certain NYSE corporate governance standards, and you may not have the same protections afforded to stockholders of companies that are subject to all of the NYSE corporate governance requirements.

Transocean currently controls a majority of the voting power of our outstanding common units. As a result, we are a "controlled company" within the meaning of the NYSE corporate governance standards. Under the NYSE rules, a company of which more than 50 percent of the voting power for the election of directors is held by another company or group is a "controlled company" and may elect not to comply with certain NYSE corporate governance requirements, including (1) the requirement that a majority of the board of directors consist of independent directors, (2) the requirement that the nominating committee be composed entirely of independent directors and have a written charter addressing the committee's purpose and responsibilities, (3) the requirement that the compensation committee be composed entirely of independent directors and have a written charter addressing the committee's purpose and responsibilities and (4) the requirement of an annual performance evaluation of the nominating and compensation committees. Accordingly, in the future you may not have the same protections afforded to stockholders of companies that are subject to all of the NYSE corporate governance requirements.

We have been organized as a limited liability company under the laws of the Republic of the Marshall Islands, which does not have a well-developed body of limited liability company law.

Our limited liability company affairs are governed by our limited liability company agreement and by the Marshall Islands Act. The provisions of the Marshall Islands Act resemble provisions of the limited liability company laws of a number of states in the U.S., most notably Delaware. The Marshall Islands Act also provides that it is to be applied and construed to make it uniform with the laws of the State of Delaware and, so long as it does not conflict with the Marshall Islands Act or decisions of the Marshall Islands courts, the non-statutory law, or case law, of the State of Delaware is adopted as the law of the Marshall Islands. There have been, however, few, if any, court cases in the Marshall Islands interpreting the Marshall Islands Act, in contrast to Delaware, which has a fairly well-developed body of case law interpreting its limited liability company statute. Accordingly, we cannot predict whether Marshall Islands courts would reach the same conclusions as the courts in Delaware. For example, the rights of our unitholders and the duties of the Transocean Member and our directors and officers under Marshall Islands law are not as clearly established as under judicial precedent in existence in Delaware. As a result, unitholders may have more difficulty in protecting their interests in the face of actions by the Transocean Member and our officers and directors than would unitholders of a similarly organized limited liability company in the U.S.

Because we are organized under the laws of the Marshall Islands, it may be difficult to serve us with legal process or enforce judgments against us, our directors or our management.

We are organized under the laws of the Marshall Islands. In addition, the Transocean Member is a Cayman Islands exempted company, and a majority of our directors and some of our officers are or will be non-residents of the U.S., and all or a substantial portion of the assets of these non-residents are located outside the U.S. As a result, it may be difficult or impossible for unitholders to bring an action against us or against these individuals in the U.S. if unitholders believe that their rights have been infringed under securities laws or otherwise. Even if unitholders are successful in bringing an action of this kind, the laws of the Marshall Islands and of other jurisdictions may prevent or restrict unitholders from enforcing a judgment against our assets or the assets of the Transocean Member or our directors or officers.

Pursuant to the JOBS Act, our independent registered public accounting firm may not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002 for so long as we are an emerging growth company and we may take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards.

We will be required to disclose material changes made in our internal control over financial reporting on a quarterly basis and we will be required to assess the effectiveness of our controls annually. However, for as long as we are an "emerging growth company" under the JOBS Act, our independent registered public accounting firm may not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002. We could be an emerging growth company for up to five years. Effective internal controls are necessary for us to provide reliable and timely financial reports, prevent fraud and to operate successfully as a publicly traded limited liability company. We will prepare our consolidated financial statements in accordance with U.S. GAAP, but our internal controls over financial reporting may not meet all standards applicable to companies with publicly traded securities. Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future or to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. For example, Section 404 will require us, among other things, to annually review and report on the effectiveness of our internal control over financial reporting. We must comply with Section 404, except for the requirement for an auditor's attestation report, beginning with our fiscal year ending December 31, 2015. Any failure to develop, implement or maintain effective internal controls or to improve our internal controls could harm our operating results or cause us to fail to meet our reporting obligations.

Given the difficulties inherent in the design and operation of internal controls over financial reporting, in addition to our limited accounting personnel and management resources, we can provide no assurance as to our, or our independent registered public accounting firm's, future conclusions about the effectiveness of our internal controls, and we may incur significant costs in our efforts to comply with Section 404. Any failure to implement and maintain effective internal controls over financial reporting will subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business and would likely have a negative effect on the trading price of our common units.

In addition, Section 107 of the JOBS Act also provides that an "emerging growth company" can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards. In other words, an "emerging growth company" can delay the adoption of certain accounting standards until those standards would otherwise apply to private companies.

We may take advantage of these reporting exemptions until we are no longer an "emerging growth company." We cannot predict if investors will find our units less attractive because we will rely on these exemptions. If some investors find our units less attractive as a result, there may be a less active trading market for our units and our trading price may be more volatile.

Risks related to our taxes

A loss of a major tax dispute or a successful tax challenge to our operating structure, intercompany pricing policies or the taxable presence of our key subsidiaries in certain countries could result in a higher tax rate on our worldwide earnings, reducing our cash available for distribution to you.

Some of our subsidiaries are subject to tax in the jurisdictions in which they are organized or operate, reducing the amount of cash available for distribution. Our income taxes are based upon the applicable tax laws and tax rates in effect in the countries in which we operate and earn income as well as upon our operating structures in these countries.

In computing our tax obligations in these jurisdictions, we are required to take various tax accounting and reporting positions on matters that are not entirely free from doubt and for which we have not received rulings from the governing authorities. We cannot assure you that upon review of these positions the applicable authorities will agree with our positions. If a tax authority successfully challenges our operational structure, intercompany pricing policies or the taxable presence of our key subsidiaries in certain countries, or if the terms of certain income tax treaties are interpreted in a manner that is adverse to our structure, or if we lose a material tax dispute in any country, additional tax could be imposed on our subsidiaries, further reducing the cash available for distribution.

For example, the IRS has in prior periods challenged the transfer pricing used by Transocean for certain charters of drilling rigs—including our rigs—between its subsidiaries. Transocean has settled all challenges of this item for all years through its 2009 tax year with no material adjustments and it is currently contesting the proposed adjustments for its 2010 and 2011 tax years. However, if the IRS were to prevail in its challenge on this issue for Transocean's 2010 and 2011 tax years, Transocean's U.S. federal income tax liability could materially increase.

Our financial projections are based on transfer pricing policies that are substantively consistent with the resolution of this issue in Transocean's prior tax years. If the IRS were to challenge our transfer pricing for bareboat charter payments and be successful in such a challenge, our U.S. federal income tax liability could increase and there could be a material reduction in our cash available for distribution.

In addition, changes in our operations could result in additional tax being imposed on us or our subsidiaries in jurisdictions in which operations are conducted.

A change in tax laws, treaties or regulations, or their interpretation, of any country in which we have operations, are incorporated or are resident could result in a higher tax rate on our worldwide earnings, which could result in a significant negative impact on our earnings and cash flows from operations.

Over time, we are likely to operate in multiple jurisdictions through our subsidiaries. Consequently, we are subject to changes in applicable tax laws, treaties or regulations in the jurisdictions in which we operate, which could include laws or policies directed toward companies organized in jurisdictions with low tax rates. A material change in the tax laws, treaties or regulations, or their interpretation, of any country in which we have significant operations, or in which we are incorporated or resident, could result in a higher effective tax rate on our worldwide earnings, reducing the cash available for distribution. Potential changes include, but are not limited to, the examples described below.

For example, we and certain of our subsidiaries are or will be resident for tax purposes in the U.K. Changes to the income tax treaty in force between the U.S. and the U.K. could result in a higher effective tax rate on our worldwide earnings or require us to incur additional costs, reducing the cash available for distribution.

The U.K. could also enact changes to its tax laws or policies that could result in a higher effective tax rate on our worldwide earnings, thereby reducing the cash available for distribution. Such changes might include, but may not be limited to, changes in its taxation of earnings of subsidiaries or branches or withholding tax upon distributions to unitholders. In July 2014, legislation was enacted in the U.K. which will substantially increase the taxation of drilling contractors operating in the U.K. sector of the North Sea. In December 2014, the U.K. Treasury issued an additional draft legislative proposal that would impose an additional tax on certain aggressive tax planning techniques used by multinational entities to divert profits from the U.K. The U.K. authorities are expected to provide further guidance on the application of this proposed law to the drilling industry in late February. As we do not currently have any operations in the North Sea, this change is not expected to impact us, but other future legislative changes could adversely impact us.

In addition, in the U.S., a number legislative and budget proposals have been introduced that would substantially reform the U.S. international tax system. Any material change in tax laws resulting from these legislative proposals could result in a higher effective tax rate on our worldwide earnings, reducing the cash available for distribution and such changes could have a material adverse effect on our consolidated statements of financial position, results of operations or cash flows.

Similarly, the Organisation for Economic Co-Operation and Development (the "OECD") issued an action plan in July 2013 that called for member states to take action to prevent "base erosion and profit shifting" in situations where payments are made between affiliates from a jurisdiction with high tax rates to a jurisdiction with lower tax rates. A number of specific tax reform changes have been recently proposed and are currently being publicly debated. Some of these proposals would impact transfer pricing, requirements to qualify for tax treaty benefits, and the definition of permanent establishments. Any material change in tax laws or their interpretation, resulting from the OECD action plan could result in a higher effective tax rate on our worldwide earnings, reducing the cash available for distribution.

U.S. tax authorities could treat us as a passive foreign investment company, which would have adverse U.S. federal income tax consequences to U.S. unitholders.

If we were treated as a passive foreign investment company ("PFIC") for U.S. federal income tax purposes, U.S. unitholders would be subject to adverse U.S. federal income tax consequences with respect to certain distributions on our common units and the gain, if any, realized on the sale, exchange or other disposition of our common units. We would be treated as a PFIC for any taxable year in which either (i) at least 75 percent of our gross income consists of "passive income" (generally, dividends, interest, gains from the sale or exchange of investment property and certain rents and royalties) or (ii) the average percentage, based on quarterly measurements, of the value of our assets that produce, or are held for the production of, "passive income" is at least 50 percent. For purposes of these tests, we are deemed to own our proportionate share of the assets and to receive directly our proportionate share of the income of any other corporation in which we own, directly or indirectly, at least 25 percent of the value of the stock. In addition, income derived from the performance of services does not constitute "passive income." If we are treated as a PFIC for any taxable year during a U.S. unitholder's holding period in our common units, then such U.S. unitholder could be subject to adverse U.S. federal income tax consequences for that year and all subsequent taxable years in which the U.S. unitholder holds common units, even if we cease to be a PFIC.

We believe that we will not be a PFIC for our 2014 taxable year, and we expect that we will not be treated as a PFIC for any future taxable year. We have received an opinion of our U.S. counsel in support of this position that concludes that the income our subsidiaries earn from our present drilling contracts should not constitute passive income for purposes of determining whether we are a PFIC. In addition, we have represented to our U.S. counsel that we expect that more than 25 percent of our gross income for our 2014 taxable year and each future year will arise from such drilling contracts or other income our U.S. counsel has opined does not constitute passive income, and more than 50 percent of the average value of our assets for each such year will be held for the production of such non-passive income. Assuming the composition of our income and assets is consistent with these expectations, and assuming the accuracy of other representations we have made to our U.S. counsel for purposes of their opinion, our U.S. counsel is of the opinion that we should not be a PFIC for our 2014 taxable year or any future year.

While we have received an opinion of our U.S. counsel in support of our position, our counsel has advised us that the conclusions in this area are not free from doubt and the U.S. Internal Revenue Service ("IRS") or a court could disagree with this opinion and our position. In addition, although we intend to conduct our affairs in a manner to avoid being classified as a PFIC with respect to each taxable year, we cannot assure you that the nature of our operations will not change in the future and that we will not become a PFIC in any taxable year. See "Part II. Item 5. Market for Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities—Unitholder Matters—U.S. federal income tax considerations for U.S. holders—Passive foreign investment company status and significant tax consequences."

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Other than our drilling rigs, we do not own any material property. Our registered and principal executive offices are located at Deepwater House, Kingswells Causeway, Prime Four Business Park, Aberdeen, AB15 8PU, Scotland, United Kingdom, and our phone number is +44 1224 945 100.

Item 3. Legal Proceedings

In the future we may be, from time to time, involved in various litigation matters.

Item 4. Mine Safety Disclosures

Not applicable.

Executive Officers of the Registrant

We have included the following information, presented as of February 17, 2015, on our executive officers for purposes of U.S. securities laws in Part I of this report in reliance on General Instruction G(3) to Form 10-K.

We currently do not employ any of our executive officers and rely solely on Transocean to provide us with personnel who will perform executive officer services for our benefit pursuant to the support or secondment agreements and who will be responsible for our day-to-day management subject to the direction of our board of directors. Transocean also provides certain advisory and operational management services to our fleet and will provide management, administrative, financial and other support services to us pursuant to the master services agreements and the support or secondment agreements.

The board of directors elects the officers of the Company, generally on an annual basis. There is no family relationship between any of our executive officers.

Officer	Office	Age as of February 17, 2015
Kathleen S. McAllister	President and Chief Executive Officer	50
Garry Taylor	Chief Financial Officer	49

Kathleen S. McAllister has served as our President and Chief Executive Officer since June 2014 and was appointed as a director in July 2014. From June 2014 to July 2014, Ms. McAllister also served as our Interim Chief Financial Officer. From December 2011 to June 2014, Ms. McAllister served as Vice President and Treasurer of Transocean, and from March 2011 to December 2011, she served as Assistant Treasurer of Transocean. Ms. McAllister joined Transocean in August 2005 and served as Director of Tax Reporting until January 2008. She subsequently served as Finance Director for the Americas Business Unit and the North America Division from January 2008 to March 2011. Before joining Transocean, she served in various tax, treasury and finance roles at Helix Energy Solutions Group, Veritas DGC Inc. and Baker Hughes Inc. and began her career at Deloitte & Touche. Ms. McAllister earned a Bachelor of Science degree in Accounting from the University of Houston in 1989.

Garry Taylor has served as our Chief Financial Officer since July 2014 and has also served as Global Finance Director for Transocean since November 2012. He previously served as Finance Director for Transocean's Europe and Africa business unit from March 2011 to October 2012 and as Assistant Controller, Global Field Accounting from July 2009 to February 2011. Mr. Taylor joined Transocean in December 1998 as Finance and Administration Manager and has served in various finance and accounting positions of increasing responsibility throughout Transocean's global organization. Before joining Transocean, Mr. Taylor served in various finance roles for companies based in Aberdeen, Scotland. Mr. Taylor is a fellow of the Association of Chartered Certified Accountants. Mr. Taylor earned a Master of Arts degree in Accounting & Economics from the University of Aberdeen in 1987.

PART II

Item 5. Market for Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

Markets for Units of Our Common Equity

On July 31, 2014, we announced the pricing of the initial public offering of our common units representing limited liability company interests, which began trading on the New York Stock Exchange ("NYSE") under the ticker symbol "RIGP," for $22.00 per unit. On August 5, 2014, we completed the initial public offering of 20,125,000 common units, and Transocean Partners Holdings Limited (the "Transocean Member") received aggregate gross proceeds of $443 million. The following table presents the intraday high and low per unit sales prices of our common units as reported on the NYSE and per unit cash dividends declared to unitholders in the periods indicated.

	2014			2013		
	High	Low	Dividends	High	Low	Dividends
First quarter	$ —	$ —	$ —	$ —	$ —	$ —
Second quarter	—	—	—	—	—	—
Third quarter	29.43	21.90	—	—	—	—
Fourth quarter	27.24	13.18	0.2246	—	—	—

On February 17, 2015, the last reported sales price of our units on the NYSE was $16.78 per unit. On such date, there were two holders of record of our common units and 41,379,310 common units outstanding.

Unitholder Matters

Unregistered sales of equity securities and use of proceeds

On July 29, 2014, in connection with our initial public offering, Transocean Partners issued (a) to the Transocean Member (i) 41,379,310 common units and 27,586,207 subordinated units, representing a 60 percent and a 40 percent limited liability company interest in us, respectively, (ii) the non-economic interest, and (iii) all of the incentive distribution rights, which entitle the Transocean Member to increasing percentages of the cash that we distribute in excess of $0.416875 per unit per quarter, and (b) to an affiliate of the Transocean Member the 364-Day Working Capital Note Payable of $43 million for cash proceeds of $43 million, all or a portion of which we paid to the Transocean Member for our pro rata share of certain working capital balances. The foregoing transactions were undertaken in reliance upon the exemption from the registration requirements in Section 4(2) of the Securities Act of 1933. We believe that exemptions other than the foregoing exemption may exist for these transactions. Expenses related to the offering were paid by the Transocean Member. Transocean Partners did not receive any proceeds from the sale of the common units in the offering by the Transocean Member.

Unitholder distributions

On November 4, 2014, our board of directors approved a distribution of $0.2246 per unit to unitholders. On November 24, 2014, we made an aggregate cash payment of $15 million to our unitholders of record as of November 17, 2014, including an aggregate cash payment of $11 million to the Transocean Member.

U.S. federal income tax considerations for U.S. holders

Overview—We are treated as a corporation for U.S. federal income tax purposes. Consequently, among other things, U.S. Holders, as defined below, will not be directly subject to U.S. federal income tax on our income, but rather will be subject to U.S. federal income tax on certain distributions received from us and dispositions of units as described below.

The following is a discussion of the material U.S. federal income tax consequences that apply to U.S. Holders of our common units. As used herein, the term "U.S. Holder" means a beneficial owner of our common units that, for U.S. federal income tax purposes, is:

- an individual U.S. citizen or resident,
- a corporation (or other entity that is classified as a corporation) organized under the laws of the U.S. or any of its political subdivisions,
- an estate the income of which is subject to U.S. federal income taxation regardless of its source, or
- a trust if (i) a court within the U.S. is able to exercise primary jurisdiction over the administration of the trust and one or more U.S. persons have the authority to control all substantial decisions of the trust or (ii) the trust has a valid election in effect to be treated as a U.S. person for U.S. federal income tax purposes.

Unitholder distributions—Subject to the discussion under "—U.S. federal income tax considerations for U.S. holders—Passive foreign investment company status and significant tax consequences" below, the gross amount of any distributions to a U.S. Holder made by us with respect to our common units will constitute dividends to the extent of our current-year or accumulated earnings and profits, as determined under U.S. federal income tax principles. Distributions in excess of our current-year and accumulated earnings and profits will be treated first as a nontaxable return of capital to the extent of the U.S. Holder's tax basis in its common units and will reduce such basis, but not below zero. A distribution in excess of our current-year and accumulated earnings and profits and the U.S. Holder's tax basis in our common units will be treated as capital gain. U.S. Holders that are corporations generally will not be entitled to claim a dividends received deduction with respect to distributions they receive from us because we are not a U.S. corporation. Dividends received with respect to our common units generally will be treated as "passive category income" for purposes of computing allowable foreign tax credits for U.S. federal income tax purposes.

Generally, dividends paid with respect to our common units to a U.S. Holder that is an individual, trust or estate ("Non-Corporate U.S. Holder") will be treated as "qualified dividend income," which is taxable to such Non-Corporate U.S. Holder at preferential capital gain tax rates provided that: (i) the common units are readily tradable on an established securities market in the U.S., such as The New York Stock Exchange, or we are eligible for the benefits of a comprehensive income tax treaty with the U.S. that the IRS has determined is satisfactory and which includes an exchange of information program; (ii) we are not a passive foreign investment company ("PFIC") for the taxable year during which the dividend is paid or the immediately preceding taxable year, which we do not believe we are, have been or will be, as discussed below under "—U.S. federal income tax considerations for U.S. holders—Passive foreign investment company status and significant tax consequences"; (iii) the Non-Corporate U.S. Holder has owned the common units on which such dividends are paid for more than 60 days during the 121-day period beginning 60 days before the date on which the common units become ex-dividend, and has not entered into certain risk limiting transactions with respect to such common units; and (iv) the Non-Corporate U.S. Holder is not under an obligation to make related payments with respect to positions in substantially similar or related property. The preferential tax rate on dividends will not apply to dividends received to the extent that the Non-Corporate U.S. Holder elects to treat such dividends as "investment income," which may be offset by investment expense.

Special rules may apply to any dividends paid to a Non-Corporate U.S. Holder if such dividends are (i) treated as qualified dividend income eligible for the preferential tax rates described above and (ii) "extraordinary dividends." In general, an extraordinary dividend is any dividend with respect to a common unit if the amount of such dividend is equal to or in excess of 10 percent of a Non-Corporate U.S. Holder's adjusted tax basis, or fair market value upon such holder's election, in such common unit. In addition, extraordinary dividends include dividends that (i) have ex-dividend dates during the same period of 365 consecutive days and (ii) in the aggregate, equal or exceed 20 percent of a Non-Corporate U.S. Holder's adjusted tax basis, or fair market value upon such holder's election. If we pay an extraordinary dividend on our common units that is treated as qualified dividend income, then any loss recognized by a Non-Corporate U.S. Holder from the sale or exchange of such common units will be treated as long-term capital loss to the extent of the amount of such dividend.

Ratio of dividend income to distributions—We compute our earnings and profits for each taxable year in accordance with U.S. federal income tax principles. We estimate that less than 20 percent of the total cash distributions received by a holder of our common units that holds such common units through December 31, 2016 will constitute dividend income, which is subject to U.S. taxation in the manner described under "—U.S. federal income tax considerations for U.S. holders—Distributions" above. The remaining portion of these distributions, determined on a cumulative basis, will be treated first as a nontaxable return of capital to the extent of the purchaser's tax basis in its common units and thereafter as capital gain. These estimates are based upon the assumption that we will pay the minimum quarterly distribution of $0.3625 per unit on our common units during the referenced period and on other assumptions with respect to our earnings, capital expenditures and cash flow for this period. These estimates and assumptions are subject to, among other things, numerous business, economic, regulatory, competitive and political uncertainties that are beyond our control. Further, these estimates are based on current U.S. federal income tax law and tax reporting positions that we will adopt and with which the IRS could disagree. Accordingly, we cannot assure you that these estimates will prove to be correct. The actual percentage of total cash distributions that will constitute dividend income could be higher or lower, and any differences could be material or could materially affect the value of the common units.

Sale, exchange or other disposition of common units—Subject to the discussion under "—U.S. federal income tax considerations for U.S. holders—PFIC Status and Significant Tax Consequences" below, a U.S. Holder generally will recognize capital gain or loss upon a sale, exchange or other disposition of our units in an amount equal to the difference between the amount realized by the U.S. Holder from such sale, exchange or other disposition and the U.S. Holder's adjusted tax basis in such units. The U.S. Holder's initial tax basis in its units generally will be the U.S. Holder's purchase price for the units, and that tax basis will be reduced, but not below zero, by the amount of any distributions on the units that are treated as non-taxable returns of capital (see "—U.S. federal income tax considerations for U.S. holders—Distributions"). Such gain or loss will be treated as long-term capital gain or loss if the U.S. Holder's holding period is greater than one year at the time of the sale, exchange or other disposition. Non-Corporate U.S. Holders may be eligible for preferential rates of U.S. federal income tax in respect of long-term capital gains. A U.S. Holder's ability to deduct capital losses is subject to limitations. Such capital gain or loss generally will be treated as U.S. source income or loss, as applicable, for U.S. foreign tax credit purposes.

Passive foreign investment company status and significant tax consequences—The treatment of U.S. Holders could differ materially and adversely from that described above if, at any relevant time, we were a PFIC. For U.S. federal income tax purposes, we will be treated as a PFIC for any taxable year in which either:

- at least 75 percent of our gross income for such taxable year consists of passive income (generally, dividends, interest, gains from the sale or exchange of investment property and certain rents and royalties); or
- the average percentage, based on quarterly measurements, of the value of the assets held by us that produce, or are held for the production of, passive income is at least 50 percent.

For this purpose, we are deemed to own our proportionate share of the assets and to receive directly our proportionate share of the income of any other corporation, such as our drilling rig owning subsidiaries, in which we own, directly, or indirectly, at least 25 percent of the value of the stock. In addition, income earned, or deemed earned, by us in connection with the performance of services would not constitute passive income.

Based on our current and projected methods of operation, and an opinion of our U.S. counsel, Baker Botts L.L.P., we do not believe that we are or will be a PFIC with respect to any taxable year. We have received the opinion of our U.S. counsel in support of this position that concludes that the income our subsidiaries earn from our present drilling contracts should not constitute passive income for purposes of determining whether we are a PFIC. In addition, we have represented to our U.S. counsel that we expect that more than 25 percent of our gross income for our 2014 taxable year and each future year will arise from such drilling contracts or other income our U.S. counsel has opined does not constitute passive income, and more than 50 percent of the average value of our assets for each such year will be held for the production of such non-passive income. Assuming the composition of our income and assets is consistent with these expectations, and assuming the accuracy of other representations we have made to our U.S. counsel for purposes of their opinion, our U.S. counsel is of the opinion that we should not be a PFIC for our 2014 taxable year or any future year.

Distinguishing between contractual arrangements treated as generating rental income, which may constitute passive income for purposes of determining our PFIC status, and those treated as generating services income involves weighing and balancing competing factual considerations, and there is no legal authority under the PFIC rules addressing our specific method of operation. Conclusions in this area therefore remain matters of interpretation. We are not seeking a ruling from the IRS on the treatment of income generated from our drilling contracts or charters, and the opinion of our counsel is not binding on the IRS or any court. Thus, while we have received an opinion of counsel in support of our position, it is possible that the IRS or a court could disagree with this position. Moreover, although we intend to conduct our affairs in a manner to avoid being classified as a PFIC with respect to any taxable year, we cannot assure you that the nature of our operations will not change in the future and that we will not become a PFIC in any future year.

As discussed more fully below, if we were to be treated as a PFIC for any taxable year, a U.S. Holder would be subject to different taxation rules depending on whether or not the U.S. Holder makes (i) an election to treat us as a qualified electing fund ("QEF election") or (ii) a "mark-to-market" election with respect to our common units, as discussed below. If we are a PFIC, a U.S. Holder will be subject to the PFIC rules described herein with respect to any of our subsidiaries that are PFICs. However, the mark-to-market election discussed below will likely not be available with respect to shares of such PFIC subsidiaries. In addition, if a U.S. Holder owns our common units during any taxable year that we are a PFIC, such holder must file an annual report with the IRS.

Taxation of U.S. holders making a timely qualified electing fund election—If a U.S. Holder makes a timely QEF election (an "Electing Holder") in a taxable year, then for that and for all subsequent taxable years in which such holder has held the common units and we are a PFIC, the Electing Holder must include in income for such holder's taxable year its pro rata share of our ordinary earnings and net capital gain, if any, for our taxable years that end with or within the taxable year for which that holder is reporting, regardless of whether or not the Electing Holder received distributions from us in that year. The Electing Holder's adjusted tax basis in the common units will be increased to reflect taxed but undistributed earnings and profits. Distributions of earnings and profits that were previously taxed will result in a corresponding reduction in the Electing Holder's adjusted tax basis in common units and will not be taxed again once distributed. An Electing Holder generally will recognize capital gain or loss on the sale, exchange or other disposition of our common units. A U.S. Holder makes a QEF election with respect to any year that we are a PFIC by filing IRS Form 8621 with its U.S. federal income tax return. If contrary to our expectations, we determine that we are treated as a PFIC for any taxable year, we will endeavor, but will not be required, to provide each U.S. Holder with the information necessary to make the QEF election described above.

Taxation of U.S. holders making a "mark-to-market" election—If we were to be treated as a PFIC for any taxable year and, as we anticipate, our units were treated as "marketable stock," then, as an alternative to making a QEF election, a U.S. Holder would be allowed to make a "mark-to-market" election with respect to our common units, provided the U.S. Holder completes and files IRS Form 8621 in accordance with the relevant instructions and related Treasury Regulations. If that election is made, the U.S. Holder generally would include as ordinary income in each taxable year the excess, if any, of the fair market value of the U.S. Holder's common units at the end of the taxable year over the holder's adjusted tax basis in the common units. The U.S. Holder also would be permitted an ordinary loss in respect of the excess, if any, of the U.S. Holder's adjusted tax basis in the common units over the fair market value of the common units at the end of the taxable year, but only to the extent of the net amount previously included in income as a result of the mark-to-market election. A U.S. Holder's tax basis in its common units would be adjusted to reflect any such income or loss recognized. Gain recognized on the sale, exchange or other disposition of our common units would be treated as ordinary income, and any loss recognized on the sale, exchange or other disposition of the common units would be treated as ordinary loss to the extent that such loss does not exceed the net mark-to-market gains previously included in income by the U.S. Holder. Because the mark-to-market election only applies to marketable stock, however, it would not apply to a U.S. Holder's indirect interest in any of our subsidiaries that were determined to be PFICs.

Taxation of U.S. holders not making a timely qualifying electing fund election or mark-to-market election—If we were to be treated as a PFIC for any taxable year, a U.S. Holder that does not make either a QEF election or a mark-to-market election for that year or a Non-Electing Holder, would be subject to adverse tax rules with respect to (1) any excess distribution, generally, the portion of any distributions received by the Non-Electing Holder on our common units in a taxable year in excess of 125 percent of the average annual distributions received by the Non-Electing Holder in the three preceding taxable years or, if shorter, the Non-Electing Holder's holding period for the common units, and (2) any gain realized on the sale, exchange or other disposition of the units. Under these special rules:

- the excess distribution or gain would be allocated ratably over the Non-Electing Holder's aggregate holding period for the common units;
- the amount allocated to the current taxable year and any taxable year prior to the taxable year we were first treated as a PFIC with respect to the Non-Electing Holder would be taxed as ordinary income in the current year; and
- the amount allocated to each of the other taxable years would be subject to U.S. federal income tax at the highest rate of tax on ordinary income in effect for the applicable class of taxpayers for that year, and an interest charge for the deemed tax deferral benefit would be imposed with respect to the resulting tax liability as if that tax liability had been due for each such other taxable year.

Unless a Non-Electing Holder makes a QEF election or a mark-to-market election with respect to the common units, a Non-Electing Holder that holds common units during a period in which we are a PFIC will be subject to the rules described above for that period and all subsequent taxable years in which the Non-Electing Holder holds common units, even if we cease to be a PFIC. Classification as a PFIC may have other adverse tax consequences, including in the case of individual U.S. Holders, the denial of a step-up in the basis of the common units at death.

The PFIC rules are complex. U.S. Holders are urged to consult their tax advisors regarding the application of the PFIC rules to their investment in the common units and the advisability of choosing to make a QEF election or a mark-to-market election in the event we were to be treated as a PFIC.

U.S. federal income tax considerations for non-U.S. holders

Overview—The following is a discussion of the material U.S. federal income tax consequences that will apply to Non-U.S. Holders of our common units. As used herein, a "Non-U.S. Holder" means a beneficial owner of our common units, other than a partnership or an entity or arrangement treated as a partnership for U.S. federal income tax purposes, that is not a U.S. Holder.

Unitholder distributions—Distributions we pay to a Non-U.S. Holder with respect to the common units will not be subject to U.S. federal income tax or withholding tax unless the distributions are effectively connected with the Non-U.S. Holder's conduct of a U.S. trade or business, and, if an income tax treaty applies, such distributions are attributable to a U.S. permanent establishment maintained by the Non-U.S. Holder. Except to the extent otherwise provided under an applicable income tax treaty, a Non-U.S. Holder generally will be taxed in the same manner as a U.S. Holder on distributions that are effectively connected with the Non-U.S. Holder's conduct of a U.S. trade or business. Effectively connected distributions received by a corporate Non-U.S. Holder may also be subject to an additional U.S. branch profits tax at a 30 percent rate, or, if applicable, a lower treaty rate.

Sale, exchange or other disposition of common units—In general, a Non-U.S. Holder is not subject to U.S. federal income tax or withholding tax on any gain resulting from the sale, exchange or other disposition of our common units unless (i) the gain from the disposition of units is effectively connected with the Non-U.S. Holder's conduct of such U.S. trade or business, and, if an income tax treaty applies, such gain is attributable to a U.S. permanent establishment maintained by the Non-U.S. Holder or (ii) the Non U.S. Holder is an individual present in the U.S. for 183 days or more during the taxable year in which the gain is recognized and certain other conditions are met. Except to the extent otherwise provided under an applicable income tax treaty, a Non-U.S. Holder generally will be taxed in the same manner as a U.S. Holder on gains recognized that are effectively connected with the Non-U.S. Holder's conduct of a U.S. trade or business. Effectively connected gains recognized by a corporate Non-U.S. Holder may also be subject to an additional U.S. branch profits tax at a 30 percent rate, or, if applicable, a lower treaty rate.

U.S. Medicare tax

Certain U.S. Holders that are individuals, estates or trusts will be subject to an additional 3.8 percent tax, or the Medicare Tax, on all or a portion of their "net investment income," which may include all or a portion of the dividends on our common units and net capital gains from the disposition of our common units. U.S. Holders that are individuals, estates or trusts are urged to consult their tax advisors regarding the applicability of the Medicare Tax to their income and gains in respect of their investment in our common units.

Information reporting regarding foreign financial assets

Individual U.S. Holders that hold certain "foreign financial assets," which generally includes stock and other securities issued by a foreign person unless held in account maintained by a financial institution, that exceed certain thresholds are required to report to the IRS information relating to such assets. Under certain circumstances, an entity may be treated as an individual for purposes of these rules. Significant penalties may apply for failure to satisfy these reporting obligations. Individual U.S. Holders are urged to consult their tax advisors regarding the effect of these reporting obligations, if any, on their investment in our units.

Backup withholding and information reporting

In general, payments to a non-corporate U.S. Holder of distributions or the proceeds of a disposition of common units will be subject to information reporting. These payments to a non-corporate U.S. Holder also may be subject to backup withholding if the non-corporate U.S. Holder:

- fails to provide an accurate taxpayer identification number;
- is notified by the IRS that it has failed to report all interest or corporate distributions required to be reported on its U.S. federal income tax returns; or
- in certain circumstances, fails to comply with applicable certification requirements.

Non-U.S. Holders may be required to establish their exemption from information reporting and backup withholding by certifying their status on IRS Form W-8BEN, W-ECI or W-8IMY, as applicable.

Backup withholding is not an additional tax. Rather, a unitholder generally may obtain a credit for any amount withheld against its liability for U.S. federal income tax, and obtain a refund of any amounts withheld in excess of such liability, by timely filing a U.S. federal income tax return with the IRS.

Marshall Islands tax consequences

Because we and our subsidiaries do not and do not expect to conduct business or operations in the Republic of the Marshall Islands, under current Marshall Islands law, you will not be subject to Marshall Islands taxation or withholding on distributions, including upon distribution treated as a return of capital, we make to you as a unitholder. In addition, you will not be subject to Marshall Islands stamp, capital gains or other taxes on the purchase, ownership or disposition of common units, and you will not be required by the Republic of the Marshall Islands to file a tax return relating to your ownership of common units.

United Kingdom tax consequences

The following is a discussion of the material United Kingdom ("U.K.") tax consequences that may be relevant to prospective unitholders who are persons not resident for tax purposes in the U.K., and who are persons who have not been resident for tax purposes in the U.K. ("non-U.K. Holders").

Prospective unitholders who are, or have been, resident in the U.K. are urged to consult their own tax advisors regarding the potential U.K. tax consequences to them of an investment in our common units. For this purpose, a company incorporated outside of the U.K. will be treated as resident in the U.K. in the event its central management and control is carried out in the U.K.

The discussion that follows is based upon existing U.K. legislation and current H.M. Revenue & Customs practice as of the date of this annual report on Form 10-K, both of which may change, possibly with retroactive effect. Changes in these authorities may cause the tax consequences to vary substantially from the consequences of unit ownership described below.

We are not required to withhold U.K. tax when paying distributions to unitholders. Under U.K. taxation legislation, non-U.K. Holders will not be subject to tax in the U.K. on income or profits, including chargeable, or capital, gains, in respect of the acquisition, holding, disposition or redemption of the common units, provided that:

- such holders do not use or hold and are not deemed or considered to use or hold their common units in the course of carrying on a trade, profession or vocation in the U.K.; and
- such holders do not have a branch or agency or permanent establishment in the U.K. to which such common units are used, held or acquired.

A non-U.K. Holder that carries on a business in the U.K. through a partnership is subject to U.K. tax on income derived from the business carried on by the partnership in the U.K. Nonetheless, because we are organized as a limited liability company, and not a partnership, we expect that non-U.K. Holders will not be considered to be carrying on business in the U.K. for the purposes of U.K. taxation solely by reason of the acquisition, holding, disposition or redemption of their common units.

Issuer Purchases of Equity Securities

None.

Item 6. Selected Financial Data

The selected financial data as of December 31, 2014 and 2013 and for each of the three years in the period ended December 31, 2014 have been derived from the audited consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data." The following data should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the audited consolidated financial statements and the notes thereto included under "Item 8. Financial Statements and Supplementary Data."

For periods prior to August 5, 2014, the combined financial information of the Transocean Partners LLC predecessor was derived from Transocean's accounting records. The combined financial information reflects the combined results of operations, financial position and cash flows of the Transocean Partners LLC predecessor business as if such operations and assets had been combined for all periods presented. For the periods following August 5, 2014, the consolidated financial statements reflect our consolidated results of operations, financial position and cash flows. See Item 8. Financial Statements and Supplementary Information—Notes to Consolidated Financial Statements—Note 2—Significant Accounting Policies—Presentation.

As a company with less than $1 billion in revenues during our last fiscal year, we qualify as an emerging growth company as defined in the Jumpstart Our Business Startups Act of 2012. As an emerging growth company, we may, for up to five years, take advantage of specified exemptions from reporting and other regulatory requirements that are otherwise applicable generally to public companies. Among other exemptions, these include the presentation of only two years of audited financial statements and only two years of related Management's Discussion and Analysis of Financial Condition and Results of Operations in the registration statement of an initial public offering of common equity securities and the reporting of incremental years in the succeeding years for purposes of providing selected financial data.

	Years ended December 31,		
	2014	2013	2012
	(In millions, except per unit data)		
Statement of operations data			
Operating revenues	$ 567	$ 526	$ 569
Operating income	233	208	276
Net income	215	189	255
Net income attributable to controlling interest	36	n/a	n/a
Per unit earnings - basic and diluted			
Common units	$ 0.52	n/a	n/a
Subordinated units	$ 0.52	n/a	n/a
Balance sheet data (at end of period)			
Cash and cash equivalents	$ 86	$ —	$ —
Total assets	2,632	2,468	2,557
Debt due within one year	43	—	—
Total equity	2,451	2,344	2,388
Other financial data			
Cash provided by operating activities	$ 190	$ 239	$ 340
Cash used in investing activities	(3)	(4)	(15)
Cash used in financing activities	(101)	(235)	(325)
Capital expenditures	3	4	15
Distributions to common unitholders	9	n/a	n/a
Distributions to subordinated unitholders	6	n/a	n/a
Per share distributions to common unitholders	$ 0.2246	n/a	n/a
Per share distributions to subordinated unitholders	$ 0.2246	n/a	n/a

"n/a" means not applicable

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

The following information should be read in conjunction with the information contained in "Part I. Item 1. Business," "Part I. Item 1A. Risk Factors" and the audited consolidated financial statements and the notes thereto included under "Item 8. Financial Statements and Supplementary Data" in this annual report.

Business

Transocean Partners LLC (together with its subsidiaries and predecessors, unless the context requires otherwise, "Transocean Partners", "we", "us", or "our") is a growth-oriented limited liability company recently formed by Transocean Ltd. (together with its affiliates, unless the context requires otherwise, "Transocean") to own, operate and acquire modern, technologically advanced offshore drilling rigs. The drilling units in our fleet include the ultra-deepwater drillships *Discoverer Inspiration* and *Discoverer Clear Leader* and the ultra-deepwater semisubmersible *Development Driller III*, which are located in the U.S. Gulf of Mexico. We generate revenues through contract drilling services, which involves contracting our mobile offshore drilling fleet, related equipment and seconded work crews on a dayrate basis to drill oil and gas wells. We depend on Transocean affiliates to operate our drilling units, manage our customer relationships, renew existing and obtain new drilling contracts and to perform other administrative support activities.

On July 29, 2014, we entered into a contribution agreement with Transocean that gave effect to certain formation transactions, including Transocean's transfer of a 51 percent ownership interest in each of the entities that own and operate the drilling units in our fleet (each individually, a "RigCo", and collectively, the "RigCos"). Transocean holds the remaining 49 percent ownership interest in the RigCos. We completed the formation transactions on August 5, 2014.

On July 31, 2014, we announced the pricing of the initial public offering of our common units representing limited liability company interests, which began trading on the New York Stock Exchange under the ticker symbol "RIGP," for $22.00 per unit. On August 5, 2014, we completed the initial public offering of 20.1 million common units, including 2.6 million common units sold pursuant to the exercise in full of the underwriters' option to purchase additional common units, which represented a 29.2 percent limited liability company interest in Transocean Partners. Transocean Partners Holdings Limited (the "Transocean Member") holds the remaining 21.3 million common units and 27.6 million subordinated units, which collectively represented a 70.8 percent limited liability company interest. As a result of the offering, the Transocean Member received net cash proceeds of $417 million, net of $26 million for underwriting discounts and commissions and other offering costs.

The Transocean Partners LLC Predecessor (the "Predecessor") represents 100 percent of the combined results of operations, assets and liabilities of the drilling units in the fleet (the "Predecessor Business") prior to completion of the formation transactions and initial public offering on August 5, 2014. See Notes to Consolidated Financial Statements—Note 2—Significant Accounting Policies—Presentation.

Upon the completion of our formation transactions and initial public offering on August 5, 2014, we own a 51 percent interest in each of the RigCos. We control each RigCo through our ownership of the majority of its shares or limited liability company interests. The Transocean Member owns the remaining 49 percent noncontrolling interest in each of the RigCos.

The RigCos own the following three drilling rigs:

- the ultra-deepwater drillship *Discoverer Inspiration*, which commenced operations in 2010 and is currently under a contract with Chevron Corporation (together with its affiliates "Chevron") through April 2020;
- the ultra-deepwater drillship *Discoverer Clear Leader*, which commenced operations in 2009 and is currently under a contract with Chevron through October 2018; and
- the ultra-deepwater semi-submersible drilling rig *Development Driller III*, which commenced operations in 2009 and is currently under a contract with BP plc (together with its affiliates "BP") through November 2016.

We only own a 51 percent interest in each of the RigCos and thus will be entitled to only 51 percent of the RigCos' distributions, if any. Our interest in the RigCos represents our only cash-generating asset. We anticipate growing by acquiring additional drilling rigs and operations indirectly through additional rig-owning and rig-operating entities and by acquiring additional equity interests in the RigCos.

Although our contract drilling services operations are currently concentrated in the U.S. Gulf of Mexico, we can provide our services anywhere in the global offshore drilling market. Although rigs can be moved from one region to another, the cost of moving rigs and the availability of rig-moving vessels may cause the supply and demand balance to fluctuate somewhat between regions. Still, significant variations between regions do not tend to persist long term because of rig mobility. Our fleet operates in a single, global market for the provision of contract drilling services. The location of our rigs and the allocation of resources to operate or upgrade our rigs are determined by the activities and needs of our customers.

Significant Events

Formation and initial public offering—On July 29, 2014, we entered into a contribution agreement with Transocean and certain of its subsidiaries that gave effect to certain of the formation transactions, including the transfer of 51 percent of the ownership interest in each of the RigCos. On July 31, 2014, we announced the pricing of the initial public offering of our common units representing limited liability company interests, which began trading on the New York Stock Exchange under the ticker symbol "RIGP" for $22.00 per unit. On August 5, 2014, we completed the initial public offering of 20.1 million common units, including 2.6 million common units sold pursuant to the exercise in full of the underwriters' option to purchase additional common units, which represented a 29.2 percent limited liability company interest in Transocean Partners. In connection with our formation transactions, we entered into certain related party agreements with Transocean and certain of its affiliates. See Notes to Consolidated Financial Statements—Note 1—Nature of Business and Note 11—Related Party Transactions.

Working capital notes payable—On July 29, 2014, we entered into agreements with an affiliate of Transocean to establish a working capital note payable in the principal amount of $43 million that is due and payable at maturity on July 28, 2015. See "—Liquidity and Capital Resources—Sources and uses of liquidity."

Five-Year Revolving Credit Facility—On August 5, 2014, we entered into our current credit agreement, which is scheduled to expire on August 5, 2019, with a Transocean affiliate to establish a committed $300 million five-year revolving credit facility (the "Five-Year Revolving Credit Facility"). See "—Liquidity and Capital Resources—Sources and uses of liquidity."

Former credit agreements—On August 5, 2014, we terminated the credit agreements entered into with a Transocean affiliate prior to our initial public offering, and no borrowings were outstanding under the credit facilities at the time of termination. See "—Liquidity and Capital Resources—Sources and uses of liquidity."

Cash distributions to unitholders—On November 4, 2014, our board of directors approved a distribution of $0.2246 per unit to unitholders. On November 24, 2014, we made an aggregate cash payment of $15 million to our unitholders of record as of November 17, 2014, including an aggregate cash payment of $11 million to the Transocean Member.

On February 9, 2015, our board of directors approved a distribution of $0.3625 per unit to our unitholders. We expect to pay the aggregate cash distribution of $25 million on February 26, 2015 to unitholders of record as of February 20, 2015, including an aggregate cash payment of $18 million to the Transocean Member.

See "—Liquidity and Capital Resources—Sources and uses of liquidity."

Outlook

Drilling market—As of February 17, 2015, all three of our high-specification floaters were operating under existing long-term contracts with high-quality, creditworthy customers for an average remaining contract term of approximately 3.5 years, the shortest of which is contracted through November 2016. We believe continued exploration successes in the major deepwater offshore provinces and the emerging markets will generate additional future demand and support our long-term positive outlook for our high-specification floater fleet.

Although our long-term view of the offshore drilling market remains favorable, particularly for high-specification assets, we expect the near to medium term to be challenging, given customers' decisions to focus on capital allocation, reduce costs and delay various exploration and development programs. The significant and rapid decline in oil and natural gas prices has accelerated the rapid decline in demand across all markets. We currently expect the pace of contracts for the global floater fleet to remain slow in the near to medium term, resulting in excess capacity, lower dayrates and idle time for some rigs. Additionally, this excess capacity may result in some lower capability assets in the industry being permanently retired, ultimately reducing the available supply of drilling rigs, all else being equal.

As of February 17, 2015, uncommitted fleet rates for the years ending December 31, 2015, 2016, 2017, 2018 and 2019 were as follows:

	2015	2016	2017	2018	2019
Uncommitted fleet rate (a)					
Discoverer Inspiration	—%	—%	—%	—%	—%
Discoverer Clear Leader	—%	—%	—%	17%	100%
Development Driller III	—%	10%	100%	100%	100%

(a) The uncommitted fleet rate is defined as the number of uncommitted days divided by the total number of rig calendar days in the measurement period, expressed as a percentage. An uncommitted day is defined as a calendar day during which a rig is idle or stacked, is not contracted to a customer and is not committed to a shipyard.

Performance and Other Key Indicators

Contract backlog—Contract backlog is defined as the maximum contractual operating dayrate multiplied by the number of days remaining in the firm contract period, excluding revenues for mobilization, demobilization and contract preparation or other incentive provisions. Contract backlog represents the maximum contract drilling revenues that can be earned considering the contractual operating dayrate in effect during the firm contract period and represents the basis for the maximum revenues in our revenue efficiency measurement. To determine maximum revenues for purposes of calculating revenue efficiency, however, we include the revenues earned for mobilization, demobilization and contract preparation, other incentive provisions or cost escalation provisions, which are excluded from the amounts presented for contract backlog. The contract backlog for our contract drilling services was as follows:

Contract backlog	February 17, 2015	October 15, 2014	February 18, 2014
		(In millions)	
Discoverer Inspiration	$ 1,074	$ 1,140	$ 1,280
Discoverer Clear Leader	792	830	970
Development Driller III	277	330	420
Total fleet contract backlog	$ 2,143	$ 2,300	$ 2,670

Our contract backlog includes only firm commitments, which are represented by signed drilling contracts. The contractual operating dayrate may be higher than the actual dayrate we ultimately receive or an alternative contractual dayrate, such as a waiting-on-weather rate, repair rate, standby rate or force majeure rate, may apply under certain circumstances. The contractual operating dayrate may also be higher than the actual dayrate we ultimately receive because of a number of factors, including rig downtime or suspension of operations. In certain contracts, the dayrate may be reduced to zero if, for example, repairs extend beyond a stated period of time. The actual dayrate we receive may be higher than the contractual rate under certain circumstances, such as when cost escalation provisions are applied.

Average contractual dayrate relative to our contract backlog is defined as the maximum contractual operating dayrate to be earned per operating day in the measurement period. An operating day is defined as a day for which a rig is contracted to earn a dayrate during the firm contract period after commencement of operations.

At February 17, 2015, the contract backlog for our contract drilling services was as follows:

		For the years ending December 31,				
Contract backlog	Total	2015	2016	2017	2018	Thereafter
		(In millions, except average dayrates)				
Discoverer Inspiration	$ 1,074	$ 173	$ 214	$ 208	$ 214	$ 265
Discoverer Clear Leader	792	188	216	209	179	—
Development Driller III	277	136	141	—	—	—
Total fleet contract backlog	$ 2,143	$ 497	$ 571	$ 417	$ 393	$ 265

At February 17, 2015, our current contract terms, dayrates and customers were as follows:

Rig	Location	Contract term, dayrate and customer			
		Start date	Completion date	Dayrate	Customer
Discoverer Clear Leader	US Gulf of Mexico	November 2014	October 2018	$ 590,000	Chevron
Discoverer Inspiration	US Gulf of Mexico	February 2010	March 2015	$ 523,000	Chevron
		March 2015	March 2020	$ 585,000	Chevron
Development Driller III	US Gulf of Mexico	November 2009	November 2016	$ 431,000	BP

The actual amounts of revenues earned and the actual periods during which revenues are earned will differ from the amounts and periods shown in the tables above due to various factors, including shipyard and maintenance projects, unplanned downtime and other factors that result in lower applicable dayrates than the full contractual operating dayrate. Additional factors that could affect the amount and timing of actual revenue to be recognized include customer liquidity issues and contract terminations.

Average daily revenue—Average daily revenue is defined as contract drilling revenues earned per operating day. An operating day is defined as a calendar day during which a rig is contracted to earn a dayrate during the firm contract period after commencement of operations. The average daily revenue for our contract drilling services was as follows:

	Years ended December 31,		
	2014	2013	2012
Average daily revenue			
Discoverer Inspiration	$ 525,700	$ 500,700	$ 519,200
Discoverer Clear Leader	$ 522,300	$ 450,500	$ 527,900
Development Driller III	$ 460,600	$ 416,100	$ 437,000
Total fleet average daily revenue	$ 502,500	$ 455,800	$ 491,500

Our average daily revenue fluctuates primarily due to our revenue efficiency.

Revenue efficiency—Revenue efficiency is defined as actual contract drilling revenues for the measurement period divided by the maximum revenue calculated for the measurement period, expressed as a percentage. Maximum revenue is defined as the greatest amount of contract drilling revenues the drilling unit could earn for the measurement period, excluding amounts related to incentive provisions. The revenue efficiency rates for our contract drilling services were as follows:

	Years ended December 31,		
	2014	2013	2012
Revenue efficiency			
Discoverer Inspiration	97%	93%	98%
Discoverer Clear Leader	89%	77%	97%
Development Driller III	98%	90%	97%
Total fleet revenue efficiency	95%	86%	97%

Our revenue efficiency rate varies due to revenues earned under alternative contractual dayrates, such as a waiting-on-weather rate, repair rate, standby rate, force majeure rate or zero rate, that may apply under certain circumstances.

Revenue efficiency increased in the year ended December 31, 2014 relative to the year ended December 31, 2013 due to unplanned downtime in the prior year period associated primarily with repairs to blowout preventers and other subsea equipment, particularly with respect to *Discover Clear Leader* and *Development Driller III*. Correspondingly, revenue efficiency decreased in the year ended December 31, 2013 relative to the year ended December 31, 2012 primarily due to the same unplanned downtime.

Rig utilization—Rig utilization is defined as the total number of operating days divided by the total number of rig calendar days in the measurement period, expressed as a percentage. The rig utilization rates for our contract drilling services were as follows:

	Years ended December 31,		
	2014	2013	2012
Rig utilization			
Discoverer Inspiration	100%	100%	98%
Discoverer Clear Leader	95%	100%	100%
Development Driller III	100%	100%	100%
Total fleet average utilization	98%	100%	99%

Our rig utilization rate declines as a result of idle rigs and during shipyard and mobilization periods to the extent these rigs are not earning revenues. We remove rigs from the calculation upon disposal, classification as held for sale or classification as discontinued operations.

Operating Results

Year ended December 31, 2014 compared to the year ended December 31, 2013

The following is an analysis of our operating results from continuing operations. See "—Performance and Other Key Indicators" for definitions of operating days, average daily revenue, revenue efficiency and rig utilization.

	Years ended December 31, 2014	Years ended December 31, 2013	Change	% Change
	(In millions, except day amounts and percentages)			
Operating days	1,077	1,095	(18)	(2) %
Average daily revenue	$ 502,500	$ 455,800	$ 46,700	10 %
Revenue efficiency	95%	86%		
Rig utilization	98%	100%		
Contract drilling revenues	$ 557	$ 517	$ 40	8 %
Other revenues	10	9	1	11 %
	567	526	41	8 %
Operating and maintenance expense	(248)	(242)	(6)	(2) %
Depreciation expense	(66)	(66)	—	— %
General and administrative expense	(20)	(10)	(10)	(100) %
Operating income	233	208	25	12 %
Interest income	2	4	(2)	(50) %
Income before income tax expense	235	212	23	11 %
Income tax expense	(20)	(23)	3	13 %
Net income	$ 215	$ 189	$ 26	14 %

"n/m" means not meaningful.

Operating revenues—Contract drilling revenues increased for the year ended December 31, 2014 compared to the year ended December 31, 2013 primarily due to the following: (a) approximately $41 million of increased revenues due to higher revenue efficiency resulting from reduced downtime associated with blowout preventers and other subsea equipment, primarily on *Discoverer Clear Leader* and *Development Driller III*, and (b) approximately $8 million of increased revenues due to cost escalation provisions. Partially offsetting these increases was approximately $9 million of decreased revenues due to an 18-day out of service period for *Discoverer Clear Leader* associated with its five-year special periodic survey.

Costs and expenses—Operating and maintenance costs and expenses increased for the year ended December 31, 2014 compared to the year ended December 31, 2013 primarily due to the following: (a) approximately $6 million of increased costs and expenses due to blowout preventer recertification costs, (b) approximately $5 million of increased patent royalty expense resulting from increased revenues, and (c) approximately $5 million of increased costs and expenses resulting from riser joint overhaul and certification on *Development Driller III*. Partially offsetting these increases was (a) approximately $6 million of decreased personnel costs, and (b) approximately $4 million of decreased overhead allocations.

General and administrative expense increased for the year ended December 31, 2014 compared to the year ended December 31, 2013 due to increased costs and expenses related to establishing a separate publicly traded limited liability company.

Income tax expense—Consistent with the results of operations presented above, the following income tax data for the year ended December 31, 2014 was based on the Predecessor's tax structure for the period prior to August 5, 2014 and based on our tax structure for the period beginning on August 5, 2014. For the years ended December 31, 2014 and 2013, the annual effective tax rates were 8.5 percent and 10.7 percent, respectively, based on income before income taxes. The tax effect, if any, of the excluded items as well as settlements of prior year tax liabilities and changes in prior year tax estimates are all treated as discrete period tax expenses or benefits. For the years ended December 31, 2014 and 2013, the effect of the various discrete period tax items was a net tax expense of less than $1 million. For the years ended December 31, 2014 and 2013, the effective tax rates were 8.5 percent and 10.9 percent, respectively, based on income before income taxes, including these discrete tax items.

Year ended December 31, 2013 compared to the year ended December 31, 2012

The following is an analysis of our operating results from continuing operations. See "—Performance and Other Key Indicators" for definitions of operating days, average daily revenue, revenue efficiency and rig utilization.

	Years ended December 31, 2013	Years ended December 31, 2012	Change	% Change
	(In millions, except day amounts and percentages)			
Operating days	1,095	1,098	3	— %
Average daily revenue	$ 455,800	$ 491,500	$ (35,700)	(7) %
Revenue efficiency	86%	97%		
Rig utilization	100%	99%		
Contract drilling revenues	$ 517	$ 558	$ (41)	(7) %
Other revenues	9	11	(2)	(18) %
	526	569	(43)	(8) %
Operating and maintenance expense	(242)	(219)	(23)	(11) %
Depreciation expense	(66)	(65)	(1)	(2) %
General and administrative expense	(10)	(9)	(1)	(11) %
Operating income	208	276	(68)	(25) %
Interest income	4	3	1	33 %
Income before income tax expense	212	279	(67)	(24) %
Income tax expense	(23)	(24)	1	4 %
Net income	$ 189	$ 255	$ (66)	(26) %

"n/m" means not meaningful.

Operating revenues—Contract drilling revenues decreased for the year ended December 31, 2013 compared to the year ended December 31, 2012 primarily due to approximately $64 million of decreased revenues due to lower revenue efficiency caused by downtime associated primarily with repairs to blowout preventers and other subsea equipment on *Discoverer Clear Leader*. This decrease was partially offset by approximately $23 million of increased revenues due to improved contract terms and cost escalation provisions.

Costs and expenses—Operating and maintenance costs and expenses increased for the year ended December 31, 2013 compared to the year ended December 31, 2012 primarily due to the following: (a) approximately $9 million of increased personnel costs, (b) approximately $5 million of increased costs for allocated fleet costs on shared personnel and shared equipment, (c) approximately $4 million of increased costs for required well control system recertification and (d) approximately $4 million of increased costs for between well maintenance on subsea equipment, including the well control system.

Income tax expense—The following income tax data represents that of the Predecessor tax structure, which includes the subsidiaries of Transocean that have or had interests in the drilling rigs in our fleet and the associated rig-operating companies. For the years ended December 31, 2013 and 2012, our annual effective tax rates were 10.7 percent and 9.3 percent, respectively, based on income before income taxes. The tax effect of settlements of prior year tax liabilities and changes in prior year tax estimates are all treated as discrete period tax expenses or benefits. For the years ended December 31, 2013 and 2012, the effect of the various discrete period tax items was a net tax expense of less than $1 million, and a net tax benefit of $2 million, respectively. For the years ended December 31, 2013 and 2012, these discrete tax items resulted in effective tax rates of 10.9 percent and 8.6 percent, respectively, on income before income taxes.

Liquidity and Capital Resources

Sources and uses of cash

Transocean uses a centralized approach to treasury services to perform cash management for the operations of its affiliates. Under the Master Services Agreement, Transocean provides its treasury services to manage our cash and cash equivalents. The Predecessor had no bank accounts, and Transocean did not allocate its cash and cash equivalents to the Predecessor. The Predecessor transferred the cash generated and used by its operations to Transocean, and Transocean funded the Predecessor's operating and investing activities as needed. Accordingly, the Predecessor's transfers of cash to and from Transocean's treasury were presented as net distributions to the Predecessor's parent on our consolidated statements of equity and in our financing activities on our consolidated statements of cash flows.

The following table summarizes our net cash flows from operating, investing and financing activities for the years ended December 31, 2014 and 2013:

	Years ended December 31,		
	2014	2013	Change
	(In millions)		
Cash flows from operating activities			
Net cash provided by operating activities	$ 190	$ 239	$ (49)
Net cash used in investing activities	(3)	(4)	1
Net cash used in financing activities	(101)	(235)	134
	$ 86	$ —	$ 86

Net cash provided by operating activities decreased primarily due to changes in working capital.

Net cash used in financing activities decreased primarily due to the following: (a) decreased distributions to the Predecessor parent, (b) proceeds from a working capital note payable to affiliate, (c) a contribution for indemnification of lost revenues and (d) contributions resulting from our formation. Partially offsetting these decreases were the following: (a) a distribution of available cash to unitholders and (b) a disbursement to affiliates for a working capital adjustment.

Sources and uses of liquidity

Overview—We operate in a capital-intensive industry, and our primary liquidity needs are to finance the purchase of additional drilling rigs and other capital expenditures, fund investments, including the equity portion of investments in drilling rigs, fund working capital, maintain cash reserves against fluctuations in operating cash flows and pay distributions. We expect to fund our short-term liquidity needs through cash on hand, borrowings under credit facilities provided by Transocean affiliates, cash generated from operations and debt and equity financings.

We expect our ongoing sources of liquidity to include cash generated from operations, borrowings under our revolving credit facility and issuances of additional debt and equity securities. Generally, our long-term sources of funds will be cash from operations, long-term bank borrowings and other debt and equity financings. Because we will distribute all of our available cash, after deducting estimated maintenance, net of replacement capital expenditures, we expect to fund acquisitions and capital expenditures for expansion by relying on external financing sources, including bank borrowings and the issuance of debt and equity securities. We believe our current resources, including the potential borrowings under our credit facilities, are sufficient to meet our working capital requirements for our current business for at least the next year.

Our access to debt and equity markets may be limited due to a variety of events, including, among others, industry conditions, general economic conditions, market conditions and market perceptions of us and our industry. Our ability to access such markets may be restricted at a time when we would like, or need, to access such markets, which could have an impact on our flexibility to react to changing economic and business conditions. An economic downturn could have an impact on the lenders, including Transocean, participating in our credit facilities or on our customers, causing them to fail to meet their obligations to us.

We intend to pay a minimum quarterly distribution of $0.3625 per unit per quarter, which equates to approximately $25 million per quarter, or approximately $100 million per year in the aggregate, based on the number of outstanding common and subordinated units. At February 17, 2015, we had 41.4 million common units and 27.6 million subordinated units outstanding. We do not have a legal obligation to pay this distribution, and the amount declared by our board of directors may vary from this minimum quarterly distribution depending on expectations for future transactions and activities in which we may engage.

Estimated maintenance and replacement capital expenditures—Subject to the approval by the board of directors of each of the RigCos, each RigCo will transfer its available cash to its equityholders each quarter. In determining the amount of cash available for transfer, the board of directors of each of the RigCos and our board of directors determine the amount of cash reserves to set aside, including reserves for future maintenance and replacement capital expenditures, working capital and other matters. Because of the substantial capital expenditures the RigCos are required to make to maintain their fleets, the RigCos' initial annual estimated maintenance and replacement capital expenditures will be $69 million per year, which is comprised of $50 million for long-term maintenance and society classification surveys and $19 million, including financing costs, for replacing the rigs at the end of their useful lives.

The estimate of $19 million per year for future rig replacement is based on assumptions regarding the remaining useful life of the RigCos' rigs, a net investment rate applied on reserves, replacement values of the RigCos' rigs based on current market conditions, and the residual value of the rigs. The actual cost of replacing the rigs in the RigCos' fleet will depend on a number of factors, including prevailing market conditions, drilling contract operating dayrates and the availability and cost of financing at the time of replacement. Our limited liability company agreement allows our board of directors to deduct from our operating surplus each quarter estimated maintenance and replacement capital expenditures, as opposed to actual maintenance and replacement capital expenditures, in order to reduce disparities in operating surplus caused by fluctuating maintenance and replacement capital expenditures, such as society classification surveys and rig replacement. Our board of directors, with the approval of the conflicts committee, may determine that one or more of our assumptions should be revised, which could cause our board of directors to increase the amount of estimated maintenance and replacement capital expenditures. We may elect to finance some or all of our maintenance and replacement capital expenditures through the issuance of additional common units which could be dilutive to existing unitholders. As our fleet matures and expands, our long-term maintenance expenses will likely increase. See "Part I. Item 1A. Risk Factors—Risks related to our business—We must make substantial capital and operating expenditures to maintain the operating capacity of our fleet and our competitiveness, and to comply with laws and the applicable regulations and standards of governmental authorities and organizations, and to execute our growth plan, each of which could negatively affect our financial condition, results of operations and cash flows and reduce cash available for distribution." and "—If capital expenditures are financed through cash from operations or by issuing debt or equity securities, our ability to make cash distributions may be diminished, our financial leverage could increase or our unitholders could be diluted."

Revolving credit facilities—On August 5, 2014, we entered into a credit agreement, which is scheduled to expire on August 5, 2019, with a Transocean affiliate to establish a committed $300 million five-year revolving credit facility that allows for uncommitted increases in amounts agreed to by Transocean and us. We may borrow under the Five-Year Revolving Credit Facility at either (1) the adjusted London Interbank Offered Rate ("LIBOR") plus a margin (the "revolving credit facility margin"), which ranges from 1.625 percent to 2.250 percent based on our leverage ratio, as defined, or (2) the base rate specified in the credit agreement plus the revolving credit facility margin, less one percent per annum. Throughout the term of the Five-Year Revolving Credit Facility, we are required to pay a commitment fee on the daily unused amount of the underlying commitment, which ranges from 0.225 percent to 0.325 percent based on our leverage ratio, as defined. Among other things, the Five-Year Revolving Credit Facility includes limitations on creating liens, incurring subsidiary debt, transactions with affiliates, sale/leaseback transactions, mergers and the sale of substantially all assets. The Five-Year Revolving Credit Facility also includes a covenant imposing a maximum debt ratio, as defined in the agreement, with certain adjustments during a specified acquisition period. Borrowings under the Five-Year Revolving Credit Facility are subject to acceleration upon the occurrence of an event of default. At February 17, 2015, we had no borrowings outstanding and $300 million of available borrowing capacity under the Five-Year Revolving Credit Facility.

In March 2014, we entered into credit agreements with a Transocean affiliate, establishing credit facilities with an aggregate borrowing capacity of $300 million that were scheduled to expire on March 31, 2017. On August 5, 2014, we terminated these credit agreements with no borrowings outstanding under the credit facilities at the time of termination.

Working capital note payable—On July 29, 2014, we entered into agreements with a Transocean affiliate to establish a working capital note payable in the principal amount and for cash proceeds of $43 million that is due and payable at maturity on July 28, 2015. The working capital note payable bears interest at the adjusted one-month LIBOR plus a margin (the "working capital note margin"), which ranges from 1.625 percent to 2.250 percent based on our leverage ratio, as defined in the Five-Year Revolving Credit Facility. The principal amount may be repaid early without penalty, and amounts repaid cannot be reborrowed. At December 31, 2014, based on our leverage ratio on that date, the working capital note margin was 1.625 percent. At February 17, 2015, the outstanding principal amount under the working capital note payable was $43 million.

The assignment and bill of sale agreements for the acquisition contained a true-up mechanism whereby we will pay Transocean for the amount by which our pro rata share of actual net working capital, as determined within 60 days after the acquisition, exceeds our pro rata share of estimated net working capital at the time of the acquisition, and Transocean will pay us if such actual net working capital is less than such estimated net working capital. In December 2014, we paid to Transocean $5 million in satisfaction of the amount by which our pro rata share of actual net working capital exceeded the pro rata share of estimated net working capital at the time of the acquisition.

Transocean lost revenues indemnification—Under the Omnibus Agreement, Transocean agreed to indemnify us for any lost revenues, up to $100 million, arising out of the failure to receive an operating dayrate from Chevron for *Discoverer Clear Leader*, for the period commencing on the closing date of the offering through the completion of the rig's 2014 special periodic survey. In the year ended December 31, 2014, we submitted to Transocean claims for an aggregate amount of $19 million reimbursement under this indemnification clause, and we received payment of $9 million in October 2014. In January 2015, we received payment of the remaining $10 million outstanding under the indemnification clause.

Cash distributions to unitholders—On November 4, 2014, our board of directors approved a distribution of $0.2246 per unit to our unitholders. On November 24, 2014, we made an aggregate cash payment of $15 million to our unitholders of record as of November 17, 2014, including an aggregate cash payment of $11 million to the Transocean Member. The approved distribution amount was based on the minimum quarterly distribution for the proportional period from the date of the closing of the initial public offering through September 30, 2014.

On February 9, 2015, our board of directors approved a distribution of $0.3625 per unit to our unitholders. We expect to pay the aggregate cash distribution of $25 million on February 26, 2015 to unitholders of record as of February 20, 2015, including an aggregate cash payment of $18 million to the Transocean Member.

Contractual obligations—At December 31, 2014, our contractual obligations stated at face value, were as follows:

	For the years ending December 31,				
	Total	2015	2016 - 2017	2018 - 2019	Thereafter
			(in millions)		
Contractual obligations					
Debt	$ 43	$ 43	$ —	$ —	$ —
Purchase obligations	23	23	—	—	—
Total (a)	$ 66	$ 66	$ —	$ —	$ —

(a) As of December 31, 2014, our unrecognized tax benefits related to uncertain tax positions, net of prepayments, represented a liability of less than $1 million. Due to the high degree of uncertainty regarding the timing of future cash outflows associated with the liabilities recognized in this balance, we are unable to make reasonably reliable estimates of the period of cash settlement with the respective taxing authorities, and we have excluded this amount from the contractual obligations presented in the table above. See Notes to Consolidated Financial Statements—Note 4—Income Taxes.

Contingencies

Insurance matters

Our fleet is covered under Transocean's hull and machinery and excess liability insurance program, which is comprised of commercial market and captive insurance policies, and Transocean allocates to us the premium costs attributable to our fleet. Transocean renews the commercial and captive policies under its insurance program annually on May 1. At February 17, 2015, our drilling units had an insured value of approximately $2.0 billion under this program. Above applicable deductibles, Transocean carries an aggregate of $750 million of excess liability limits, which is shared among the rigs in the Transocean fleet, including the rigs in our fleet. See Notes to Consolidated Financial Statements—Note 8—Commitments and Contingencies.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements as of December 31, 2014.

Related Party Transactions

Overview—Upon the completion of our formation transactions and initial public offering on August 5, 2014, Transocean owns 21.3 million common units and 27.6 million subordinated units, representing a 70.8 percent limited liability company interest in us, and all of our incentive distribution rights. Transocean also owns the non-economic interest in us that includes the right to appoint three of the seven members of our board of directors. Under our limited liability company agreement, common unitholders that own 50 percent or more of our common units have the ability to request that cumulative voting be in effect for the election of elected directors. Cumulative voting is an irrevocable election that allows for the unitholder to allocate its votes cumulatively, rather than proportionally. Therefore, for so long as Transocean owns 50 percent or more of our common units, it will have the ability to request that cumulative voting be in effect for the election of elected directors, which would enable Transocean to elect one or more of the elected directors even after it owns less than 50 percent of our common units. As a result, if cumulative voting was in effect, Transocean would have the ability to appoint the majority of our board as long as it retains at least 20 percent of our common units. The directors appointed by Transocean may designate a member of the board of directors to be the chairman of the board of directors. Specific rights of the Transocean Members are designated in our limited liability company agreement.

We, Transocean and certain of its affiliates entered into various agreements that gave effect to our formation, ongoing operational and administrative support and financing arrangements, which were not the result of arm's-length negotiations and they may not be on terms at least as favorable to the parties to these agreements as they could have obtained from unaffiliated parties. See Notes to Consolidated Financial Statements—Note 11—Related Party Transactions.

Procedures for review, approval and ratification of related person transactions—Our board of directors adopted a related party transactions policy that provides that our board of directors or its authorized committee will review all related person transactions that are required to be disclosed under SEC rules and, when appropriate, authorize or ratify all such transactions. In the event that our board of directors or its authorized committee considers ratification of a related person transaction and determines not to so ratify, the related party transactions policy provides that our management will make all reasonable efforts to cancel or annul the transaction.

The related party transactions policy provides that, in determining whether or not to recommend the approval or ratification of a related person transaction, our board of directors or its authorized committee should consider all of the relevant facts and circumstances available, including but not limited to:

- whether there is an appropriate business justification for the transaction;
- the benefits that accrue to us as a result of the transaction;
- the terms available to unrelated third parties entering into similar transactions;
- the impact of the transaction on a director's independence, in the event the related person is a director, an immediate family member of a director or an entity in which a director or an immediate family member of a director is a partner, unitholder, member or executive officer;
- the availability of other sources for comparable products or services;
- whether it is a single transaction or a series of ongoing, related transactions; and
- whether entering into the transaction would be consistent with the code of business conduct and ethics.

Critical Accounting Policies and Estimates

Overview—We prepared our consolidated financial statements in accordance with accounting principles generally accepted in the U.S., which require us to make estimates that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures of contingent assets and liabilities. On an ongoing basis, we evaluate our estimates, including those related to our allowance for doubtful accounts, materials and supplies obsolescence, property and equipment, goodwill, income taxes and contingent liabilities. These estimates require significant judgments and assumptions. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying amounts of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates.

We consider the following to be our critical accounting policies and estimates, and we have discussed the development, selection and disclosure of such policies and estimates with the audit committee of our board of directors. For a discussion of our significant accounting policies, refer to our Notes to Consolidated Financial Statements—Note 2—Significant Accounting Policies.

Allocated indirect and overhead costs—We, Transocean and certain of its affiliates entered into various agreements that gave effect to our formation, ongoing operational and administrative support and financing arrangements. In connection with such agreements, Transocean allocates to us costs and expenses related to the services performed and products provided to us under the master service and support agreements. Transocean allocates costs to us based on its accounting policies, applying a variety of methods, including management time sheets, head count, purchasing activities or rig operating activities. The allocations require significant judgment and subjectivity in applying estimates and assumptions used to determine the amount of such allocations, including the method of allocation, and the amount of time, services and resources provided to us relative to those provided to other Transocean affiliates. Altering the assumptions used in our cost allocation estimates could result in significantly different results. In the year ended December 31, 2014, costs and expenses allocated to us by Transocean were $19 million. See Notes to Consolidated Financial Statements—Note 2—Significant Accounting Policies and Note 11—Related Party Transactions.

Income taxes—We are organized as a limited liability company under the laws of the Republic of the Marshall Islands and are resident in the U.K. for taxation purposes. We are treated as a corporation for U.S. federal income tax purposes. Certain of our controlled affiliates are subject to taxation in the jurisdictions in which they are organized, conduct business or own assets. For this purpose, controlled affiliates include our rig-owning and rig-operating subsidiaries.

The Republic of the Marshall Islands—Because we and our controlled affiliates do not conduct business or operations in the Republic of the Marshall Islands, neither we nor our controlled affiliates are subject to income, capital gains, profits or other taxation under current Marshall Islands law. As a result, any distributions from our controlled affiliates are not subject to Marshall Islands taxation.

United Kingdom—We and certain of our controlled affiliates are residents of the U.K. for taxation purposes. Any distributions from our controlled affiliates generally are exempt from taxation in the U.K. under the applicable exemption for distributions from subsidiaries. As a result, we do not expect to be subject to a material amount of taxation in the U.K. as a consequence of our U.K. residency for tax purposes.

United States—We and our controlled affiliates are treated as corporations for U.S. federal income tax purposes. As a result, we and our controlled affiliates are subject to U.S. federal income tax to the extent we earn (i) certain types of income from U.S. sources or (ii) income that is treated as effectively connected with the conduct of a trade or business in the U.S. and attributable to a permanent establishment in the U.S. We do not expect to earn a material amount of such income. Certain of our controlled affiliates, however, conduct drilling operations in the U.S. Gulf of Mexico and are subject to taxation by the U.S. on their net income.

Cayman Islands—The Cayman Islands does not impose any income, capital gains, profits, withholding or other taxation on us, our controlled affiliates or on any distributions we or they may make.

Our tax liability in any given year could be affected by changes in tax laws, regulations, agreements, and treaties, currency exchange restrictions or our level of operations or profitability in each jurisdiction. Although our annual tax provision is based on the best information available at the time, a number of years may elapse before the ultimate tax liabilities in the various jurisdictions are determined.

We maintain liabilities for estimated tax exposures in our jurisdictions of operation, and the provisions and benefits resulting from changes to those liabilities are included in our annual tax provision along with related interest. Tax exposure items may include potential challenges to permanent establishment positions, intercompany pricing, disposition transactions, and withholding tax rates and their applicability. These exposures are resolved primarily through the settlement of audits within these tax jurisdictions or by judicial means, but can also be affected by changes in applicable tax law or other factors, which could cause us to revise past estimates. A loss of a major tax dispute or a successful tax challenge to our transfer pricing policies in certain countries could materially affect our tax liability in a given year.

We review our liabilities on an ongoing basis and, to the extent audits or other events cause us to adjust the liabilities accrued in prior periods, we recognize those adjustments in the period of the event. We do not believe it is possible to reasonably estimate the future impact of changes to the assumptions and estimates related to our annual tax provision because changes to our tax liabilities are dependent on numerous factors that cannot be reasonably projected. These factors include, among others, the amount and nature of additional taxes potentially asserted by local tax authorities; the willingness of local tax authorities to negotiate a fair settlement through an administrative process; the impartiality of the local courts; and the potential for changes in the taxes paid to one country that either produce, or fail to produce, offsetting tax changes in other countries.

Estimates, judgments and assumptions are required in determining whether deferred tax assets will be fully or partially realized. When it is estimated to be more likely than not that all or some portion of certain deferred tax assets, such as foreign tax credit carryovers or net operating loss carryforwards, will not be realized, we establish a valuation allowance for the amount of the deferred tax assets that is considered to be unrealizable. We continually evaluate strategies that could allow for the future utilization of our deferred tax assets.

Transocean has agreed to indemnify us for any tax liabilities we or our subsidiaries may incur with respect to operations of the Predecessor. Transocean operated the assets of the Predecessor through its subsidiaries in the U.S. and Switzerland, and we have provided for income taxes based upon the tax laws and rates in the countries in which we operate and earn income. The Predecessor's annual tax provision was based on expected taxable income, statutory rates and tax planning opportunities available to it in the various jurisdictions in which it operated and earned income. The determination of the Predecessor's annual tax provision and evaluation of their tax positions involves interpretation of tax laws in the various jurisdictions and requires significant judgment and the use of estimates and assumptions regarding significant future events, such as the amount, timing and character of income, deductions and tax credits. Transocean is currently undergoing examinations in the U.S. for fiscal years 2010 and 2011. At December 31, 2014, the carrying amount of our liability for estimated tax exposures in our jurisdictions of operation was approximately $1 million. At December 31, 2013, the Predecessor's carrying amount of liability for estimated tax exposures, originated in legal entities that were not transferred to us in the formation transactions, was approximately $13 million.

See Notes to Consolidated Financial Statements—Note 4—Income Taxes.

Property and equipment—The carrying amount of property and equipment is subject to various estimates, assumptions, and judgments related to capitalized costs, useful lives and salvage values and impairments. At December 31, 2014 and 2013, the carrying amount of our property and equipment was $2.0 billion, representing 75 percent and 83 percent of our total assets, respectively.

Capitalized costs—We capitalize costs incurred to enhance, improve and extend the useful lives of our property and equipment and expense costs incurred to repair and maintain the existing condition of our rigs. Capitalized costs increase the carrying amounts and depreciation expense of the related assets, which also impact our results of operations.

Useful lives and salvage values—We depreciate our assets using the straight-line method over their estimated useful 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, rig utilization and asset performance. Useful lives and salvage values of rigs are difficult to estimate due to a variety of factors, including (a) technological advances that impact the methods or cost of oil and gas exploration and development, (b) changes in market or economic conditions, and (c) changes in laws or regulations affecting the drilling industry. Applying different judgments and assumptions in establishing the useful lives and salvage values would likely result in materially different net carrying amounts and depreciation expense for our assets. We reevaluate the remaining useful lives and salvage values of our rigs when certain events occur that directly impact the useful lives and salvage values of the rigs, including changes in operating condition, functional capability and market and economic factors. When evaluating the remaining useful lives of rigs, we also consider major capital upgrades required to perform certain contracts and the long-term impact of those upgrades on future marketability. At December 31, 2014, a hypothetical one-year increase in the useful lives of all of our rigs would cause a decrease in our annual depreciation expense of approximately $2 million and a hypothetical one-year decrease would cause an increase in our annual depreciation expense of approximately $2 million.

Long-lived asset impairment—We review the aggregate carrying amount of our long-lived assets, principally property and equipment, for potential impairment when events occur or circumstances change that indicate that the aggregate carrying amount of the drilling units and related equipment in our asset group may not be recoverable. We determine recoverability by evaluating the aggregate estimated undiscounted future net cash flows based on projected dayrates and utilization of our drilling units. When an impairment of our assets is indicated, we measure the impairment as the amount by which the aggregate carrying amount of the drilling units and related equipment in our asset group exceeds the aggregate estimated fair value. We measure the fair value of our drilling units and related equipment by applying a variety of valuation methods, incorporating a combination of income and market approaches, using projected discounted cash flows and estimates of the exchange price that would be received for the assets in the principal or most advantageous market for the assets in an orderly transaction between market participants as of the measurement date.

Goodwill impairment—We conduct impairment testing for our goodwill annually as of October 1 and more frequently, on an interim basis, when an event occurs or circumstances change that indicate that the fair value of a reporting unit or the indefinite-lived intangible asset may have declined below its carrying value. We test goodwill at the reporting unit level, which is defined as an operating segment or one level below an operating segment that constitutes a business for which financial information is available and is regularly reviewed by management. We have determined that we have a single reporting unit for this purpose.

Before testing goodwill, we consider whether or not to first assess qualitative factors to determine whether the existence of events or circumstances lead to a determination that it is more likely than not that the fair value of a reporting unit is less than its carrying amount and whether the two-step impairment test is required. If, as the result of our qualitative assessment, we determine that the two-step impairment test is required, or, alternatively, if we elect to forgo the qualitative assessment, we test goodwill for impairment by comparing the carrying amount of the reporting unit, including goodwill, to the fair value of the reporting unit.

We estimate the fair value of our reporting unit using a variety of valuation methods, incorporating both income and market approaches, including projected discounted cash flows, publicly traded company multiples and acquisition multiples. To develop the projected cash flows associated with our reporting unit, which are based on estimated future dayrates and rig utilization, we consider key factors that include assumptions regarding future commodity prices, credit market conditions and the effect these factors may have on our contract drilling operations and the capital expenditure budgets of our customers. We discount the projected cash flows using a long-term, risk-adjusted weighted-average cost of capital, which is based on our estimate of the investment returns that market participants would require for our reporting unit. We derive publicly traded company multiples for companies with operations similar to our reporting units using observable information related to shares traded on stock exchanges and, when available, observable information related to recent acquisitions. If the reporting unit's carrying amount exceeds its fair value, we consider goodwill impaired and perform a second step to measure the amount of the impairment loss, if any.

Because our business is cyclical in nature, the results of our impairment testing are expected to vary significantly depending on the timing of the assessment relative to the business cycle. Altering either the timing of or assumptions used in our reporting unit's fair value calculations could result in an estimate that is significantly below its carrying amount, which may indicate its goodwill is impaired. During the three months ended December 31, 2014, we observed a rapid and significant decline in the market value of our stock, the market value of Transocean's stock, prices of oil and natural gas and the actual and projected declines in dayrates and utilization, and we considered these indicators that the fair value of our goodwill could have fallen below its carrying amount, and as a result, we performed an interim goodwill impairment test. Although we determined that our goodwill was not impaired as of December 31, 2014, we concluded that our reporting unit was at risk of failing the first step of our goodwill impairment test, as the reporting unit's estimated fair value exceeded its carrying amount by less than 5 percent. If the market value of our stock declines below its previous 52-week low or if we experience increasingly unfavorable changes to actual or anticipated market conditions, or to other impairment indicators, any of which may result in the fair value of our reporting unit falling below its carrying amount, we may be required to recognize losses on impairment of goodwill in the near future. In the years ended December 31, 2014 and 2013, as a result of our annual impairment testing, we concluded that our goodwill was not impaired. At December 31, 2014 we had $356 million of goodwill, representing 14 percent of our total assets, that had been allocated to us by Transocean in connection with our formation. At December 31, 2013, the Predecessor had $213 million of goodwill that had been allocated to it prior to our formation.

New Accounting Pronouncements

For a discussion of the new accounting pronouncements that have had or are expected to have an effect on our consolidated financial statements, see Notes to Consolidated Financial Statements—Note 3—New Accounting Pronouncements.

Jumpstart Our Business Startups Act of 2012

We qualify as an emerging growth company, as defined in the Jumpstart Our Business Startups Act of 2012 (the "JOBS Act"). As an emerging growth company, we may, for up to five years, take advantage of specified exemptions from reporting and other regulatory requirements that are otherwise applicable generally to public companies, including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404(b) of the Sarbanes-Oxley Act, reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements, exemptions from the requirements of holding advisory say-on-pay votes on executive compensation and shareholder advisory votes on golden parachute compensation. In addition, Section 107 of the JOBS Act also provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards. An emerging growth company can, therefore, delay the adoption of certain accounting standards until those standards would otherwise apply to private companies.

We have elected to take advantage of all of the applicable JOBS Act exemptions, including the exemption provided by Section 107 of the JOBS Act, as described above. This election to take advantage of the extended transition period for complying with new or revised financial accounting standards is irrevocable. Accordingly, the information that we provide you may be different than what you may receive from other public companies in which you hold equity interests.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Credit risk—We have only two customers. The market for our services is the offshore oil and gas industry, and the customers consist primarily of major oil and gas companies, independent oil and gas producers and government-owned oil companies. Ongoing credit evaluations of our customers are performed and generally do not require collateral in our business agreements. Reserves for potential credit losses are maintained when necessary.

Interest rate risk—At December 31, 2014, we had a working capital note payable to a Transocean affiliate with an aggregate outstanding principal amount of $43 million. The principal amount of the working capital note payable bears interest at a variable rate and exposes us to interest rate risk. Based upon the variable-rate debt amount outstanding as of December 31, 2014, a hypothetical one percentage point change in annual interest rates would result in a corresponding change in annual interest expense of less than $1 million.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Unitholders of Transocean Partners LLC

We have audited the accompanying consolidated balance sheets of Transocean Partners LLC and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of operations, equity, and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Transocean Partners LLC and subsidiaries at December 31, 2014 and 2013, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Houston, Texas

February 26, 2015

TRANSOCEAN PARTNERS LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(In millions, except per unit data)

	Years ended December 31,		
	2014	2013	2012
Operating revenues			
Contract drilling revenues	$ 557	$ 517	$ 558
Other revenues	10	9	11
	567	526	569
Costs and expenses			
Operating and maintenance	248	242	219
Depreciation	66	66	65
General and administrative	20	10	9
	334	318	293
Operating income	233	208	276
Other income (expense), net			
Interest income	3	4	3
Interest expense	(1)	—	—
	2	4	3
Income before income tax expense	235	212	279
Income tax expense	20	23	24
Net income	215	$ 189	$ 255
Net income attributable to Predecessor	135		
Net income subsequent to initial public offering	80		
Net income attributable to noncontrolling interest	44		
Net income attributable to controlling interest	$ 36		
Earnings per unit - basic and diluted			
Earnings per common unit	$ 0.52		
Earnings per subordinated unit	$ 0.52		
Weighted-average units outstanding			
Common units	41		
Subordinated units	28		

See accompanying notes.

TRANSOCEAN PARTNERS LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In millions, except unit data)

	December 31, 2014	December 31, 2013
Assets		
Cash and cash equivalents	$ 86	$ —
Accounts receivable	112	103
Accounts receivable from affiliates	28	—
Materials and supplies, net	41	34
Deferred income taxes, net	8	15
Prepaid assets	6	7
Total current assets	281	159
Property and equipment	2,302	2,309
Less accumulated depreciation	(336)	(271)
Property and equipment, net	1,966	2,038
Goodwill	356	213
Deferred income taxes, net	7	29
Other assets	22	29
Total assets	$ 2,632	$ 2,468
Liabilities and equity		
Accounts payable to affiliates	$ 76	$ —
Debt due to affiliates within one year	43	—
Deferred revenues	18	37
Other current liabilities	1	—
Total current liabilities	138	37
Long-term tax liability	1	13
Deferred revenues	13	30
Drilling contract intangible liability	29	44
Total long-term liabilities	43	87
Commitments and contingencies		
Common units, 41,379,310 authorized, issued and outstanding at December 31, 2014	847	—
Subordinated units, 27,586,207 authorized, issued and outstanding at December 31, 2014	564	—
Total members' equity	1,411	—
Net investment	—	2,344
Noncontrolling interest	1,040	—
Total equity	2,451	2,344
Total liabilities and equity	$ 2,632	$ 2,468

See accompanying notes.

TRANSOCEAN PARTNERS LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY
(In millions)

	Years ended December 31,		
	2014	2013	2012
Common units			
Balance, beginning of period	$ —	$ —	$ —
Allocation of net investment	821	—	—
Net income attributable to controlling interest	22	—	—
Contribution for parent payment of dual-activity patent royalties	4	—	—
Contribution for parent indemnification of lost revenues	11	—	—
Distribution of available cash to unitholders	(9)	—	—
Distribution for working capital adjustment	(2)	—	—
Balance, end of period	$ 847	$ —	$ —
Subordinated units			
Balance, beginning of period	$ —	$ —	$ —
Allocation of net investment	547	—	—
Net income attributable to controlling interest	14	—	—
Contribution for parent payment of dual-activity patent royalties	3	—	—
Contribution for parent indemnification of lost revenues	8	—	—
Distribution of available cash to unitholders	(6)	—	—
Distribution for working capital adjustment	(2)	—	—
Balance, end of period	$ 564	$ —	$ —
Total members' equity			
Balance, beginning of period	$ —	$ —	$ —
Allocation of net investment	1,368	—	—
Net income attributable to controlling interest	36	—	—
Contribution for parent payment of dual-activity patent royalties	7	—	—
Contribution for parent indemnification of lost revenues	19	—	—
Distribution of available cash to unitholders	(15)	—	—
Distribution for working capital adjustment	(4)	—	—
Balance, end of period	$ 1,411	$ —	$ —
Net investment			
Balance, beginning of period	$ 2,344	$ 2,388	$ 2,443
Net income attributable to the Predecessor	135	189	255
Distributions to the Predecessor parent, net	(115)	(233)	(310)
Effect of formation transactions	(996)	—	—
Allocation of net investment	(1,368)	—	—
Balance, end of period	$ —	$ 2,344	$ 2,388
Noncontrolling interest			
Balance, beginning of period	$ —	$ —	$ —
Effect of formation transactions	996	—	—
Net income attributable to noncontrolling interest	44	—	—
Balance, end of period	$ 1,040	$ —	$ —
Total equity			
Balance, beginning of period	$ 2,344	$ 2,388	$ 2,443
Net income attributable to the Predecessor	135	189	255
Net income subsequent to initial public offering	80	—	—
Contribution for parent payment of dual-activity patent royalties	7	—	—
Contribution for parent indemnification of lost revenues	19	—	—
Distributions to Predecessor parent, net	(115)	(233)	(310)
Distribution of available cash to unitholders	(15)	—	—
Distribution for working capital adjustment	(4)	—	—
Balance, end of period	$ 2,451	$ 2,344	$ 2,388

See accompanying notes.

TRANSOCEAN PARTNERS LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Years ended December 31,		
	2014	2013	2012
Cash flows from operating activities			
Net income	$ 215	$ 189	$ 255
Adjustments to reconcile to net cash provided by operating activities			
Amortization of drilling contract intangible	(15)	(18)	(19)
Depreciation	66	66	65
Patent royalties expense	7	—	—
Deferred income taxes	18	15	21
Other, net	—	1	1
Changes in deferred revenues, net	(36)	(29)	(38)
Changes in deferred costs, net	(4)	4	3
Changes in operating assets and liabilities			
Decrease in accounts receivable, net	4	22	55
Increase in materials and supplies, net	(8)	(13)	(5)
Decrease in balances due to affiliates, net	(60)	—	—
Increase in income tax liability, net	3	2	2
Net cash provided by operating activities	190	239	340
Cash flows from investing activities			
Capital expenditures	(3)	(4)	(15)
Net cash used in investing activities	(3)	(4)	(15)
Cash flows from financing activities			
Proceeds from working capital note payable to affiliate	43	—	—
Proceeds from affiliates for indemnification	9	—	—
Contributions resulting from formation transactions	8	—	—
Disbursement to affiliates for working capital adjustment	(5)	—	—
Distribution of available cash to unitholders	(15)	—	—
Distributions to the Predecessor parent, net	(141)	(235)	(325)
Net cash used in financing activities	(101)	(235)	(325)
Net increase in cash and cash equivalents	86	—	—
Cash and cash equivalents at beginning of period	—	—	—
Cash and cash equivalents at end of period	$ 86	$ —	$ —

See accompanying notes.

Note 1—Business

Transocean Partners LLC ("Transocean Partners", "we", "us", or "our"), a Marshall Islands limited liability company, was formed on February 6, 2014, by Transocean Partners Holdings Limited, a wholly owned subsidiary of Transocean Ltd. (together with its affiliates, unless the context requires otherwise, "Transocean"), to own, operate and acquire modern, technologically advanced offshore drilling rigs. The drilling units in our fleet include the ultra-deepwater drillships *Discoverer Inspiration* and *Discoverer Clear Leader* and the ultra-deepwater semisubmersible *Development Driller III*, which are located in the United States ("U.S.") Gulf of Mexico.

On July 29, 2014, we entered into a contribution agreement with Transocean that gave effect to certain formation transactions, including Transocean's transfer of a 51 percent ownership interest in each of the entities that own and operate the drilling units in our fleet (each individually, a "RigCo", and collectively, the "RigCos"). Transocean holds the remaining 49 percent ownership interest in the RigCos. We completed the formation transactions on August 5, 2014.

On July 31, 2014, we announced the pricing of the initial public offering of our common units representing limited liability company interests, which began trading on the New York Stock Exchange under the ticker symbol "RIGP," for $22.00 per unit. On August 5, 2014, we completed the initial public offering of 20.1 million common units, including 2.6 million common units sold pursuant to the exercise in full of the underwriters' option to purchase additional common units, which represented a 29.2 percent limited liability company interest in Transocean Partners. Transocean Partners Holdings Limited (the "Transocean Member") holds the remaining 21.3 million common units and 27.6 million subordinated units, which collectively represented a 70.8 percent limited liability company interest, and all of our incentive distribution rights. As a result of the offering, the Transocean Member received net cash proceeds of $417 million, net of $26 million for underwriting discounts and commissions and other offering costs.

The Transocean Partners LLC Predecessor (the "Predecessor") represents 100 percent of the combined results of operations, assets and liabilities of the drilling units in the fleet (the "Predecessor Business") prior to completion of the formation transactions and initial public offering on August 5, 2014.

Note 2—Significant Accounting Policies

Presentation—For periods prior to August 5, 2014, the combined financial information of the Predecessor was derived from Transocean's accounting records. The combined financial information reflects the combined results of operations, financial position and cash flows of the Predecessor Business as if such operations and assets had been combined for all periods presented. All transactions among the Predecessor Business within the Predecessor have been eliminated.

For the periods following August 5, 2014, the consolidated financial statements reflect our consolidated results of operations, financial position and cash flows. We have presented our assets and liabilities at historical cost because the Predecessor transferred to us such assets and liabilities in formation transactions completed under common control within the Transocean consolidated group. We present in our consolidated financial statements 100 percent of our consolidated results of operations, assets, liabilities and cash flows, and we present the Transocean's partial ownership interest in each of the RigCos as noncontrolling interest.

Transocean uses a centralized approach to treasury services to perform cash management for the operations of its affiliates. Under the Master Services Agreement, Transocean provides its treasury services to manage our cash and cash equivalents. The Predecessor had no bank accounts, and Transocean did not allocate its cash and cash equivalents to the Predecessor. The Predecessor transferred the cash generated and used by its operations to Transocean, and Transocean funded the Predecessor's operating and investing activities as needed. Accordingly, the Predecessor's transfers of cash to and from Transocean's treasury were presented as net distributions to the Predecessor's parent on our consolidated statements of equity and in our financing activities on our consolidated statements of cash flows. The Predecessor's results of operations do not include any interest expense for intercompany cash advances from Transocean, since Transocean did not historically allocate interest expense for intercompany advances to the Predecessor.

Accordingly, we have prepared our consolidated financial statements on the following basis:

- Our consolidated statement of operations for the year ended December 31, 2014 consists of the consolidated results of operations of Transocean Partners for the period from August 5, 2014 through December 31, 2014 and the combined results of operations of the Predecessor for the beginning of the period through August 4, 2014. Our consolidated statements of operations for the years ended December 31, 2013 and 2012 consist entirely of the combined results of operations of the Predecessor.
- Our consolidated balance sheet at December 31, 2014 consists of the consolidated balances of Transocean Partners. Our consolidated balance sheet at December 31, 2013 consists of the combined balances of the Predecessor.
- Our consolidated statement of equity for the year ended December 31, 2014 consists of the consolidated activity of Transocean Partners during and following the formation on August 5, 2014 and the combined activity of the Predecessor through August 4, 2014. Our consolidated statements of equity for the years ended December 31, 2013 and 2012 consist entirely of the combined activity of the Predecessor.
- Our consolidated statement of cash flows for the year ended December 31, 2014 consists of the consolidated cash flows of Transocean Partners for the period from August 5, 2014 through December 31, 2014 and the combined cash flows of the Predecessor for the beginning of the respective period through August 4, 2014. Our consolidated statements of cash flows for the years ended December 31, 2013 and 2012 consist entirely of the combined cash flows of the Predecessor.

Accounting estimates—To prepare financial statements in accordance with accounting principles generally accepted in the U.S., we are required to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosures of contingent assets and liabilities. On an ongoing basis, we evaluate our estimates and assumptions, including those related to our materials and supplies obsolescence, property and equipment, goodwill and drilling contract intangible liability, income taxes, allocated costs and related party transactions. We base our estimates and assumptions on historical experience and on various other factors we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying amounts of assets and liabilities that are not readily apparent from other sources. Actual results could differ from such estimates.

Fair value measurements—We estimate fair value at a price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the principal market for the asset or liability. Our valuation techniques require inputs that we categorize using a three-level hierarchy, from highest to lowest level of observable inputs, as follows: (1) significant observable inputs, including unadjusted quoted prices for identical assets or liabilities in active markets ("Level 1"), (2) significant other observable inputs, including direct or indirect market data for similar assets or liabilities in active markets or identical assets or liabilities in less active markets ("Level 2") and (3) significant unobservable inputs, including those that require considerable judgment for which there is little or no market data ("Level 3"). When multiple input levels are required for a valuation, we categorize the entire fair value measurement according to the lowest level of input that is significant to the measurement even though we may have also utilized significant inputs that are more readily observable.

Consolidation—We consolidate entities in which we have a majority voting interest and entities that meet the criteria for variable interest entities for which we are deemed to be the primary beneficiary for accounting purposes. We eliminate intercompany transactions and accounts in consolidation. We apply the equity method of accounting for an investment in an entity if we have the ability to exercise significant influence over the entity that (a) does not meet the variable interest entity criteria or (b) meets the variable interest entity criteria, but for which we are not deemed to be the primary beneficiary. We apply the cost method of accounting for an investment in an entity if we do not have the ability to exercise significant influence over the unconsolidated entity. We separately present within equity on our consolidated balance sheets the ownership interests attributable to parties with noncontrolling interests in our consolidated subsidiaries, and we separately present net income attributable to such parties on our consolidated statements of operations.

Operating revenues and expenses—We recognize operating revenues as they are realized and earned and can be reasonably measured, based on contractual dayrates, and when collectability is reasonably assured. In connection with drilling contracts, we may receive revenues for preparation and mobilization of equipment and personnel or for capital improvements to rigs. We defer the revenues earned and incremental costs incurred that are directly related to contract preparation and mobilization and recognize such revenues and costs over the primary contract term of the drilling project using the straight-line method. We amortize, in operating and maintenance costs and expenses, the fees related to contract preparation and mobilization on a straight-line basis over the estimated firm period of drilling, which is consistent with the general pace of activity, level of services being provided and dayrates being earned over the life of the contract. For contractual daily rate contracts, we recognize the losses for loss contracts as such losses are incurred. We recognize the costs of relocating drilling units without contracts as such costs are incurred. Upon completion of drilling contracts, we recognize in earnings any demobilization fees received and expenses incurred. We defer capital upgrade revenues received and recognize such revenues over the primary contract term of the drilling project. We depreciate the actual costs incurred for the capital upgrade on a straight-line basis over the estimated useful life of the asset. We defer the periodic survey and drydock costs incurred in connection with obtaining regulatory certification to operate our rigs and well control systems on an ongoing basis, and we recognize such costs over the period until expiration of certification using the straight-line method. We defer costs associated with the license fee that we paid for the use of Transocean's patented dual-activity and recognize such amortized costs using the straight-line method through the license and patent expiration in May 2016 (see Note 11—Related Party Transactions).

Included in our contract drilling revenues, we recognize amortization associated with our drilling contract intangible liability attributed to the drilling contract for *Development Driller III*. We amortize drilling contract intangible revenues based on the cash flows projected over the contract period and include such revenues in contract drilling revenues on our consolidated statements of operations. See Note 5—Goodwill and Intangible Liability.

Our other revenues represent those derived from customer reimbursable revenues. We recognize customer reimbursable revenues as we bill our customers for reimbursement of costs associated with certain equipment, materials and supplies, subcontracted services, employee bonuses and other expenditures, resulting in little or no net effect on operating income since such recognition is concurrent with the recognition of the respective reimbursable costs in operating and maintenance expense.

Allocated indirect and overhead costs—Our results of operations include allocations of costs and expenses based on services performed and products provided by Transocean under master service and support agreements. In connection with such agreements, Transocean allocates to us costs and expenses related to the services performed and products provided to us under the master service and support agreements. The allocations require significant judgment and subjectivity in applying estimates and assumptions used to determine the amount of such allocations, including the amount of time, services and resources provided to us relative to that provided to other Transocean affiliates. Altering the assumptions used in our cost allocation estimates could result in significantly different results. In the year ended December 31, 2014, costs and expenses allocated to us by Transocean were $19 million (see Note 11—Related Party Transactions).

The combined results of operations for the Predecessor include allocated indirect and overhead costs for certain functions historically performed by Transocean and not previously allocated to the Predecessor Business, including allocations of indirect operating and maintenance costs and expenses for onshore operational support services such as engineering, procurement and logistics and general and administrative costs and expenses related to executive oversight, accounting, treasury, tax, legal, and information technology. We have applied these allocations based on relative values of net property and equipment and operating and maintenance costs and expenses. We believe the assumptions underlying the consolidated financial statements, including the assumptions regarding allocation of costs from Transocean, are reasonable. Nevertheless, the combined results of operations of the Predecessor do not include all of the costs that the Predecessor would have incurred had it been a stand-alone company during the periods presented and may not reflect the combined results of operations, financial position and cash flows had the Predecessor been a stand-alone company during the periods presented. In the years ended December 31, 2014, 2013 and 2012, the Predecessor recognized such allocated operating and maintenance costs of $14 million, $28 million and $22 million, respectively, including $11 million, $21 million and $17 million, respectively, for personnel costs. In the years ended December 31, 2014, 2013 and 2012, we recognized such allocated general and administrative costs of $6 million, $10 million and $9 million, respectively, including $4 million, $6 million and $6 million, respectively, for personnel costs.

Income taxes—We provide for income taxes based upon the tax laws and rates in effect in the countries in which operations are conducted and income is earned. We recognize deferred tax assets and liabilities for the anticipated future tax effects of temporary differences between the financial statement basis and the tax basis of our assets and liabilities using the applicable jurisdictional tax rates in effect at year end. We record a valuation allowance for deferred tax assets when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. We also record a valuation allowance for deferred tax assets resulting from net operating losses incurred during the year in certain jurisdictions and for other deferred tax assets where, in our opinion, it is more likely than not that the financial statement benefit of these losses will not be realized. Additionally, we record a valuation allowance for foreign tax credit carryforwards to reflect the possible expiration of these benefits prior to their utilization.

We maintain liabilities for estimated tax exposures in our jurisdictions of operation, and we recognize the provisions and benefits resulting from changes to those liabilities in our income tax expense or benefit along with related interest and penalties. Tax exposure items may include potential challenges to qualification for treaty benefits, intercompany pricing, disposition transactions, and withholding tax rates and their applicability. These tax exposures are resolved primarily through the settlement of audits within these tax jurisdictions or by judicial means, but can also be affected by changes in applicable tax law or other factors, which could cause us to revise past estimates. The U.S. Internal Revenue Service (the "IRS") has previously challenged and is currently challenging Transocean's transfer pricing relating to certain bareboat charters. If the IRS successfully challenged our transfer pricing policies, it could result in a material increase in our U.S. federal income tax expense. See Note 4—Income Taxes.

Earnings per unit—We apply the two-class method of calculating earnings per unit for our participating securities, including our common units, subordinated units and our incentive distribution rights.

Under our limited liability company agreement, we established a cash distribution policy that requires the distribution of our available cash, which is determined by our board of directors (see Note 9—Cash Distributions). To calculate the earnings per unit for our common and subordinated unitholders, we allocate our net income or loss attributable to controlling interest for the quarterly or annual period in proportion to the respective ownership interest or, if the application of our cash distribution policy results in disproportionate distribution, in accordance with such policy. We present earnings per unit regardless of whether such earnings would or could be distributed under the terms of our limited liability company agreement. Accordingly, the reported earnings per unit is not indicative of potential cash distributions that may be made based on historical or future earnings.

See Note 5—Earnings Per Unit.

Cash and cash equivalents—We consider cash equivalents to include highly liquid debt instruments with original maturities of three months or less, such as time deposits with commercial banks that have high credit ratings, U.S. Treasury and government securities, Eurodollar time deposits, certificates of deposit and commercial paper. We may also invest excess funds in no-load, open-ended, management investment trusts. Such management trusts invest exclusively in high-quality money market instruments.

Accounts receivable—We derive a majority of our revenues from services to international oil companies. We evaluate the credit quality of our customers on an ongoing basis, and we do not generally require collateral or other security to support customer receivables. We establish an allowance for doubtful accounts on a case-by-case basis, considering changes in the financial position of a customer, when we believe the required payment of specific amounts owed to us is unlikely to occur. At December 31, 2014 and 2013, we had no allowance for doubtful accounts.

We record long-term accounts receivable at their present value and recognize interest income using the effective interest method through the date of payment. At December 31, 2014 and 2013, the aggregate face value of our long-term accounts receivable was $24 million and $50 million, respectively. At December 31, 2014, the aggregate carrying amount of our long-term accounts receivable was $22 million, including $12 million and $10 million, recorded in accounts receivable and other assets, respectively. At December 31, 2013, the aggregate carrying amount of our long-term accounts receivable was $45 million, including $23 million and $22 million, respectively, recorded in accounts receivable and other assets, respectively. At December 31, 2014 and 2013, our long-term accounts receivable had weighted average effective interest rates of 11 percent and 10 percent, respectively.

Materials and supplies—We record materials and supplies at their average cost less an allowance for obsolescence. We estimate the allowance for obsolescence based on historical experience and expectations for future use of the materials and supplies. At December 31, 2014 and 2013, the allowance for obsolescence was $3 million and $2 million, respectively.

Property and equipment—The carrying amounts of our property and equipment, consisting primarily of offshore drilling rigs and related equipment, are based on our estimates, assumptions and judgments relative to capitalized costs, useful lives and salvage values of our rigs. These estimates, assumptions and judgments reflect both historical experience and expectations regarding future industry conditions and operations. At December 31, 2014, the aggregate carrying amount of our property and equipment represented approximately 75 percent of our total assets.

We compute depreciation using the straight-line method after allowing for salvage values. We capitalize expenditures for newbuilds, renewals, replacements and improvements, including capitalized interest, if applicable, and we recognize the expense for maintenance and repair costs as incurred. Upon sale or other disposition of an asset, we recognize a net gain or loss on disposal of the asset, which is measured as the difference between the net carrying amount of the asset and the net proceeds received.

The estimated original useful life of each of our drilling units is 35 years. We reevaluate the remaining useful lives and salvage values of our rigs when certain events occur that directly impact the useful lives and salvage values of the rigs, including changes in operating condition, functional capability and market and economic factors. When evaluating the remaining useful lives of rigs, we also consider major capital upgrades required to perform certain contracts and the long-term impact of those upgrades on future marketability.

Long-lived asset impairment—We review the aggregate carrying amount of our long-lived assets, principally property and equipment, for potential impairment when events occur or circumstances change that indicate that the aggregate carrying amount of the drilling units and related equipment in our asset group may not be recoverable. We determine recoverability by evaluating the aggregate estimated undiscounted future net cash flows based on projected dayrates and utilization of our drilling units. When an impairment of our assets is indicated, we measure the impairment as the amount by which the aggregate carrying amount of the drilling units and related equipment in our asset group exceeds the aggregate estimated fair value. We measure the fair value of our drilling units and related equipment by applying a variety of valuation methods, incorporating a combination of income and market approaches, using projected discounted cash flows and estimates of the exchange price that would be received for the assets in the principal or most advantageous market for the assets in an orderly transaction between market participants as of the measurement date.

Goodwill impairment—We conduct impairment testing for our goodwill annually as of October 1 and more frequently, on an interim basis, when an event occurs or circumstances change that indicate that the fair value of a reporting unit may have declined below its carrying value. We test goodwill at the reporting unit level, which is defined as an operating segment or one level below an operating segment that constitutes a business for which financial information is available and is regularly reviewed by management. We have determined that we have a single reporting unit for this purpose. Before testing goodwill, we consider whether or not to first assess qualitative factors to determine whether the existence of events or circumstances lead to a determination that it is more likely than not that the fair value of a reporting unit is less than its carrying amount and whether the two-step impairment test is required. If, as the result of our qualitative assessment, we determine that the two-step impairment test is required, or, alternatively, if we elect to forgo the qualitative assessment, we test goodwill for impairment by comparing the carrying amount of the reporting unit, including goodwill, to the fair value of the reporting unit.

We estimate the fair value of our reporting unit using projected discounted cash flows, publicly traded company multiples and acquisition multiples. To develop the projected cash flows associated with our reporting unit, which are based on estimated future dayrates and rig utilization, we consider key factors that include assumptions regarding future commodity prices, credit market conditions and the effect these factors may have on our contract drilling operations and the capital expenditure budgets of our customers. We discount the projected cash flows using a long-term, risk-adjusted weighted-average cost of capital, which is based on our estimate of the investment returns that market participants would require for each of our reporting units. We derive publicly traded company multiples for companies with operations similar to our reporting units using observable information related to shares traded on stock exchanges and, when available, observable information related to recent acquisitions. If the reporting unit's carrying amount exceeds its fair value, we consider goodwill impaired and perform a second step to measure the amount of the impairment loss, if any. In the years ended December 31, 2014 and 2013, as a result of our annual impairment testing, we concluded that our goodwill was not impaired.

Contingencies—We perform assessments of our contingencies on an ongoing basis to evaluate the appropriateness of our liabilities and disclosures for such contingencies. We establish liabilities for estimated loss contingencies when we believe a loss is probable and the amount of the probable loss can be reasonably estimated. We recognize corresponding assets for those loss contingencies that we believe are probable of being recovered through insurance. Once established, we adjust the carrying amount of a contingent liability upon the occurrence of a recognizable event when facts and circumstances change, altering our previous assumptions with respect to the likelihood or amount of loss. We recognize expense for legal costs as they are incurred, and we recognize a corresponding asset for such legal costs only if we expect such legal costs to be recovered through insurance.

Net investment—Net investment on our consolidated balance sheets represents Transocean's historical investment in the Predecessor, the Predecessor's accumulated earnings and the net effect of cash transactions and allocations between Transocean and the Predecessor.

Reclassifications—We have made certain reclassifications, which did not have an effect on net income, to prior period amounts to conform with the current year's presentation. These reclassifications did not have a material effect on our consolidated statement of financial position, results of operations or cash flows.

Subsequent events—We evaluate subsequent events through the time of our filing on the date we issue our financial statements. See Note 17—Subsequent Events.

Note 3—New Accounting Pronouncements

Recently adopted accounting standards

Income taxes—Effective January 1, 2014, we adopted the accounting standards update that requires an unrecognized tax benefit to be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss or a tax credit carryforward if net settlement is required or expected. The update is effective for interim and annual periods beginning on or after December 15, 2013. Our adoption did not have an effect on our consolidated balance sheets or the disclosures contained in our notes to consolidated financial statements.

Recently issued accounting standards

Presentation of financial statements—Effective with our annual report for the period ending December 31, 2016, we will adopt the accounting standards update that requires us to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about our ability to continue as a going concern within one year after the date that the financial statements are issued. The update is effective for the annual period ending after December 15, 2016 and for annual periods and interim periods thereafter. We do not expect that our adoption will have a material effect on the disclosures contained in our notes to consolidated financial statements.

Revenue from contracts with customers—Effective January 1, 2017, we will adopt the accounting standards update that 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 update is effective for interim and annual periods beginning on or after December 15, 2016. We are evaluating the requirements to determine the effect such requirements may have on our revenue recognition policies.

Note 4—Income Taxes

Tax rate—We are organized as a limited liability company under the laws of The Republic of the Marshall Islands and are a resident in the United Kingdom ("U.K.") for taxation purposes. We are treated as a corporation for U.S. federal income tax purposes. Certain of our controlled affiliates, including the RigCos, are subject to taxation in the jurisdictions in which they are organized, conduct business or own assets.

The Republic of the Marshall Islands—Because we and our controlled affiliates do not conduct business or operations in The Republic of the Marshall Islands, neither we nor our controlled affiliates will be subject to income, capital gains, profits or other taxation under current Marshall Islands law. As a result, any distributions from our controlled affiliates are not subject to Marshall Islands taxation.

United Kingdom—We are a resident of the U.K. for taxation purposes. We expect that any distributions from our controlled affiliates generally will be exempt from taxation in the U.K. under the applicable exemption for distributions from subsidiaries.

United States—We have elected to be treated as a corporation for U.S. federal income tax purposes. As a result, we are subject to U.S. federal income tax to the extent we earn income from U.S. sources or income that is treated as effectively connected with the conduct of a trade or business in the U.S. We have controlled affiliates that conduct drilling operations in the U.S. Gulf of Mexico that are subject to taxation by the U.S. on their net income.

Cayman Islands—The Cayman Islands will not impose any income, capital gains, profits, withholding or other taxation on us, our controlled affiliates or on any distributions we or they may make.

Effective upon completion of the formation transactions, our provision for income taxes are computed based on the laws and rates applicable in the jurisdictions in which we operate and earn income. The Predecessor's provision for income taxes was prepared on a separate return basis with consideration to the laws and rates applicable in the jurisdictions in which the Predecessor's Business operated and earned income.

The Predecessor's income tax provision was based on the tax structure of Transocean Ltd., a holding company and Swiss resident, which is exempt from cantonal and communal income tax in Switzerland, but is subject to Swiss federal income tax. At the federal level, qualifying net dividend income and net capital gains on the sale of qualifying investments in subsidiaries are exempt from Swiss federal income tax. Consequently, Transocean Ltd.'s dividends from its subsidiaries and capital gains from sales of investments in its subsidiaries are exempt from Swiss federal income tax.

Our provision for income taxes was prepared on a separate return basis with consideration to the tax laws and rates applicable in the jurisdictions in which we operated and earned income. The components of our provision for income taxes were as follows (in millions):

	Years ended December 31, 2014	2013	2012
Current tax expense	$ 2	$ 8	$ 3
Deferred tax expense	18	15	21
Income tax expense	$ 20	$ 23	$ 24

We considered the earnings of the Predecessor to be indefinitely reinvested. As such, we have not provided for taxes on these unremitted earnings. If there were to be a distribution of these unremitted earnings, such distribution would be subject to withholding taxes in the U.S.

The following is a reconciliation of the differences between the income tax expense computed at (a) the Marshall Islands holding company federal statutory rate of zero percent for us in the year ended December 31, 2014 or (b) the Swiss holding company federal statutory rate of 7.83 percent for the Predecessor in the years ended December 31, 2013 and 2012 and the reported provision for income taxes (in millions):

	Years ended December 31, 2014	2013	2012
Income tax expense at the respective federal statutory rate	$ —	$ 17	$ 22
Taxes on earnings subject to rates different than the Marshall Islands federal statutory rate	15	4	—
Changes in unrecognized tax benefits, net	3	2	2
Changes in valuation allowance	2	—	—
Income tax expense	$ 20	$ 23	$ 24

Deferred taxes—The significant components of our deferred tax assets were as follows (in millions):

	December 31, 2014	2013
Deferred tax assets		
Net operating loss carryforwards	$ 2	$ —
Deferred revenues and drilling contract intangible	12	39
Valuation allowance	(2)	—
Other	3	5
Total deferred tax assets	15	44
Deferred tax liabilities		
Total deferred tax liabilities	—	—
Net deferred tax assets	$ 15	$ 44

During the three months ended December 31, 2014, we adjusted the deferred tax asset related to our drilling contract intangible to correct an error related to the remeasurement and contribution of such deferred tax asset in connection with our formation transactions. As a result of the correction, we recorded a reduction of $11 million to the deferred tax asset with a corresponding entry to total equity.

The Predecessor's income tax provision is based on the applicable rates in the jurisdictions in which the Predecessor's business operated and earned income. We believe our consolidated statements of financial position, results of operation and cash flows are materially correct as presented.

At December 31, 2014, the tax effect of our U.K. net operating losses, which does not expire, was $2 million.

The valuation allowance for our non-current deferred tax assets was as follows (in millions):

	December 31, 2014	December 31, 2013
Valuation allowance for non-current deferred tax assets	$ 2	$ —

Unrecognized tax benefits—The changes to our liabilities related to unrecognized tax benefits, excluding interest and penalties that we recognize as a component of income tax expense, were as follows (in millions):

	Years ended December 31, 2014	2013	2012
Balance, beginning of period	$ 12	$ 11	$ 9
Additions for current year tax positions	1	1	4
Reductions for prior year tax positions	(12)	—	—
Settlements	—	—	(2)
Balance, end of period	$ 1	$ 12	$ 11

The Predecessor's unrecognized tax benefits balance at December 31, 2013, originated in legal entities that were not transferred to us in the formation transactions which is reported as part of the reduction for prior year tax positions.

The liabilities related to our unrecognized tax benefits, including related interest and penalties that we recognize as a component of income tax expense, were as follows (in millions):

	December 31, 2014	December 31, 2013
Unrecognized tax benefits, excluding interest and penalties	$ 1	$ 12
Interest and penalties	—	1
Unrecognized tax benefits, including interest and penalties	$ 1	$ 13

In the year ended December 31, 2013, we recognized interest and penalties of less than $1 million associated with the unrecognized tax benefits and recorded as a component of income tax expense. As of December 31, 2014, if recognized, $1 million of the unrecognized tax benefits would favorably impact the effective tax rate.

It is reasonably possible that the existing liabilities for unrecognized tax benefits could increase or decrease in the year ending December 31, 2015, primarily due to the progression of open audits. However, we cannot reasonably estimate a range of potential changes in our existing liabilities for unrecognized tax benefits due to various uncertainties, such as the unresolved nature of various audits.

Tax returns—The Predecessor's results were reported in federal and local tax returns filed in the U.S. and Switzerland. With few exceptions, the Predecessor's results were no longer subject to examinations of tax matters for years prior to 2010.

Note 5—Earnings per unit

Our basic and diluted earnings per unit were the same because we did not have any potentially dilutive units outstanding for the periods presented. The numerator and denominator used for the computation of basic and diluted per unit earnings, were as follows (in millions, except per share data):

	Years ended December 31,		
	2014	2013	2012
Numerator for earnings per unit			
Net income attributable to controlling interest	$ 36	$ —	$ —
Net income available to common unitholders	$ 22	$ —	$ —
Net income available to subordinated unitholders	$ 14	$ —	$ —
Denominator for earnings per unit			
Weighted-average common units outstanding	41	—	—
Weighted-average subordinated units outstanding	28	—	—
Earnings per unit			
Earnings per common unit	$ 0.52	$ —	$ —
Earnings per subordinated unit	$ 0.52	$ —	$ —
Cash distributions declared and paid per unit			
Common units	$ 0.2246	$ —	$ —
Subordinated units	$ 0.2246	$ —	$ —

We have not presented earnings per unit calculations for the Predecessor periods, since the Predecessor had no units outstanding (see Note 2 —Significant Accounting Policies—Presentation).

See Note 9—Cash Distributions and Note 17—Subsequent Events.

Note 6—Goodwill and Intangible Liability

Goodwill—As of the closing of the formation transactions on August 5, 2014, Transocean allocated to us $356 million of goodwill based on the estimated fair value of our reporting unit relative to the estimated fair value of Transocean's reporting unit immediately prior to the allocation. Transocean estimated the fair value of our reporting unit using a variety of valuation methods, including the income and market approaches, by applying significant unobservable inputs, representative of a Level 3 fair value measurement, including assumptions related to the future performance of our reporting unit, such as future commodity prices, projected demand for our services, rig availability and dayrates. At December 31, 2014, the carrying amount of our goodwill was $356 million.

During the three months ended December 31, 2014, we observed a rapid and significant decline in the market value of our stock, the market value of Transocean's stock, prices of oil and natural gas and the actual and projected declines in dayrates and utilization, and we considered these indicators that the fair value of our goodwill could have fallen below its carrying amount, and as a result, we performed an interim goodwill impairment test. Although we determined that our goodwill was not impaired as of December 31, 2014, we concluded that our reporting unit was at risk of failing the first step of our goodwill impairment test, as the reporting unit's estimated fair value exceeded its carrying amount by less than 5 percent. If the market value of our stock declines below its previous 52-week low or if we experience increasingly unfavorable changes to actual or anticipated market conditions, or to other impairment indicators, any of which may result in the fair value of our reporting unit falling below its carrying amount, we may be required to recognize losses on impairment of goodwill in the near future.

Prior to August 5, 2014, Transocean allocated to the Predecessor a portion of the carrying amount of its goodwill based on the estimated fair value of the Predecessor's net property and equipment relative to the estimated fair value of Transocean's reporting unit, including the Predecessor's net property and equipment. The goodwill allocated to the Predecessor as of January 1, 2012, the measurement date for this purpose, was $213 million. Transocean estimated the fair value of the Predecessor's net property and equipment using a variety of valuation methods, including the income and market approaches, by applying significant unobservable inputs, representative of Level 3 fair value measurement, including assumptions related to the future performance of our reporting unit, such as future commodity prices, projected demand for our services, rig availability and dayrates. At December 31, 2013, the Predecessor's goodwill was $213 million.

Intangible liability—In connection with Transocean's business combination with GlobalSantaFe Corporation in November 2007, Transocean acquired *Development Driller III,* which had a drilling contract that included fixed dayrates for future contract drilling services that were below the then-existing market dayrates available for similar contracts as of the date of the business combination. Accordingly, Transocean recognized a contract intangible liability, representing the estimated fair value of the *Development Driller III* drilling contract, which is expected to be completed in November 2016. The Predecessor transferred to us the historical carrying amount of the intangible liability.

The gross carrying amounts of our drilling contract intangible liability and accumulated amortization were as follows (in millions):

	Year ended December 31, 2014			Year ended December 31, 2013		
	Gross carrying amount	Accumulated amortization	Net carrying amount	Gross carrying amount	Accumulated amortization	Net carrying amount
Drilling contract intangible liabilities						
Balance, beginning of period	$ 126	$ (82)	$ 44	$ 126	$ (64)	$ 62
Amortization	—	(15)	(15)	—	(18)	(18)
Balance, end of period	$ 126	$ (97)	$ 29	$ 126	$ (82)	$ 44

At December 31, 2014, the estimated future amortization of our drilling contract intangible liabilities was as follows (in millions):

	Drilling contract intangible liabilities
Years ending December 31,	
2015	$ 15
2016	14
Total intangible liabilities	$ 29

Note 7—Credit Agreements

Five-Year Revolving Credit Facility—On August 5, 2014, we entered into a credit agreement, which is scheduled to expire on August 5, 2019, with a Transocean affiliate to establish a committed $300 million five-year revolving credit facility that allows for uncommitted increases in amounts agreed to by the Transocean affiliate and us (the "Five-Year Revolving Credit Facility"). We may borrow under the Five-Year Revolving Credit Facility at either (1) the adjusted London Interbank Offered Rate ("LIBOR") plus a margin (the "revolving credit facility margin"), which ranges from 1.625 percent to 2.250 percent based on our leverage ratio, as defined, or (2) the base rate specified in the credit agreement plus the revolving credit facility margin, less one percent per annum. Throughout the term of the Five-Year Revolving Credit Facility, we are required to pay a commitment fee on the daily unused amount of the underlying commitment, which ranges from 0.225 percent to 0.325 percent based on our leverage ratio, as defined. Among other things, the Five-Year Revolving Credit Facility includes limitations on creating liens, incurring subsidiary debt, transactions with affiliates, sale/leaseback transactions, mergers and the sale of substantially all assets. The Five-Year Revolving Credit Facility also includes a covenant imposing a maximum debt ratio, as defined in the credit agreement. Borrowings under the Five-Year Revolving Credit Facility are subject to acceleration upon the occurrence of an event of default. At December 31, 2014, based on our leverage ratio on that date, the revolving credit facility margin was 1.625 percent. At December 31, 2014, we had no borrowings outstanding and $300 million available borrowing capacity under the Five-Year Revolving Credit Facility.

Working capital note payable and customer receivables guaranty agreements—On July 29, 2014, we entered into agreements with a Transocean affiliate to establish a working capital note payable in the principal amount and for cash proceeds of $43 million that is due and payable at maturity on July 28, 2015. The working capital note payable bears interest at the adjusted one-month LIBOR plus a margin (the "working capital note margin"), which ranges from 1.625 percent to 2.250 percent based on our leverage ratio, as defined in the Five-Year Revolving Credit Facility. The principal amount may be repaid early without penalty, and amounts repaid cannot be reborrowed. At December 31, 2014, based on our leverage ratio on that date, the working capital note margin was 1.625 percent.

The proceeds from the 364-day working capital note were used as partial consideration for contributed working capital in connection with the acquisition of interests in the RigCos. In connection with the acquisition, Transocean agreed to guarantee the payment of any receivables held by the RigCos at the closing of the acquisition. In addition, the assignment and bill of sale agreements for the acquisition contains a true-up mechanism whereby we will pay Transocean for the amount by which our pro rata share of actual net working capital, as determined within 60 days after the acquisition, exceeds our pro rata share of estimated net working capital at the time of the acquisition, and Transocean will pay us if such actual net working capital is less than such estimated net working capital. At December 31, 2014, the outstanding principal amount under the working capital note payable was $43 million. Subsequent to our formation, we determined that the working capital exceeded the original estimate by $4 million, and in the three months ended December 31, 2014, we made a cash payment in satisfaction of our obligation.

Former credit agreements—In March 2014, we entered into credit agreements with a Transocean affiliate establishing three credit facilities with an aggregate borrowing capacity of $300 million that was scheduled to expire on March 31, 2017. On August 5, 2014, we terminated the credit agreements. No borrowings were outstanding under the credit facilities at the time of termination.

Note 8—Commitments and Contingencies

Purchase obligations—At December 31, 2014, the aggregate future payments required under our purchase obligations for equipment, which are due in the year ending December 31, 2015, were $23 million.

Retained risk—Our fleet is covered under Transocean's hull and machinery and excess liability insurance program, which is comprised of commercial market and captive insurance policies, and Transocean allocated to us the premium costs attributable to our fleet. Transocean renews the commercial and captive policies under its insurance program annually on May 1. At December 31, 2014, our drilling units had the insured value of approximately $2.0 billion under this program. We also have coverage for losses resulting from physical damage to our fleet caused by named windstorms in the U.S. Gulf of Mexico, including liability for wreck removal costs, through Transocean's captive insurance program. We do not maintain insurance coverage through Transocean or the commercial market for loss of revenues.

Hull and machinery coverage—Our fleet is covered under Transocean's hull and machinery insurance for physical damage, for which it allocated to us the respective premium costs. In connection with this physical damage insurance coverage, we retained the risk for our per occurrence deductible of $10 million to $11 million. Subject to the same deductible, we also had coverage for an amount equal to 50 percent of a rig's insured value for combined costs incurred to mitigate rig damage, wreck or debris removal and collision liability. For losses in excess to our per occurrence deductible of $10 million to $11 million, Transocean provides insurance coverage for physical damage to our fleet through its wholly owned captive insurance company up to its deductible amounts and through its commercial insurance program beyond such deductible amounts. In connection with losses for any excess wreck removal costs, we are generally covered to the extent of Transocean's remaining excess liability coverage.

Excess liability coverage—Our fleet is covered under Transocean's excess liability coverage insurance, for which it allocated to us the respective premium costs. In connection with this excess liability insurance coverage, we retained the risk for a separate $10 million per occurrence deductible on collision liability claims and a separate $5 million per occurrence deductible applicable to crew personal injury claims and other third-party non-crew claims. For losses in excess to our deductible amounts, Transocean provides the primary $50 million of excess liability coverage, through its wholly owned captive insurance company, and for the $700 million excess of the $50 million of coverage through its commercial market excess liability program, which generally covers offshore risks such as personal injury, third-party property claims, and third-party non-crew claims, including wreck removal and pollution. We share the $750 million of captive and commercial market excess liability coverage with Transocean's entire fleet. We and Transocean generally retained the risk for any liability losses in excess of $750 million.

Other insurance coverage—Our fleet is covered under Transocean's marine package insurance program, and Transocean allocated to us the respective premium costs. Under this insurance program, we have access to $100 million of additional insurance that generally covered expenses that would otherwise be assumed by the well owner, such as costs to control the well, redrill expenses and pollution from the well. This additional insurance provided coverage for such expenses under circumstances in which we would have had legal or contractual liability arising from its gross negligence or willful misconduct.

Guarantees, letters of credit and surety bonds—At December 31, 2014 and 2013, we had no guarantees, letters of credit or surety bonds issued or outstanding.

Encumbered assets—Transocean had a $900 million three-year secured revolving credit facility established under a bank credit agreement dated October 25, 2012, that was scheduled to expire on October 25, 2015 (the "Transocean Three-Year Secured Revolving Credit Facility"). Transocean's borrowings under the Transocean Three-Year Secured Revolving Credit Facility were secured by three of its ultra-deepwater floaters, including its interests in the ultra-deepwater drillship *Discoverer Inspiration*. At December 31, 2013, Transocean had no borrowings outstanding under the Transocean Three-Year Secured Revolving Credit Facility. At December 31, 2013, the aggregate carrying amount of the ultra-deepwater drillship *Discoverer Inspiration* was $706 million. On June 30, 2014, Transocean terminated the Transocean Three-Year Secured Revolving Credit Facility and the related security agreement with respect to the ultra-deepwater drillship *Discoverer Inspiration*. At December 31, 2014, we had no assets subject to liens or other encumbrances.

Note 9—Cash Distributions

Cash distribution policy—Under our cash distribution policy, we intend to make minimum quarterly distributions on our common and subordinated units of $0.3625 per unit, equivalent to $1.45 per unit on an annualized basis, to the extent we have sufficient available cash after the establishment of cash reserves and the payment of costs and expenses, including the payment of expenses to the Transocean Member and its affiliates. However, other than the requirement in our limited liability company agreement to distribute all of our available cash each quarter, we have no legal obligation to make quarterly cash distributions in this or any other amount, and our board of directors has considerable discretion to determine the amount of our available cash each quarter. Generally, our available cash is our (i) cash on hand at the end of a quarter after the payment of our expenses and the establishment of cash reserves, including estimated maintenance and replacement capital expenditures, (ii) cash on hand on the date of determination resulting from cash distributions received after the end of such quarter from equity interests in any person other than a subsidiary in respect of operations conducted by such person during the quarter and (iii) if our board of directors so determines, cash on hand on the date of determination resulting from working capital borrowings made after the end of the quarter. If we do not generate sufficient available cash from our operations, we may, but are under no obligation to, borrow funds to pay minimum quarterly distributions to our unitholders.

For any quarter during the subordination period, which extends through the first business day following the distribution of available cash in respect of any quarter beginning with the quarter ending June 30, 2019, we will make distributions of our available cash from operating surplus among the unitholders and the holders of the incentive distribution rights in the following manner:

- *first*, 100 percent to the common unitholders, pro rata, until we distribute for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter;
- *second*, 100 percent to the common unitholders, pro rata, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period;
- *third*, 100 percent to the subordinated unitholders, pro rata, until we distribute for each subordinated unit an amount equal to the minimum quarterly distribution for that quarter; and
- *thereafter*, in the manner further described below.

The percentage interests set forth below assume that there are no arrearages on common units.

		Marginal percentage interest in distributions (a)	
	Total quarterly distribution target amount (a)	Unitholders	Holders of incentive distribution rights
Minimum quarterly distribution	$0.3625	100%	—
First target distribution	Above $0.3625 up to $0.416875	100%	—
Second target distribution	Above $0.416875 up to $0.453125	85%	15%
Third target distribution	Above $0.453125 up to $0.543750	75%	25%
Thereafter	Above $0.543750	50%	50%

(a) The marginal percentage interest in distributions represents the percentage interests of the unitholders and holders of incentive distribution rights in any available cash from operations surplus that we distribute up to and including the corresponding total quarterly distribution amount, until the available cash from operating surplus reaches the next target distribution level, if any. The percentage interests shown for the unitholders and the holders of incentive distribution rights for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution.

The Transocean Member holds 21.3 million common units and 27.6 million subordinated units, which collectively represents a 70.8 percent limited liability company interest, and all of our incentive distribution rights.

Cash distribution to unitholders—On November 4, 2014, our board of directors approved a distribution of $0.2246 per unit to unitholders. On November 24, 2014, we made an aggregate cash payment of $15 million to our unitholders of record as of November 17, 2014. Of the $15 million distribution, we paid $5 million, $4 million and $6 million to our public common unitholders, our Transocean common unitholder and our Transocean subordinated unitholder, respectively. See Note 17—Subsequent Events.

Note 10—Equity-Based Compensation Plan

Effective August 5, 2014, we established a long-term incentive plan (the “Incentive Compensation Plan”) for executives, key employees and non-employee directors under which awards can be granted in the form of unit options, unit appreciation rights, restricted units, or deferred units. Awards that may be granted under the Incentive Compensation Plan include time-vesting awards (“time-based awards”) and awards that are earned based on the achievement of certain performance criteria (“performance-based awards”) or market factors (“market-based awards”). Our executive compensation committee of our board of directors determines the terms and conditions of the awards granted under the Incentive Compensation Plan. As of December 31, 2014, we had no unit-based awards granted, and we had 3.4 million units authorized and available to be granted under the Incentive Compensation Plan. See Note 17—Subsequent Events.

Note 11—Related Party Transactions

Formation agreements

Contribution agreement—On July 29, 2014, we entered into a contribution agreement with Transocean that gave effect to certain of the formation transactions, including Transocean’s transfer to us of a 51 percent ownership interest in each of the RigCos. In connection with the formation transactions under the contribution agreement, Transocean retained the obligation for the payment of the quarterly royalty fees under the dual-activity license agreement through the patent expiration (see “—Other agreements—dual-activity license agreements”).

Transocean retains a significant interest in us through its ownership of common and subordinated units, representing an aggregate 70.8 percent limited liability company interest in us, and all of our incentive distribution rights. Transocean also holds the non-economic interest in us that includes the right to appoint three of the seven members of our board of directors. Under our limited liability company agreement, common unitholders that own 50 percent or more of our common units have the ability to request that cumulative voting be in effect for the election of elected directors. Cumulative voting is an irrevocable election that allows for the unitholder to allocate its votes cumulatively, rather than proportionally. Therefore, for so long as Transocean owns 50 percent or more of our common units, it will have the ability to request that cumulative voting be in effect for the election of elected directors, which would enable Transocean to elect one or more of the elected directors even after it owns less than 50 percent of our common units. As a result, if cumulative voting was in effect, Transocean would have the ability to appoint the majority of our board as long as it retains at least 20 percent of our common units. The directors appointed by Transocean may designate a member of the board of directors to be the chairman of the board of directors. Specific rights of the Transocean Member are designated in our limited liability company agreement.

Governing documents—Upon completion of the formation transactions, we own a 51 percent ownership interest in each of the RigCos and control their operations and activities. Transocean holds the remaining 49 percent noncontrolling interest in each of the RigCos. In connection with the formation transactions, we and certain Transocean affiliates entered into governing documents for each of the RigCos that govern the ownership and management of each of the RigCos. Each of the RigCos is managed by its board of directors. Pursuant to such governing documents, we are able to control the election of these boards of directors as the majority interest owner. Subject to certain prerequisites under applicable law and the approval of the board of directors of each of the RigCos, each RigCo intends to transfer its available cash to its equityholders each quarter. Approval of the conflicts committee of our board of directors is required to amend the RigCos' governing documents.

Master services and support agreements

Secondment agreements—On August 5, 2014, we entered into secondment agreements with certain Transocean affiliates to provide executives, including our chief executive officer, rig crews and other personnel. All persons provided to us pursuant to the secondment agreements will remain on the payroll and benefit plans of Transocean but will be under our day-to-day control and management. We will reimburse Transocean for the pro rata gross payroll costs of each seconded employee in proportion to the time allocated to us by the seconded employee, including base pay, any incentive compensation and any benefits costs. We will also reimburse Transocean for any applicable unemployment taxes, social security taxes, workers compensation coverage and severance costs, and any foreign equivalents of such taxes, in the amount allocable to the secondment. Transocean will invoice us quarterly for amounts payable under the secondment agreements. The secondment agreements may be terminated by Transocean or us upon 90 days written notice. In the year ended December 31, 2014, we recognized costs of $38 million, recorded in operating and maintenance costs and expenses, and $2 million, recorded in general and administrative costs and expenses, for personnel costs under the secondment agreements.

Support agreement—On August 5, 2014, we entered into a support agreement with certain Transocean affiliates to provide the services of certain administrative professionals, including our chief financial officer. The persons providing such services to us pursuant to the support agreement will remain on Transocean's payroll and will perform their services on or at Transocean's facilities. Transocean will be solely responsible for all matters pertaining to their employment, compensation and discharge. Such persons may spend only a portion of their time providing services to us and they may be engaged in other work separate from support services on our behalf. We will reimburse Transocean for the pro rata expenses associated with the compensation and benefits of all persons covered by the support agreement according to the time spent by each person in providing us support services as well as certain direct costs and expenses incurred in offering the services. The support agreement may be terminated by mutual agreement of Transocean and us. In the year ended December 31, 2014, we recognized costs of less than $1 million, recorded in operating and maintenance costs and expenses, and less than $1 million, recorded in general and administrative costs and expenses, for services under the support agreement.

Master services agreements—On August 5, 2014, we entered into master services agreements with certain Transocean affiliates, pursuant to which Transocean affiliates will provide certain administrative, technical and non-executive management services to us. Transocean affiliates will also provide insurance coverage to us commensurate with that provided to the Predecessor. The agreements have initial terms of five years. Each month, we will reimburse Transocean for the cost of all direct labor, materials and expenses incurred in connection with the provision of these services, plus an allocated portion of Transocean's shared and pooled direct costs, indirect costs and general and administrative costs as determined by Transocean's internal accounting procedures. In addition, we will pay Transocean a fee equal to the greater of (i) five percent of its costs and expenses incurred in connection with providing services to us for the month or, in the case of the provision of capital spares or inventory, a four percent markup on the capital spare or inventory plus a four percent markup on the allocable share of the costs of providing such services and, (ii) the markup required by applicable transfer pricing rules. If Transocean incurs costs and expenses from unaffiliated parties in the course of subcontracting the performance of services, we must reimburse Transocean at cost and is not required to pay a service fee, unless required by applicable transfer pricing rules. Amounts payable under the master services agreements must be paid within 30 days after Transocean submits to us invoices for such fees, costs and expenses. Each of the master services agreements may be terminated prior to the end of its term by either Transocean or us within 90 days written notice under certain circumstances. In the year ended December 31, 2014, we recognized costs of $46 million, recorded in operating and maintenance costs and expenses, and $11 million, recorded in general and administrative costs and expenses, for services under the master services agreement. In the year ended December 31, 2014, we acquired $13 million of materials and supplies purchased through the procurement services of Transocean Offshore Deepwater Drilling Inc. ("TODDI"). In the year ended December 31, 2014, we recognized insurance costs of $5 million, recorded in operating and maintenance costs and expenses.

Former master services agreement—Under the former master services agreement with TODDI, the Predecessor obtained services and assistance for certain activities, including accounting, legal, finance, marketing, tax, treasury, insurance, global procurement and technical services. In the years ended December 31, 2014, 2013 and 2012, the Predecessor recognized costs of $24 million, $35 million and $28 million, respectively, recorded in operating and maintenance costs and expenses, for such services and assistance.

Under the former master services agreement, TODDI purchased materials and supplies for the Predecessor's drilling operations through its procurement services. In the years ended December 31, 2014, 2013 and 2012, the Predecessor paid $27 million, $38 million and $29 million, respectively, settled through its net investment, for materials and supplies purchased through TODDI's procurement services.

Also under the former master services agreement, TODDI administered insurance coverage with and processed claims through Transocean's commercial market and captive insurance policies (see Note 8—Commitments and Contingencies). In the years ended December 31, 2014, 2013 and 2012, the Predecessor recognized allocated insurance costs of $8 million, $13 million and $14 million, respectively, recorded in operating and maintenance costs and expenses.

TODDI and its affiliates charged the Predecessor under the former master services agreement for crew personnel provided to the Predecessor to operate its drilling rigs. In the years ended December 31, 2014, 2013 and 2012, the Predecessor recognized costs of $57 million, $91 million and $81 million, respectively, recorded in operating and maintenance costs and expenses, for such personnel costs. In the years ended December 31, 2014, 2013 and 2012, the Predecessor recognized costs of $2 million, $9 million and $8 million, respectively, recorded in operating and maintenance costs and expenses, for the proportion of the benefit costs that covered the personnel supporting the Predecessor's operations.

Other agreements

Omnibus agreement—On August 5, 2014, we entered into an omnibus agreement with Transocean and certain of its affiliates (the "Omnibus Agreement"). Under the Omnibus Agreement, Transocean granted us a right of first offer for its remaining ownership interests in each of the RigCos should Transocean decide to sell such interests. Transocean also will be required to offer us within five years of the effective date of the Omnibus Agreement, the opportunity to purchase, subject to requisite government and other third-party consents, not less than a 51 percent interest in any four of the following six ultra-deepwater drillships: *Deepwater Invictus*, *Deepwater Thalassa*, *Deepwater Proteus*, *Deepwater Pontus*, *Deepwater Poseidon* and *Deepwater Conqueror*. The purchase price for each drillship will be equal to the greater of the fair market value, taking into account the anticipated cash flows under the associated drilling contracts, or the all-in construction cost, plus transaction costs. Transocean will select which of these drillships it will offer to us, the timing of the offers and whether it will offer us the opportunity to purchase a greater than 51 percent interest in any offered drillship. In addition, Transocean agreed not to acquire, own or operate any new drilling rig or contract for any drilling rig, in each case that was constructed in 2009 or later and is operating under a contract for five or more years ("Five-Year Drilling Rigs"), subject to certain exceptions, without offering us the opportunity to purchase such rig. We also agreed not to acquire, own, operate, or contract for any drilling rig that is not a Five-Year Drilling Rig, subject to certain exceptions, without first offering the contract to Transocean.

Transocean agreed to indemnify us for a period of five years through August 5, 2019 against certain environmental and human health and safety liabilities with respect to the assets contributed or sold to us to the extent arising prior to the time they were contributed or sold to us. Liabilities resulting from a change in law after the closing of the offering are excluded from the environmental indemnity. The indemnity coverage provided by Transocean for such environmental and human health and safety liabilities will not exceed the aggregate amount of $10 million. No claim for indemnification may be made unless the aggregate dollar amount of all claims exceeds $500,000, in which case Transocean is liable for claims only to the extent such aggregate amount exceeds $500,000.

In addition, Transocean agreed to indemnify us against any liabilities arising out of the Macondo well incident occurring prior to our initial public offering and any liabilities, other than taxes, arising from Transocean's or its subsidiaries' failure to comply with the Consent Decree or the EPA Agreement, each as it is defined in the Omnibus Agreement, or any similar decree or agreement. The indemnity coverage provided by Transocean related to the Macondo well incident, the Consent Decree, the EPA Agreement or any similar decree or agreement is unlimited. However, these indemnities do not cover or include any amount of consequential damages, including lost profits or revenues.

Transocean also agreed to indemnify us to the full extent of any liabilities related to:

- certain defects in title to Transocean's assets contributed or sold to the RigCos and any failure to obtain, prior to the time they were contributed, certain consents and permits necessary to conduct, own and operate such assets, which liabilities arise within three years after the closing of the offering;
- any judicial determination substantially to the effect that the Transocean affiliate that transferred any of our initial assets to us pursuant to the contribution agreement did not receive reasonably equivalent value in exchange therefor or was rendered insolvent by such transfer;
- tax liabilities attributable to the operation of the assets contributed or sold to the RigCos prior to the closing of the offering; and
- any lost revenue, up to $100 million, arising out of the failure to receive an operating dayrate from Chevron for *Discoverer Clear Leader*, for the period commencing on the closing date of the offering through the completion of the rig's 2014 special periodic survey, which is expected to occur during the three months ending December 31, 2014.

In the year ended December 31, 2014, we submitted indemnification claims for an aggregate amount of $19 million associated with lost revenues, and we recognized a receivable from affiliate with a corresponding entry to members' equity. In October 2014, we received from Transocean a cash payment of $9 million. At December 31, 2014, the outstanding indemnification claim receivable was $10 million, recorded in receivables from affiliates.

Dual-activity license agreements—All three of our drilling units are equipped with Transocean's patented dual-activity technology. Dual-activity technology employs structures, equipment and techniques using two drilling stations within a dual derrick to perform drilling tasks. Dual-activity technology allows our rigs to perform simultaneous drilling tasks in a parallel rather than sequential manner and reduces critical path activity, improving efficiency in both exploration and development drilling. The Predecessor entered into license agreements with TODDI for the use of the patented technology through the expiration of the patents in May 2016. Under the license agreements, the Predecessor paid to TODDI an aggregate original license cost of $20 million, recorded in other assets. In the years ended December 31, 2014, 2013 and 2012, we and the Predecessor recognized amortization of the license costs of $2 million, $3 million and $3 million, respectively, recorded in operating and maintenance costs and expenses. At December 31, 2014 and 2013, the carrying amount of the deferred license cost was $4 million and $7 million, respectively.

Also, under the license agreements, we are and the Predecessor was required to pay to TODDI quarterly patent royalty fees of between 3 percent and 5 percent of revenues. Under the contribution agreement, Transocean retained the obligation for the payment of the quarterly patent royalty fees (see "—Formation agreements—Contribution agreement"). In the years ended December 31, 2014, 2013 and 2012, we recognized patent royalty expense of $23 million, $19 million and $21 million, respectively, recorded in operating and maintenance costs and expenses. Of the $23 million patent royalty expense recognized in the year ended December 31, 2014, we recognized a non-cash expense of $7 million with a corresponding entry to members' equity, representing the fees paid by Transocean on our behalf with a corresponding entry to members' equity.

Credit agreements—In March 2014, we entered into credit agreements with TODDI, establishing three credit facilities with an aggregate borrowing capacity of $300 million, and effective as of August 5, 2014, we terminated these credit agreements. On July 29, 2014, we entered into agreements with a Transocean affiliate to establish a working capital note payable in the principal amount and for cash proceeds of $43 million. On August 5, 2014, we entered into the Five-Year Revolving Credit Facility with a Transocean affiliate. See Note 7—Credit Agreements.

Note 12—Supplemental Cash Flow Information

Additional cash flow information was as follows (in millions):

	Years ended December 31,		
	2014	2013	2012
Certain cash operating activities			
Cash payments for income taxes	$ —	$ 6	$ 1
Non-cash investing and financing activities			
Capital additions, accrued at end of period (a)	$ 6	$ 1	$ —
Property and equipment transferred to the Predecessor from affiliates (b)	10	1	21
Property and equipment transferred from the Predecessor to affiliates (c)	(23)	—	—
Contribution for parent payment of dual-activity patent royalties (d)	7	—	—
Contribution for parent indemnification of lost revenues (e)	10	—	—

(a) These amounts represent additions to property and equipment for which we had accrued a corresponding liability at the end of the period.

(b) In the years ended December 31, 2014, 2013 and 2012, Transocean transferred to the Predecessor certain equipment, primarily all of which was to *Development Driller III*, and the Predecessor recorded the non-cash investing activity with a corresponding entry to its net investment.

(c) In the year ended December 31, 2014, the Predecessor transferred to Transocean's other drilling units certain equipment with an aggregate net carrying amount of $23 million, primarily all of which was from *Development Driller III*, and the Predecessor recorded the non-cash investing activity with a corresponding entry to its net investment.

(d) In the year ended December 31, 2014, in connection with Transocean's payment of $7 million of royalty fees under our dual-activity license agreements with a Transocean affiliate, we recognized non-cash operating expense with a corresponding increase to members' equity.

(e) In the year ended December 31, 2014, we submitted indemnification claims associated with lost revenues for an aggregate amount of $19 million, representing a capital contribution recognized in members' equity. At December 31, 2014, the unpaid balance was $10 million, recorded in accounts receivable from affiliates.

Note 13—Financial Instruments

The carrying amounts and fair values of our financial instruments were as follows:

	December 31, 2014		December 31, 2013	
	Carrying amount	Fair value	Carrying amount	Fair value
Cash and cash equivalents	$ 86	$ 86	$ —	$ —
Working capital note payable to affiliate	43	43	—	—

We estimated the fair value of each class of financial instruments, for which estimating fair value is practicable, by applying the following methods and assumptions:

Cash and cash equivalents—The carrying amount of cash and cash equivalents represents the historical cost, plus accrued interest, which approximates fair value because of the short maturities of those investments. We measured the estimated fair value of our cash equivalents using significant other observable inputs, representative of a Level 2, fair value measurement, including the net asset values of the investments. At December 31, 2014, the aggregate carrying amount of our cash equivalents was $40 million.

Working capital note payable to affiliate—The carrying amount of the working capital note payable approximates fair value due to the short term nature of the instrument. We measured the estimated fair value of our working capital note payable using significant unobservable inputs, representative of a Level 3, fair value measurement, including the credit spreads that would be considered at market for a borrower with our credit ratings.

Note 14—Risk Concentration

Credit risk—Financial instruments that potentially subject us to concentrations of credit risk are primarily trade receivables. We derive all of our revenues from services to two international oil companies and conduct all of our operations in the U.S. Gulf of Mexico. We are not aware of any significant credit risks related to our customer base and do not generally require collateral or other security to support customer receivables.

Note 15—Operating Segments, Geographic Analysis and Major Customers

Operating segments—We operate in a single market for the provision of contract drilling services to our customers. The location of our rigs and the allocation of our resources to build or upgrade rigs are determined by the activities and needs of our customers.

Geographic analysis—For the years ended December 31, 2014, 2013 and 2012, we earned 100 percent of our consolidated operating revenues in the U.S. Gulf of Mexico. At December 31, 2014 and 2013, 100 percent of our assets were in the U.S. Gulf of Mexico.

Major customers—For the year ended December 31, 2014, Chevron Corporation and BP plc accounted for approximately 67 percent and 33 percent, respectively, of our consolidated operating revenues. For the year ended December 31, 2013, Chevron Corporation and BP plc accounted for approximately 67 percent and 33 percent, respectively, of our combined operating revenues. For the year ended December 31, 2012, Chevron Corporation and BP plc accounted for approximately 68 percent and 32 percent, respectively, of our combined operating revenues.

Note 16—Quarterly Results (unaudited)

Our consolidated statement of operations for the year ended December 31, 2014 consists of the consolidated results of operations of Transocean Partners for the period from August 5, 2014 through December 31, 2014 and the combined results of operations of the Predecessor for the beginning of the respective period through August 4, 2014. Our consolidated statements of operations for the year ended December 31, 2013 consist entirely of the combined results of operations of the Predecessor. See Note 2—Significant Accounting Policies-Presentation.

	Three months ended			
	March 31,	June 30,	September 30,	December 31,
	(In millions, except per share data)			
2014				
Operating revenues	$ 148	$ 145	$ 136	$ 138
Operating income	69	55	60	49
Net income	63	50	57	45
Net income attributable to controlling interest	(a)	(a)	17	19
Per unit earnings - basic and diluted				
Common units	$ (a)	$ (a)	$ 0.24	$ 0.28
Subordinated units	$ (a)	$ (a)	$ 0.24	$ 0.28
Weighted-average units outstanding				
Common units	(a)	(a)	41	41
Subordinated units	(a)	(a)	28	28
2013				
Operating revenues	$ 116	$ 133	$ 147	$ 130
Operating income	40	52	67	49
Net income	36	47	60	46

(a) Amounts associated with the Predecessor period, and, therefore, not applicable. See Note 2—Significant Accounting Policies.

Note 17—Subsequent Events

Distribution to unitholders—On February 9, 2015, our board of directors approved a distribution of $0.3625 per unit to our unitholders. We expect to pay the aggregate cash distribution of $25 million on February 26, 2015 to unitholders of record as of February 20, 2015, including an aggregate cash payment of $18 million to the Transocean unitholder.

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

We have not had a change in or disagreement with our accountants within 24 months prior to the date of our most recent financial statements or in any period subsequent to such date.

Item 9A. Controls and Procedures

Disclosure controls and procedures—We carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures, as defined in the Exchange Act, Rules 13a-15 and 15d-15, were effective as of December 31, 2014 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is (1) accumulated and communicated to our management, including our Chief Executive Officer and our Chief Financial Officer, to allow timely decisions regarding required disclosure and (2) recorded, processed, summarized and reported within the time periods specified in the U.S. Securities and Exchange Commission's rules and forms.

Internal control over financial reporting—There were no changes to our internal control over financial reporting during the quarter ended December 31, 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

This annual report does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of our registered public accounting firm due to a transition period established by rules of the U.S. Securities and Exchange Commission for newly public companies.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Item 11. Executive Compensation

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters

Item 13. Certain Relationships, Related Transactions, and Director Independence

Item 14. Principal Accounting Fees and Services

The information required by Items 10, 11, 12, 13 and 14 is incorporated herein by reference to our definitive proxy statement for our 2015 annual general meeting of unitholders, which will be filed with the U.S. Securities and Exchange Commission pursuant to Regulation 14A under the Securities Exchange Act of 1934 within 120 days of December 31, 2014. Certain information with respect to our executive officers is set forth in Item 4 of this annual report under the caption “Executive Officers of the Registrant.”

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Index to Financial Statements, Financial Statement Schedules and Exhibits

(1) Index to Financial Statements

Financial statements of unconsolidated subsidiaries are not presented herein because such subsidiaries do not meet the significance test.

(2) Financial Statement Schedules

Financial statement schedules have been omitted because they are either not required, not applicable or because the required information is included in the financial statements or notes thereto.

(3) Exhibits

The following exhibits are filed in connection with this Report:

Number	Description
3.1	Second Amended and Restated Limited Liability Company Agreement of Transocean Partners LLC, dated as of July 29, 2014 (incorporated by reference to Exhibit 3.1 to Transocean Partners LLC's Current Report on Form 8-K (Commission File No. 001-36584) filed on August 5, 2014)
3.2	Certificate of Formation of Transocean Partners LLC, dated February 6, 2014 (incorporated by reference to Exhibit 3.1 to Transocean Partners LLC's registration statement on Form S-1 as amended (Commission File No. 333-196958))
10.1	Omnibus Agreement dated as of August 5, 2014 (incorporated by reference to Exhibit 10.1 to Transocean Partners LLC's Current Report on Form 8-K (Commission File No. 001-36584) filed on August 5, 2014)
10.2	Master Services Agreement dated as of August 5, 2014 (Transocean Offshore Deepwater Drilling Inc.) (incorporated by reference to Exhibit 10.2 to Transocean Partners LLC's Current Report on Form 8-K (Commission File No. 001-36584) filed on August 5, 2014)
10.3	Master Services Agreement dated as of August 5, 2014 (Transocean Partners Holdings Limited) (incorporated by reference to Exhibit 10.3 to Transocean Partners LLC's Current Report on Form 8-K (Commission File No. 001-36584) filed on August 5, 2014)
10.4	Secondment Agreement dated as of August 5, 2014 (incorporated by reference to Exhibit 10.4 to Transocean Partners LLC's Current Report on Form 8-K (Commission File No. 001-36584) filed on August 5, 2014)
10.5	Support Agreement dated as of August 5, 2014 (incorporated by reference to Exhibit 10.5 to Transocean Partners LLC's Current Report on Form 8-K (Commission File No. 001-36584) filed on August 5, 2014)
10.6	Contribution, Conveyance and Assumption Agreement dated as of July 29, 2014 (incorporated by reference to Exhibit 10.6 to Transocean Partners LLC's Current Report on Form 8-K (Commission File No. 001-36584) filed on August 5, 2014)
10.7	Credit Agreement dated as of August 5, 2014, between Transocean Partners LLC, as borrower, and Transocean Financing GmbH, as lender (incorporated by reference to Exhibit 10.7 to Transocean Partners LLC's Current Report on Form 8-K (Commission File No. 001-36584) filed on August 5, 2014)
10.8	Working Capital Promissory Note dated as of July 29, 2014 (incorporated by reference to Exhibit 10.8 to Transocean Partners LLC's Current Report on Form 8-K (Commission File No. 001-36584) filed on August 5, 2014)
10.9	Assignment and Bill of Sale regarding Transocean RIGP DIN LLC dated as of August 1, 2014 (incorporated by reference to Exhibit 10.9 to Transocean Partners LLC's Current Report on Form 8-K (Commission File No. 001-36584) filed on August 5, 2014)
10.10	Assignment and Bill of Sale regarding Transocean RIGP DCL LLC dated as of August 1, 2014 (incorporated by reference to Exhibit 10.10 to Transocean Partners LLC's Current Report on Form 8-K (Commission File No. 001-36584) filed on August 5, 2014)

	10.11	Assignment and Bill of Sale regarding Transocean RIGP DD3 LLC dated as of August 1, 2014 (incorporated by reference to Exhibit 10.11 to Transocean Partners LLC's Current Report on Form 8-K (Commission File No. 001-36584) filed on August 5, 2014)
*	10.12	Transocean Partners LLC 2014 Incentive Compensation Plan (incorporated by reference to Exhibit 10.12 to Transocean Partners LLC's Current Report on Form 8-K (Commission File No. 001-36584) filed on August 5, 2014)
*	10.13	Form of Indemnity Agreement (incorporated by reference to Exhibit 10.13 to Transocean Partners LLC's Current Report on Form 8-K (Commission File No. 001-36584) filed on August 5, 2014)
*	10.14	Transocean Partners LLC Executive Severance Policy (incorporated by reference to Exhibit 10.4 to Transocean Partners LLC's Current Report on Form 8-K (Commission File No. 001-36584) filed on August 5, 2014)
†	21	Subsidiaries of Transocean Partners LLC
†	24	Powers of Attorney
†	31.1	CEO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
†	31.2	CFO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
†	32.1	CEO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
†	32.2	CFO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
†	101.INS	XBRL Instance Document
†	101.SCH	XBRL Taxonomy Extension Schema
†	101.CAL	XBRL Taxonomy Extension Calculation Linkbase
†	101.DEF	XBRL Taxonomy Extension Definition Linkbase
†	101.LAB	XBRL Taxonomy Extension Label Linkbase
†	101.PRE	XBRL Taxonomy Extension Presentation Linkbase

† Filed herewith.
* Compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

TRANSOCEAN PARTNERS LLC
By: /s/ Garry Taylor
Garry Taylor
Chief Financial Officer
(Principal Financial Officer)
Date: February 26, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
* Esa Ikäheimonen	Chairman of the Board of Directors	February 26, 2015
/s/ Kathleen S. McAllister Kathleen S. McAllister	President, Chief Executive Officer (Principal Executive Officer)	February 26, 2015
/s/ Garry Taylor Garry Taylor	Chief Financial Officer (Principal Financial Officer)	February 26, 2015
* Glyn Barker	Director	February 26, 2015
* Michael Lynch-Bell	Director	February 26, 2015
* Samuel Merksamer	Director	February 26, 2015
* John Plaxton	Director	February 26, 2015
* Norman J. Szydlowski	Director	February 26, 2015
/s/ Garry Taylor (Attorney-in-Fact)		

Exhibit 31.1

CEO CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Kathleen S. McAllister, certify that:

1. I have reviewed this report on Form 10-K of Transocean Partners LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and we have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: February 26, 2015

/s/ Kathleen S. McAllister
Kathleen S. McAllister
President and Chief Executive Officer

Exhibit 31.2

CFO CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Garry Taylor, certify that:

1. I have reviewed this report on Form 10-K of Transocean Partners LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and we have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: February 26, 2015

/s/ Garry Taylor
Garry Taylor
Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO SECTION 906 OF
THE SARBANES-OXLEY ACT OF 2002 (SUBSECTIONS (a) AND (b)
OF SECTION 1350, CHAPTER 63 OF TITLE 18, UNITED STATES CODE)

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code), I, Kathleen S. McAllister, President and Chief Executive Officer of Transocean Partners LLC, a Marshall Islands limited liability company (the "Company"), hereby certify, to my knowledge, that:

(1) the Company's Annual Report on Form 10-K for the year ended December 31, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 26, 2015

/s/ Kathleen S. McAllister
Kathleen S. McAllister
President and Chief Executive Officer

The foregoing certification is being furnished solely pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the U.S. Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

CERTIFICATION PURSUANT TO SECTION 906 OF
THE SARBANES-OXLEY ACT OF 2002 (SUBSECTIONS (a) AND (b)
OF SECTION 1350, CHAPTER 63 OF TITLE 18, UNITED STATES CODE)

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code), I, Garry Taylor, Chief Financial Officer of Transocean Partners LLC, a Marshall Islands limited liability company (the "Company"), hereby certify, to my knowledge, that:

(1) the Company's Annual Report on Form 10-K for the year ended December 31, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 26, 2015

/s/ Garry Taylor
Garry Taylor
Chief Financial Officer

The foregoing certification is being furnished solely pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the U.S. Securities and Exchange Commission or its staff upon request.